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A SOLUTION IN SEARCH OF A PROBLEM: EPA'S METHANE REGULATIONS

HEARING

BEFORE THE

SUBCOMMITTEE ON ENVIRONMENT

COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY

HOUSE OF REPRESENTATIVES

ONE HUNDRED FOURTEENTH CONGRESS

SECOND SESSION

September 15, 2016

Serial No. 114–93

Printed for the use of the Committee on Science, Space, and Technology

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A SOLUTION IN SEARCH OF A PROBLEM: EPA'S METHANE REGULATIONS

THURSDAY, SEPTEMBER 15, 2016

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENVIRONMENT,
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY,
Washington, D.C.

The Subcommittee met, pursuant to call, at 10:03 a.m., in Room 2318, Rayburn House Office Building, Hon. Jim Bridenstine [Chairman of the Subcommittee] presiding.

LAMAR S. SMITH, Texas
CHAIRMAN

EDDIE BERNICE JOHNSON, Texas
RANKING MEMBER

Congress of the United States
House of Representatives
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
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Subcommittee on Environment

A Solution In Search of a Problem: EPA's Methane Regulations

Thursday, September 15, 2016
10:00 a.m. – 12:00 p.m.
2318 Rayburn House Office Building

Witnesses

Mr. Erik Milito, Director, Upstream and Industry Operations, American Petroleum Institute

Dr. Bernard Weinstein, Professor and Associate Director, Maguire Energy Institute, Cox School of Business, Southern Methodist University

Mr. Elgie Holstein, Senior Director for Strategic Planning, Environmental Defense Fund

Mr. Anthony J. Ventello, Executive Director, Progress Authority

U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY

HEARING CHARTER

Thursday, September 15, 2016

TO: Members, Subcommittee on Environment

FROM: Majority Staff, Committee on Science, Space, and Technology

SUBJECT: Subcommittee hearing: "A Solution In Search of a Problem: EPA's Methane Regulations"

The Subcommittee on Environment will hold a hearing titled *A Solution In Search of a Problem: EPA's Methane Regulations* on Thursday, September 15, 2016, at 9:30 a.m. in Room 2318 of the Rayburn House Office Building.

Hearing Purpose:

The purpose of this hearing is to examine the impact of EPA's recent regulatory activity on methane gas. Witnesses will also discuss implementation, economic and other associated issues of the methane rules at the national and state level.

Witness List

- **Mr. Erik Milito**, *Director, Upstream and Industry Operations, American Petroleum Institute*
- **Dr. Bernard Weinstein**, *Professor, Associate Director, Maguire Energy Institute, Cox School of Business, Southern Methodist University*
- **Mr. Elgie Holstein**, *Senior Director for Strategic Planning, Environmental Defense Fund*
- **Mr. Anthony J. Ventello**, *Executive Director, Progress Authority*

Staff Contact

For questions related to the hearing, please contact Majority Staff at 202-225-6371.

Chairman BRIDENSTINE. All right. We're going to go ahead and get started. We have votes happening between 10:00 and 10:30, so we're going to start just as soon as we can here if our witnesses can take their positions.

When we break for votes, we'll come back here and continue the hearing immediately following votes. I think we'll only have one vote, so it shouldn't take too long and get as much information as we can before we all fly home for the weekend.

The Subcommittee on the Environment will come to order. Without objection, the Chair is authorized to declare recesses of the subcommittee at any time.

Welcome to today's hearing entitled "A Solution in Search of a Problem: EPA's Methane Regulations." I recognize myself for five minutes for an opening statement.

Today's hearing will examine the impact of the Environmental Protection Agency's recent regulatory activity on methane gas. We will also discuss implementation, economic impacts, and other associated issues regarding the methane rules at the national and the state level.

I am concerned about the EPA's expansive interpretation of its regulatory scope and its continued use of questionable scientific bases for rulemaking. My concern extends to the EPA's methane rule.

This past May, EPA Administrator McCarthy stated that she will expedite issuing regulations for reducing methane emissions from existing sources. Rather than expedite methane regulation, EPA should take a breath and realize that the best available science does not support new rulemaking. But once again, EPA is back at it with cherry-picking and fudging data to fit a politically driven agenda aided by a cabal of establishment environmentalists.

A study published earlier this year by National Oceanic and Atmospheric Administration scientists found that the expansion of oil and gas production is not to blame for a global increase in methane emissions. That was NOAA. That was their study. And according to the study's author, "The U.S. energy industry contributes little to the overall burden of global fossil fuel emissions." According to this NOAA study, wetlands, which naturally generate methane, and agriculture from sources outside the United States are the main contributors to emissions.

Here at home, the oil and gas industry has drastically cut methane emissions through responsible voluntary efforts. Technological advances under development and implemented by industry will only lead to further reductions, without the need for costly and burdensome EPA regulations.

Leading energy researchers, including the National Economic Research Associates, dispute and challenge EPA's claims that reducing methane leaks by 45 percent by 2025 will be equivalent to shutting down one third of the world's coal-fired power plants. EPA is simply exaggerating their claims. A study by NERA concludes that the supposed benefits from EPA's methane rules are highly uncertain and very likely overstated.

The actual reduction in global temperatures is also minimal. Energy In Depth found that the rules would reduce global temperatures by a mere 4/1000 of a degree Celsius over the next 84 years,

4/1000 of a degree Celsius. We can't even measure that. Even if we shut down and stopped all American oil and gas production, it will have no impact on global temperatures.

And the cherry-picking of the science does not stop there. Issues of data integrity have continually dogged EPA during and after the regulatory process behind the methane rules. Before the final methane rule for new sources was released, the EPA conveniently increased its estimates of methane emissions from petroleum and natural gas systems without specifically identifying these emissions. It conveniently revised the greenhouse gas inventory for methane, adding 85 million metric tons to the U.S. methane emissions. Of course, EPA released this report ahead of their final rule.

And it gets worse. In order for EPA to justify their new-found activism, EPA assumed that the emissions from marginal wellheads, their profiles were similar to those of higher-producing wells and claimed the use of "new methodology." However, EPA had previously admitted that marginal wells have "inherently low" emissions.

What is clear and supported by the facts is that the recent economic boom is real. Communities have benefited tremendously from the resurgence of natural gas extraction when extracted safely and efficiently and responsibly. While states like New York have seen good-paying jobs and the associated economic benefits go to the wayside because of their moratorium on hydraulic fracturing for natural gas extraction, States like my State of Oklahoma have experienced the opposite.

Ranking fifth in energy production, Oklahoma practices an all-of-the-above strategy when it comes to energy. Last year, Oklahoma produced an all-time high, 2.5 trillion cubic feet of natural gas. That number indicates a 50 percent increase in production over ten years. The increased production of natural gas has coincided with a decrease in methane emissions. In the last ten years, the state of Oklahoma has increased its production of natural gas by 50 percent, and it has coincided with a decrease in methane emissions.

Oklahoma is leading the way in demonstrating that responsible exploration and production with industry-led voluntary emission reduction practices realizes decreased emissions without burdensome mandates from the EPA. I would also like to applaud my Attorney General, Scott Pruitt, for joining the lawsuit challenging the methane emissions regulations.

As we will hear today, the shale revolution has changed the U.S. economy and has been responsible for creating good-paying jobs. Instead of focusing on environmental protection, however, the EPA is now pursuing a war on natural gas.

I want to thank each of our witnesses for coming. I look forward to hearing your testimonies. And I will yield back the balance of my time, of which there is none remaining.

[The prepared statement of Chairman Bridenstine follows:]

COMMITTEE ON
SCIENCE, SPACE, & TECHNOLOGY
Lamar Smith, Chairman

For Immediate Release
September 15, 2016

Media Contact: Kristina Baum
(202) 225-6371

Statement of Environment Subcommittee Chairman Jim Bridenstine (R-Okla.)
A Solution in Search of a Problem: EPA's Methane Regulation

Chairman Bridenstine: Good morning and welcome to this morning's hearing entitled: "A Solution In Search of a Problem: EPA's Methane Regulations".

Today's hearing will examine the impact of the Environmental Protection Agency's (EPA) recent regulatory activity on methane gas. We will also discuss implementation, economic impacts, and other associated issues regarding the methane rules at the national and state level.

I am concerned about the EPA's expansive interpretation of its regulatory scope and its continued use of questionable scientific basis for rulemaking. My concern extends to EPA's methane rule.

This past May, EPA Administrator McCarthy stated that she will expedite issuing regulations for reducing methane emissions from existing sources. Rather than expedite methane regulation, EPA should take a breath and realize that the best available science does not support new rulemaking. But once again, EPA is back at it with cherry-picking and fudging data to fit a politically-driven agenda aided by a cabal of establishment environmentalists.

A study published earlier this year by National Oceanic and Atmospheric Administration (NOAA) scientists found that the expansion in oil and gas production is not to blame for a global increase in methane emissions, and according to the study's author, "the U.S. energy industry contributes little to the overall burden of global fossil fuel emissions." According to this NOAA study, wetlands, which naturally generate methane, and agriculture, from sources outside the United States, are the main contributors to emissions.

Here at home, the oil and gas industry has drastically cut methane emissions through responsible voluntary efforts. Technological advances under development and implemented by industry will only lead to further reductions, without the need for costly and burdensome EPA regulations.

Leading energy researchers, including the National Economic Research Associates, dispute and challenge EPA's claims that reducing methane leaks by 45% by 2025 will be equivalent to shutting down one-third of the world's coal-fired power plants. EPA is simply exaggerating their claims. A study by NERA concludes that the supposed benefits from EPA's methane rules are highly uncertain and very likely overstated.

The actual reduction in global temperatures is also minimal – Energy in Depth found that the rules would reduce global temperatures by a mere 0.004 degrees Celsius over the next 84 years. Even if we shut down and stopped all American oil and gas production, it will have no impact on global temperatures.

And the cherry-picking of science does not stop there. Issues of data-integrity have continually dogged EPA during and after the regulatory process behind the methane rules. Before the final methane rule for new sources was released, the EPA also conveniently increased its estimates of methane emissions from petroleum and natural gas systems, without specifically identifying these emissions. It conveniently revised the greenhouse gas inventory for methane, adding 85 million metric tons to the US methane emissions.

Of course, EPA released this report ahead of their final rule. And it gets worse – in order for EPA to justify their new-found activism, EPA assumed that marginal wells had emissions profiles similar to those of higher producing wells and claimed the use of "new methodology." However, EPA had previously admitted that marginal wells have "inherently low" emissions.

What is clear and supported by the facts is that the recent economic boom experience is real. Communities have benefited tremendously from the resurgence of natural gas extraction when extracted safely and responsibly. While states like New York have seen good paying jobs and the associated economic benefits go to the wayside because of their moratorium on hydraulic fracturing for natural gas extraction, states like my home state of Oklahoma have experienced the opposite.

Ranking fifth in energy production, Oklahoma practices an "all of the above" strategy when it comes to energy. Last year, Oklahoma produced, an all-time high, 2.5 trillion cubic feet of natural gas. That number indicates a 50% increase in production over 10 years. The increased production of natural gas has coincided with a decrease in methane emissions. Oklahoma is leading the way in demonstrating that responsible exploration and production with industry-led voluntary emission reduction practices realizes decreased emissions without burdensome mandates from the EPA. I would also like to applaud my Attorney General, Scott Pruitt, for joining the lawsuit challenging the methane emissions regulations.

As we will hear today, the shale revolution has not only revolutionized the US economy and has been responsible for creating good-paying jobs. Instead of focusing on environmental protection, the EPA is now pursuing a war on natural gas.
I want to thank each of the witnesses for coming this afternoon and I look forward to hearing from our witnesses today and yield back the balance of my time.

###

Chairman BRIDENSTINE. I will now recognize the Ranking Member from Oregon, Ms. Bonamici, for five minutes.

Ms. BONAMICI. Thank you, Mr. Chairman, and thank you to the witnesses for being here today.

Methane leaks and releases are a real problem for the health and safety of Americans across the country. Unlike the billowing smoke that rises from some coal-fired power plants, methane releases and leaks are nearly indistinguishable to a passerby. Oftentimes, environmental repercussions stemming from atmospheric pollution are easy to recognize. Higher ozone levels reduce visibility in the form of smog, which is easy to see. Higher concentrations of carbon dioxide in the atmosphere are ultimately absorbed by the ocean, resulting in a more acidic ocean that has a visible impact on shellfish in coastal economies.

Methane emissions have similar environmental repercussions, but because methane is colorless and odorless, it is easy to forget that it is a highly potent greenhouse gas. Once methane is released into the atmosphere, it is 80 percent more potent than carbon dioxide for the following 20 years in terms of its effect on the climate.

I'd like to put up a slide that will better provide an understanding of what a methane leak looks like.

[Slide.]

Ms. BONAMICI. Last fall, a natural gas storage tank at Aliso Canyon outside of Los Angeles began leaking methane at an alarming rate. The leak was discovered by the gas company on October 23, and it took 4 months for that leak to be completely fixed. In that time, those plumes continued to rise and thousands of gallons of methane poured into the atmosphere; 8,000 residents were displaced from their homes for months; residents suffered headaches, nosebleeds, and nausea.

And just to clarify, here on the right there is infrared camera revealing the wafting cloud of methane over the Aliso Canyon.

Incidents like this highlight the importance of EPA's methane regulations, specifically the leak detection component. Although the new rule only addresses methane emissions at new, reconstructed, and modified oil and gas sources, it represents an important first step, a step that needs to be made so that the problems of today are not the problems of tomorrow.

We don't want another Aliso Canyon. We need to work together so that we do not have methane emissions in our country. I look forward to discussing this important issue today. I want to allow plenty of time for the witnesses, so I yield back the balance of my time, Mr. Chairman.

[The prepared statement of Ms. Bonamici follows:]

OPENING STATEMENT
Ranking Member Suzanne Bonamici (D-OR)
of the Subcommittee on Environment

House Committee on Science, Space, and Technology
Subcommittee on Environment
"A Solution in Search of a Problem: EPA's Methane Regulations"
September 15, 2016

Thank you Mr. Chairman, and thank you to the witnesses for being here today. I would particularly like to thank Mr. Elgie Holstein of the Environmental Defense Fund, who has done a considerable amount of work on methane releases, and the environmental impacts of methane.

Despite the title for this hearing, methane leaks and releases are a real problem for many Americans all over this country on a daily basis. Unlike the billowing smoke that rises from some coal fired power plants, methane releases and leaks are nearly imperceptible to a passerby. It is therefore easy to forget how potent a greenhouse gas methane actually is. Once methane is released into the atmosphere it is 80 percent more potent than carbon dioxide over the next 20 years in terms of its impact on the climate.

Oftentimes environmental impacts stemming from atmospheric pollution are easy to see. Higher ozone levels reduce visibility in the form of smog, in addition to creating greater health risks. Higher concentrations of carbon dioxide in the atmosphere are ultimately absorbed by the ocean, resulting in a more acidic ocean that has a visible impact on shellfish, and other economic problems. Methane emissions have similar environmental impacts but due to its chemistry it is often difficult to visualize.

I'd like to put up a slide that will give some of you a better understanding of what a methane leak looks like <call for slide>. Last fall, a natural gas storage tank at Aliso Canyon outside of Los Angeles began leaking methane at an alarming rate. The leak was discovered by the gas company on October 23rd and it took four months for that leak to be completely fixed. In that time, those plumes continued to rise, and thousands of gallons of methane poured into the atmosphere.

Incidents like this highlight the importance of EPA's methane regulations. While the new rule only addresses methane emissions at new, reconstructed, and modified oil and gas sources, it is an important first step to ensure that the problems of today are not the problems of tomorrow. I look forward to discussing this important issue today, and I yield back.

Chairman BRIDENSTINE. The gentlelady yields back the balance of her time. I now recognize the Chairman of the full committee, Mr. Smith, for five minutes.

Chairman SMITH. Thank you, Mr. Chairman.

I just want to say to our panelists here today, a vote has been called and so we'll be interrupted, regrettably. And furthermore, it's oftentimes difficult to get members to come back after the last vote of the day. They're running to the airport and so forth. So if our attendance is not as great as we would like, that doesn't diminish the value of your testimony today.

Mr. Chairman, the Environmental Protection Agency has become an agency that promotes an extreme political agenda rather than reasonable policies based on sound science. The EPA knows its regulatory agenda would have little to no significant impact on the environment. But that hasn't stopped the EPA from imposing some of the most expensive and expansive regulations in its history.

These rules will cost billions of dollars, place a heavy burden on American families, and diminish the ability of American businesses to compete around the world. EPA's political agenda is to rearrange the American economy and institute "command and control" by the Obama Administration.

This committee's investigations have revealed that the EPA intentionally chooses to ignore good science. EPA cherry-picks the science that fits its agenda and ignores the science that does not support its position. When the science falls short, EPA resorts to propaganda campaign techniques designed to mislead the public.

Today's hearing will examine yet another EPA regulation that has relied on suspect science, questionable legal interpretations, and flawed analysis to justify its existence.

Like all regulations promulgated by the EPA, the methane regulation is no different. It stifles economic growth, destroys American jobs, and increases energy prices. That means costs will rise, from electricity to gasoline to food, disproportionately hurting low-income Americans.

According to Energy In Depth, by the end of this century the EPA's supposed benefits from the final methane rule for new sources will only result in a reduction—now, the Chairman just mentioned this a moment ago—reduction of 4/1000 of one degree Celsius in temperature rise. That is incredible.

Recent studies involving National Oceanographic and Atmospheric Administration scientists conclude that the rise in methane emissions are not due to the oil and gas sector, which are the target of the EPA's regulations. These scientists conclude that the likely rise in methane emissions are from natural sources like tropical wetlands.

Emissions from the oil and gas sector continue to decrease in large part because of the voluntary emissions reductions programs and advances in technologies. This indicates the futility of new and burdensome EPA regulations. During the last year, federal courts have halted several of EPA's major regulations. Many of these regulations trample on the constitutional rights of individuals and rely on suspect legal interpretations of the law.

EPA's methane rule relies on faulty scientific evidence and data, and the final rule constitutes an abuse of authority. For this rea-

son, my home state of Texas, along with North Dakota, are planning to pursue legal action. Instead of wasting taxpayers' money on frivolous rules that do little to protect the environment, the EPA should spend its resources on developing sound science that will lead to technological breakthrough.

The methane rule is more of the same from the EPA: a costly and burdensome regulation that is all pain and no gain.

Thank you, Mr. Chairman. I yield back.

[The prepared statement of Chairman Smith follows:]

COMMITTEE ON
SCIENCE, SPACE, & TECHNOLOGY
Lamar Smith, Chairman

For Immediate Release
September 15, 2016

Media Contact: Kristina Baum
(202) 225-6371

Statement of Chairman Lamar Smith (R-Texas)
A Solution in Search of a Problem: EPA's Methane Regulation

Chairman Smith: Thank you Mr. Chairman. The Environmental Protection Agency (EPA) has become an agency that promotes an extreme political agenda rather than reasonable policies based on sound science.

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According to Energy in Depth, by the end of this century the EPA's supposed benefits from the final methane rule for new sources will only result in a reduction of four-thousandths of one degree Celsius in temperature rise. Absolutely incredible!

Recent studies involving National Oceanographic and Atmospheric Administration scientists conclude that the rise in methane emissions are not due to the oil and gas sector, which are the target of the EPA regulations. These scientists conclude that the likely rise in methane emissions are from natural sources, like tropical wetlands.

Emissions from the oil and gas sector continue to decrease in large part because of voluntary emissions reductions programs and advances in technologies. This indicates the futility of new and burdensome EPA regulations. During the last year, Federal Courts have halted several of EPA's major regulations. Many of these regulations trample on the constitutional rights of individuals and rely on suspect legal interpretations of the law.

EPA's methane rule relies on faulty scientific evidence and data and the final rule constitutes an abuse of authority. For this reason, my home state of Texas along with North Dakota are planning to pursue legal action. Instead of wasting taxpayers' money on frivolous rules that do little to protect the environment, the EPA should spend its resources on developing sound science that will lead to technological breakthrough.

The methane rule is more of the same from the EPA: a costly and burdensome regulation that is all pain and no gain.

###

Chairman BRIDENSTINE. Thank you, Mr. Chairman.

What we're going to do now is recess. We have one vote. I'll be right back to introduce the witnesses and hear your testimony. So until we get back from voting, we'll be in recess. Thank you.

[Recess.]

Chairman BRIDENSTINE. The Subcommittee on Environment will come back to order.

Let me introduce our witnesses. Our first witness today is Mr. Erik Milito, Director of Upstream and Industry Operations at the American Petroleum Institute. Mr. Milito received his bachelor's degree in business administration from Notre Dame and his law degree from Marquette University.

Our next witness today is Dr. Bernard Weinstein—Weinstein—Weinstein?

Dr. WEINSTEIN. Weinstein.

Chairman BRIDENSTINE. Stein, got it. I'm Bridenstine so everybody calls me Bridenstine so—Professor and Associate Director at the Maguire Energy Institute at Southern Methodist University's Cox School of Business. Dr. Weinstein received his bachelor's degree in public administration from Dartmouth University and his master's degree and Ph.D. in economics from Columbia.

Our third witness today is Mr. Elgie Holstein——

Mr. HOLSTEIN. Holstein.

Chairman BRIDENSTINE. Holstein, got it—Senior Director for Strategic Planning at the Environmental Defense Fund. Mr. Holstein received his bachelor's degree from Syracuse University.

Our final witness today is Mr. Anthony Ventello, Executive Director of Progress Authority. Mr. Ventello received his bachelor's degree in geographic and regional planning from Mansfield University, his master's degree in public administration from Marywood University, and his American Economic Development Council certification from Penn State.

I now recognize Mr. Milito for five minutes for your opening testimony.

TESTIMONY OF MR. ERIK MILITO, DIRECTOR, UPSTREAM AND INDUSTRY OPERATIONS, AMERICAN PETROLEUM INSTITUTE

Mr. MILITO. Thank you, Chairman Bridenstine, Ranking Member Bonamici, and Members of the Subcommittee.

My name is Erik Milito, and I'm the Director of Upstream and Industry Operations for the American Petroleum Institute. We have witnessed a dramatic transformation of the energy landscape over the past ten years both here in the United States and globally. Looking back ten years ago, we spoke in terms of energy scarcity, and the expectation was that we as a country would be importing billions of dollars of natural gas from places like the Middle East, Russia, and West Africa. The outlook was the same on the petroleum side. We were expecting U.S. oil production to flatten or decline to about 5 million barrels per day.

Fortunately, we have experienced an energy resurgence that has brought with it tremendous benefits for everyday Americans. We as a nation rely on oil and natural gas in everything that we do from

getting to work, getting our kids to school, to heating and cooling our homes, and to using the stovetop to put dinner on the table.

Because of innovation and the advancement of engineering technologies such as hydraulic fracturing and horizontal drilling, the United States is now the world's largest natural gas producer. And on the petroleum side, we've increased our production from 5 million barrels per day in 2009 to a peak of 9.4 million barrels a day, and this is all because of advanced technology, hydraulic fracturing, horizontal drilling, and being able to tap into those resources in our shale formations.

Clearly, we now speak in terms of energy abundance. Consumers are the first ones to benefit from our energy resurgence. A recent study by IHS concludes that the average household had an additional $1,300 in 2015 because of U.S. shale gas production. AAA estimates that the average American saved $550 at the pump in 2015, and this also relates to U.S. crude oil production.

We have also seen major benefits from a global geopolitical and energy security standpoint. The United States now plays a major role in global energy markets, and this has helped our allies tremendously because there are now greater, more diverse energy supplies on the global market.

We have proven as a nation and as an industry that we are able to achieve these economic and national security benefits while not only protecting the environment but by providing tangible environmental benefits. From a climate standpoint, the United States has seen its greenhouse gas emissions dropped to 20-year lows. This is directly attributable to the increased use of clean-burning, abundant, affordable natural gas in the power generation sector. Not only has natural gas helped us achieve important reductions in greenhouse gas emissions, but it also produces little to no particulate matter, nitrogen dioxide, and sulfur dioxide, contributing to cleaner air for all Americans.

Interestingly enough, in spite of this dramatic increase in U.S. production of natural gas, emissions of methane from our industry have decreased over the past 20 years. Now, the story here is the same. We've accomplish this by advancing the technologies to ensure that we are capturing methane, which is the primary component of natural gas. We have shown that the solution to addressing methane emissions is through the development and application of technologies through innovation, not through a command-and-control regulatory approach that can effectively stifle innovation and add unnecessary costs.

I'd like to point out that methane emissions were declining before EPA promulgated any regulations, demonstrating that these regulations are simply not necessary. Our policies should effectively promote U.S. energy production and the benefits for everyday Americans, not jeopardize the success that we have achieved and that we should continue to achieve with smart policy choices.

Thank you. I look forward to your questions.

[The prepared statement of Mr. Milito follows:]

Testimony of Erik Milito, Upstream Director
American Petroleum Institute
Before the Subcommittee on Environment
House Committee on Science, Space and Technology
Hearing on EPA's Methane Regulations
September 15, 2016

The dramatic resurgence of the United States as an energy superpower over the past decade has provided tremendous benefits for the country, with significant savings in energy costs for everyday Americans, critical national security improvement, and environmental benefits from the application of advanced technologies and the increased use of clean-burning, abundant natural gas. The U.S. oil and natural gas industry has proven that we can develop the energy that our economy relies upon here at home, while ensuring that those resources are developed safely and responsibly. This includes developing and applying technologies and best practices that effectively reduce emissions of methane, which is the key component of natural gas and thus a vital product for our industry to bring to the U.S. market.

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested more than $3 trillion in U.S. capital projects to advance all forms of energy, including alternatives. API's members are at the forefront of technology advancement and innovation and include many of the nation's largest producers of oil and natural gas.

Nationwide, as well as globally, there is an increasing reliance on the usage of natural gas. This has been made possible in the United States as a result of the application of the advanced engineering technologies of hydraulic fracturing and horizontal drilling. These technologies have unlocked significant quantities of natural gas once thought inaccessible, and have elevated the U.S. to the world's largest producer of natural gas. Furthermore, due to industry's leadership in the deployment of mitigation measures and investment in new technologies, petroleum and natural gas companies are reducing their releases of all greenhouse gases (GHGs), and in particular methane. North

American investments in GHG mitigating technologies are estimated to have totaled $431.6 billion (2010 dollars) between 2000 and 2014. U.S. based petroleum and natural gas companies invested an estimated $217.5 billion in GHG mitigating technologies, significantly more than other U.S. based private industries, which invested an estimated $102.8 billion, and the Federal Government, which invested an estimated $111.3 billion.[i] The industry clearly is a leader in reducing emissions, without the imposition of additional regulations.

Natural gas is an extremely clean burning fuel. According to the Energy Information Administration, use of natural gas has surpassed coal in generating electricity, and carbon dioxide (CO2) emissions from the power sector are at 20 year lows, primarily due to the increased use of natural gas for electricity generation.[ii] Increased use of natural gas has also led to lower emissions of criteria pollutants such as sulfur dioxide (SO2), nitrogen dioxide (NO2) and fine particulate matter (PM).

Additionally, it is expected that natural gas will remain important to many sectors of the U.S. economy, including electricity generation, industrial heating, chemical feedstocks, and residential and commercial water and space heating.[iii] In its 2016 Annual Energy Outlook (AEO), the EIA projects that U.S. natural gas consumption will rise, an average of about 1% annually to 2040.[iv] The industrial and electric power sectors make up 49% and 34% of this expected growth, respectively, while consumption growth in the residential, commercial, and transportation sectors is projected to be much lower.

The EPA's U.S. greenhouse gas inventory (GHGI) is comprised of emission estimates for seven GHG compounds or groups of compounds. When examining emissions from 1990-2014, methane emissions from natural gas systems - associated with the operation of natural gas systems for exploration, production, processing, transmission and distribution – declined from a high of 206.6 million metric tons of carbon dioxide equivalent (MMT CO2e) in 1990 to the current estimate of 176.1 MMT CO2e for 2014, a decline of 14.8 percent.[v] Over the same period of time, U.S. natural gas production increased by 47%. In other words, U.S emissions of methane from the natural gas

sector decreased noticeably during one of the largest increases in natural gas production in the nation's history.

As an aside, EPA's latest GHGI, which provides the data referenced above, also includes retrospective revisions to the annual methane emissions from the natural gas sector. These revisions retrospectively change the methane emissions of natural gas sector in a manner that shows a smaller decrease in methane emission from previous iterations of the GHGI. EPA's retrospective revisions are seriously flawed in the manner in which they extrapolated the data to non-reporting sources and API encourages EPA to correct the inventory.

Industry innovation and a continuous commitment to emission reductions have contributed to methane emission reductions from oil and natural gas sources. Some of the emission reduction technologies implemented by industry include installation of vapor recovery units, development of techniques for reduced emissions during well completions, increased use of lower-emitting pneumatic controllers and pumps, among other things.

Despite the success of the industry in reducing methane emissions, the industry is under threat of various regulations that will impose significant costs without commensurate benefits. The Environmental Protection Agency recently finalized a suite of new regulations targeting our industry. Each of the EPA rules -- Control Techniques Guidelines, Source Determination, Minor Source Tribal New Source Review, and the New Source Performance Standard for the Oil and Natural Gas Sector -- will likely significantly impact on our industry's operations and, collectively, they have the potential to hinder our ability to continue providing the energy our nation demands. These cumulative impacts must be considered in conjunction with the impacts of the lowered ozone standards and the pending Bureau of Land Management (BLM) methane rule, which will likely require costly methane controls for some of the very same emission sources being regulated by EPA. All of this comes on top of State regulation of our industry as well.

More specifically, API has raised numerous concerns with EPA's New Source Performance Standards (NSPS) for the oil and natural gas sector (40 CFR Part 60, Subpart OOOOa). API's comments on the rule are provided for the record. Many of API's concerns stem from the broad applicability of the final rule and the one-size-fits-all approach to regulating an industry that varies greatly in the type, size and complexity of operations. EPA has justified the regulation using economic studies on "average model facilities" without determining whether the resulting control requirements are appropriate for the entire range of sources included in the source category. The rule applies NSPS in unique and unprecedented ways to categories and equipment not previously listed, while relying on unsound legal justification. The notification, monitoring, recordkeeping, performance testing and reporting requirements are significantly more burdensome than justified for the small and/or temporarily affected facilities.

EPA's cost benefit analysis for the rule is unsound. EPA estimates a net $150 million annual benefit from the rule. In order to achieve this net benefit , EPA applied a social cost of methane (SC-CH_4) estimate on the benefit side that is highly speculative, not sufficiently peer-reviewed, and ultimately not suitable for policy applications. Independent review by NERA found that the benefits provided by the rule, after compensating for flaws in EPA's calculation, could be as much as 94% lower. When combined with the revised cost estimates and reduced emission benefits found in API's analysis, the rule could result in net costs of more than $1 billion in 2025. (See attached API RIA comments and NERA report.)

The OOOOa rule discussed above applies to new and modified sources in the oil and natural gas sector. EPA is also now collecting data through an Information Collection Request (ICR) to determine whether or how to regulate existing sources in the oil and natural gas sector. Rather than directly moving to the regulation of existing sources, API supports the ICR as an appropriate step to better understand existing sources. However, EPA's ICR as proposed would be overly expansive and unclear, and, if it

remains unchanged, will not provide relevant, useful data. API's comments on EPA's proposed ICR are provided for the record.

API urges EPA to simplify and streamline the information gathering in the ICR, so that the effort reduces the burden to industry while adequately identifying the appropriate data required for understanding existing sources of methane emissions in our industry.

Specifically, the ICR should:

- Provide operators (the industry) a voluntary process to identify proper contact information prior to mailing either Part of the ICR.
- Reduce the scope and burden of the Part 1 ICR by simplifying the data parameters requested for every well facility.
- Modify the sampling approach proposed in Part 2 for onshore production facilities in a way that will reduce the overall sample size and still meet accuracy goals of the Agency.
- Concentrate the Part 2 information request on options that identify useful life of existing equipment and equipment turnover; engineering limitations for controlling existing equipment; and improving EPA's understanding of production decline and associated impacts on emissions.
- Allow Industry the opportunity to review and comment on future emission estimation methodologies to be used by EPA in developing representative model plants.

In addition, the proposed scope and timelines of the draft ICR are aggressive and unrealistic for the amount of information the EPA is seeking. As drafted, EPA has significantly underestimated the burden associated with responding to the ICR and has not provided realistic response deadlines for operators. API suggests a streamlined scope that provides EPA with relevant data and provides realistic reporting timeframes.

In conclusion, methane emission reduction trends by the industry are now observable despite major increases in the production and use of natural gas. Improved policy measures, removal of bureaucratic barriers, and regulatory certainty are imperative to allow these trends to accelerate and lead to even greater GHG emission reductions, as well as the benefits of reduced air pollutants such as SO2, NO2 and PM. Innovation and technological advancement through the free-market, rather than command and control regulations, have proven to be the solution to environmental questions and should be embraced by regulators and policy makers moving forward.

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[i] T2 and Associates, "Key Investments in Greenhouse Gas Mitigation Technologies from 2000 Through 2014 by Energy Firms, Other Industry and the Federal Government", September 2015; http://www.api.org/~/media/files/ehs/climate-change/2015-t2-key-investments-in-ghg-mitigation.pdf

[ii] EIA, Today in Energy, U.S. energy-related carbon dioxide emissions in 2015 are 12% below their 2005 levels, May 9, 2016; http://www.eia.gov/todayinenergy/detail.cfm?id=26152

[iii] EIA, Today in Energy, Industrial and electric power sectors drive projected growth in U.S. natural gas use, May 26, 2016; http://www.eia.gov/todayinenergy/detail.cfm?id=26412

[iv] EIA, Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases, May 17, 2016; http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2016).pdf, U. S. EPA, Greenhouse Gas Inventory Report 1990-2014, April 2016

[v] U. S. EPA, Greenhouse Gas Inventory Report 1990-2014,, April 2016; https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2016-Main-Text.pdf

Erik Milito, American Petroleum Institute

Erik Milito is the Director of Upstream and Industry Operations for the American Petroleum Institute (API), which is the national trade association representing more than 600 companies involved in all aspects of the oil and gas industry, including exploration production, refining and transportation. Mr. Milito's work covers regulatory and legislative matters related to domestic exploration and production, including access to domestic oil and natural gas resources both onshore and offshore. Prior to his current position, Mr. Milito served as managing counsel covering a host of legal issues, including oil and gas leasing, royalty, environmental, fuels, transportation, safety, and civil justice reform.

Prior to joining API, Mr. Milito served for over four years on active duty in the U.S. Army as a judge advocate, and an additional four years in the U.S. Army Reserve, resigning at the rank of Major. Mr. Milito was assigned to active duty tours in Hawaii, Korea and Aberdeen Proving Ground, Maryland, and he served as a prosecutor, defense attorney and command advisor. Mr. Milito was awarded the Meritorious Service Medal and Army Commendation Medals during his military tenure. After leaving the Army, Mr. Milito worked as a career attorney with the Solicitor's Office of the U.S. Department of the Interior. While at Interior, Mr. Milito worked on oil and natural gas law, employment law, and disability access issues.

Mr. Milito attended the University of Notre Dame on an R.O.T.C. scholarship, and received a bachelor's degree in business administration. Mr. Milito then received his juris doctor from Marquette University Law School, where he was a member of the law review.

Mr. Milito has testified about industry efforts related to offshore drilling safety before the Senate Energy and Natural Resources Committee, the House Natural Resources Committee, the House Committee on Science and Technology, the Senate Subcommittee on Oceans, Atmosphere, Fisheries and Coast Guard, the National Commission on the Deepwater Horizon Oil Spill, and the National Academy of Engineering Investigation of the Spill. Mr. Milito testified before the Senate Energy and Natural Resources Committee and the House Natural Resources Committee on offshore oil and gas issues, and the House Subcommittee on Energy and Mineral Resources in hearings related to development of unconventional oil and gas resources. Mr. Milito testified before the Senate Energy and Natural Resources Committee and the House Natural Resources Committee on the agreement between the United States and Mexico to allow development of oil and natural gas resources along the countries maritime border in the Gulf of Mexico that has since been approved by Congress and the President. Mr. Milito also testified before the House Subcommittee on Nonproliferation, Trade and Terrorism about the importance of crude oil exports to the economy and national security. Mr. Milito has authored and co-authored several journal articles related to natural resources issues, including a chapter in the recently published *Hydraulic Fracturing: Environmental Issues, ACS Symposium Series 1216*. He routinely serves as a keynote and guest speaker on U.S. energy topics, and has appeared on CNN, C-SPAN, FoxNews and various other news outlets.

Mr. Milito formerly served on the Board of Trustees of the Rocky Mountain Mineral Law Foundation, and on the Board of Directors of the Alexandria, Virginia Boys and Girls Club. Erik and his wife Beth have four children, Will, Helen, Evie, and Jake and live in Alexandria, VA.

Chairman BRIDENSTINE. Thank you for your testimony.
Dr. Weinstein, you're recognized for five minutes.

TESTIMONY OF DR. BERNARD WEINSTEIN,
PROFESSOR, ASSOCIATE DIRECTOR,
MAGUIRE ENERGY INSTITUTE,
COX SCHOOL OF BUSINESS,
SOUTHERN METHODIST UNIVERSITY

Dr. WEINSTEIN. Thank you, Mr. Chairman, Members of the Committee, for the opportunity to speak today. I'm Bernard Weinstein. I'm Associate Director of the Maguire Energy Institute, as the Chairman mentioned, and we do a bunch of things at the Institute. We do student education, professional development, and we also do research on energy issues and policies. And we've worked for a number of organizations, done studies for—most recently for the Small Gasoline Retailers Coalition, we've worked with the Nuclear Energy Institute, Consumer Energy Alliance. We've done some work for the American Wind Energy Association, so we're across the board when it comes to energy.

But we're here to talk about methane, especially errant methane, and we all know this is a potent greenhouse gas and we don't want a lot of it going into the air. Recently, as you know, EPA did finalize a rule requiring drilling companies to install new monitoring equipment on production and transmission of oil and natural gas. EPA itself estimates the compliance costs will reach about $530 million annually by 2025. And they're also developing new regs for existing wells and processing equipment.

And the question is, and I guess the question of this hearing is do we really need more federal intervention, more regulatory oversight? How big a problem are we dealing with? And if you could put up the first slide.

[Slide.]

Dr. WEINSTEIN. Mr. Milito mentioned this, but you can see that U.S. methane emissions today are lower than they were in 1990. And when you consider that the economy is 75 percent larger and that oil and gas production has nearly doubled, that is a pretty amazing accomplishment.

And what's more, again, as Mr. Milito mentioned, only about 23 percent of errant methane is attributable to the oil and gas industry, and that's been declining. Emissions from fracked wells are down 79 percent, down 94 percent from pipelines. There are other sources of methane, as we all know, that probably contribute a lot more: wetlands, agriculture, landfills, et cetera.

We heard the Chairman talking about different studies. I refer to those studies in my final testimony so I won't repeat the findings. But even if we did shut in all of our oil and gas wells, that would have little or no impact on the environment as long as other countries continue doing what they're doing. I mean, you know, China builds a new coal plant every week. Turkey just announced they're building 30 new coal plants. They are 50 or 60 on the drawing board in India.

And so I think we need a dose of realism when we talk about, you know, what we can do in the United States. And I would argue that we've done a lot. If you put the next slide up——

[Slide.]

Dr. WEINSTEIN. —carbon emissions—again, we've already heard this—have dropped dramatically over the past decade. You can see that on the right. They dropped by about, you know, 1 trillion tons per year, which again is pretty incredible.

And why has this happened? It's because we're using more natural gas and because we're substituting natural gas in power generation for coal, we're using more natural gas in transportation, we're using more natural gas in industrial boilers, and that is helping to clean up the environment. Now, I would argue that greater use of natural gas, not EPA regulations, deserves most of the credit for our reductions in greenhouse gases, and to some degree methane.

So I'm an economist. Economists, I think, would all agree that regulation is not cost-free. And if you're going to impose new regulations, there are going to be economic consequences. As you know, the oil and gas industry has been under some stress of late. I'm not sure it would make a lot of political sense to apply new regulations, new costs on the industry today, especially because the industry on its own has taken steps to capture errant methane.

I would argue that voluntary and market-based solutions to reducing methane make a lot more sense and can probably achieve the Administration's goals better than new EPA regulations. If we monitor everything, we're simply wasting resources.

In my prepared testimony, I discuss a voluntary program called ONE Future in which a number of gas producers are working with EDF to reduce methane leaks to less than one percent of production. Maybe Mr. Holstein is going to talk about that program. I don't believe they're doing that out of environmental altruism. I think they're doing it because it makes economic sense because methane has value, so why wouldn't you want to capture it? It's used for power, it's used for heating, it's used for transportation, it's used for petrochemicals. If there are market-based or voluntary solutions that can achieve the goals of regulation at lower cost, those are the ones that should be pursued first.

So thanks for your attention. I'm happy to answer any questions at the appropriate time.

[The prepared statement of Dr. Weinstein follows:]

Testimony of Bernard L. Weinstein, Ph.D.

Associate Director, Maguire Energy Institute

Cox School of Business

Southern Methodist University, Dallas, Texas

Before the House Committee on Science, Space, and Technology

Subcommittee on Environment

Hearing on EPA Methane Regulations on Oil and Gas Production

September 15, 2016

Mr. Chairman and Members of the Committee, my name is Bernard Weinstein and I am the Associate Director of the Maguire Energy Institute at Southern Methodist University (SMU) and an adjunct professor of business economics at SMU's Cox School of Business. Thank you for this opportunity to speak to you today.

Contrary to his "all of the above" energy strategy announced several years ago, President Barack Obama has now jumped on the "keep it in the ground" bandwagon that is currently being voiced by most of his environmental constituency. Over the past year he has vetoed the Keystone Pipeline, put limits on coal development on federally-owned land, and yanked the Atlantic offshore leasing program—all in the name of combating climate change.

Then in June of this year, the Environmental Protection Agency (EPA) finalized a rule requiring drilling companies to install new monitors to detect methane emissions during the production and transmission of oil and natural gas. The EPA estimates the cost of complying with the rule at $530 million annually by 2025. The agency is also expected to move forward with additional rules governing methane leaks from existing wells by the end of the year while at the same time initiating a data collection program on tens of thousands of oil and gas operation, an effort that could result in even more intrusive regulations in a few years.

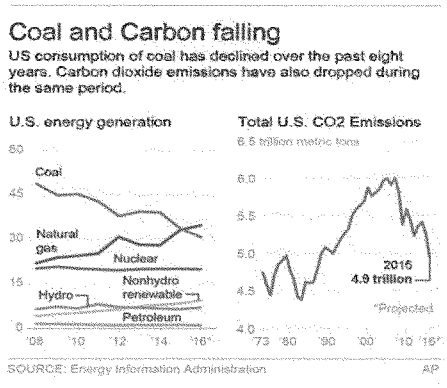
The White House justifies these new regulations by arguing that methane traps 50 to 75 times as much heat as carbon dioxide (CO2) in the atmosphere over a 20-year period, thereby contributing significantly to human-induced global warming. But if the goal is to significantly reduce greenhouse gas emissions (GHGs), including methane, the oil and gas industry is the wrong whipping boy.

Here are some facts. Methane releases from the oil and gas industry represent only about 3.4 percent of all GHG emissions, which reached a 25 year low last year. This is an astounding accomplishment considering the American economy is 75 percent larger than it was in 1990 while domestic oil and gas production has nearly doubled over the past decade. What's more, total U.S. methane emissions have dropped 15 percent since 1990. Emissions from fracked oil and gas wells have fallen 79 percent while natural gas pipeline leaks have been reduced by 94 percent.

It's true that methane emissions globally are still increasing. But a recent study by the National Oceanic and Atmospheric Administration (NOAA) finds that "the U.S. energy industry contributes little to the overall burden of global fossil fuel emissions." Rather, according to NOAA, wetlands and agriculture are the main culprits.

Studies by National Economic Research Associates (NERA) and other energy researchers have challenged assertions by the EPA that reducing methane leaks 45 percent by 2025, which is the Obama administration's target, will benefit the climate to the same degree as shuttering one-third of the world's coal-fired power plants. NERA concludes that the alleged benefits of its methane rules are "highly uncertain and very likely overstated" while an analysis by Energy in Depth finds that the rule would reduce global warming by a mere 0.004 degrees Celsius. Put differently, we could shut-in all American oil and gas production and the impact on climate change would be virtually zero.

Ironically, the oil and gas industry—not the EPA—deserves most of the credit for lower GHG emissions, in particular the substitution of clean-burning natural gas for coal in electric power generation (see chart below). A decade ago, coal plants provided 50 percent of the nation's electricity compared with 18 percent for gas. This year, coal's share will drop to 30 percent while gas will increase to 33 percent of power generation.



Acknowledging the environmental benefits of natural gas, the Intergovernmental Panel on Climate Change (IPCC) recently observed that an "increased and diversified gas supply is an important reason for a reduction of GHG emissions in the United States" while the International Energy Agency (IEA) contends that natural gas is a "valuable component of a gradually de-carbonizing electricity and energy system."

Regulation is never cost free, and the new methane rules are no exception. With oil and natural gas prices close to 10-year lows, producers and service companies laying off tens of thousands of workers, and bankruptcies rising, does it make sense to increase the cost of staying in business?

Costly new regulations on methane emissions from oil and gas production, processing and transmission are also unnecessary because the industry is adopting stricter controls on its own. For example, Southwestern Energy—the nation's third largest natural gas producer—is leading an industry group called One Future that aims to reduce methane leakage to less the one percent of natural gas production. To this end, Southwestern has upgraded pumps and compressors, deployed new tanks to capture methane that is vented by hydraulic fracturing, and replaced leaky gas-powered control equipment with solar panels and fuel cells. Southwestern is also participating in projects with the Environmental Defense Fund and several tech companies to test continuous methane detection systems using lasers, sensors and even drones.

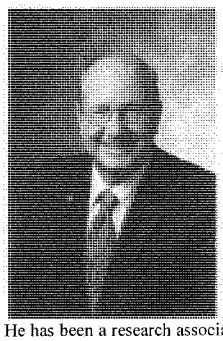
Southwestern Energy and other producers are not taking these steps because of environmental altruism but because they recognize that methane, the principal component of

natural gas, has economic value when it is captured and used to generate electricity, heat homes, and produce petrochemicals.

Energy policies and regulations should not be driven by environmental alarmists, which is clearly the case today, but rather by sound science and careful cost-benefit assessments. I hope that is one of the goals of today's hearing.

Thank you again for the opportunity to express my views before this committee.

Bernard Weinstein, Associate Director, Maguire Energy Institute



Bernard L. Weinstein is Associate Director of the Maguire Energy Institute and an Adjunct Professor of Business Economics in the Cox School of Business at Southern Methodist University in Dallas. From 1989 to 2009 he was Director of the Center for Economic Development and Research at the University of North Texas, where he is now an Emeritus Professor of Applied Economics.

Dr. Weinstein studied public administration at Dartmouth College and received his A.B. in 1963. After a year of study at the London School of Economics and Political Science, he began graduate work in economics at Columbia University, receiving an M.A. in 1966 and a Ph.D. in 1973.

He has taught at Rensselaer Polytechnic Institute, the State University of New York, the University of Texas at Dallas, and the University of North Texas. He has been a research associate with the Tax Foundation in Washington, D.C. and the Gray Institute in Beaumont, Texas. He has worked for several U.S. government agencies including the Presideut's Commission on School Finance, the Internal Revenue Service and the Federal Trade Commission.

Dr. Weinstein has authored or co-authored numerous books, monographs and articles on the subjects of economic development, energy security, public policy and taxation, and his work has appeared in professional journals such as *Land Economics, Challenge, Society, Policy Review, Economic Development Quarterly, Policy Studies Journal, and Annals of Regional Science.* His op-eds have been published in *The New York Times, The Wall Street Journal, The Washington Times, Investor's Business Daily, The Financial Times, The Los Angeles Times, The Hill* and a number of regional newspapers and magazines.

Dr. Weinstein has been a consultant to many companies, non-profit organizations and government agencies, and he testifies frequently before legislative, regulatory and judicial bodies. His clients have included AT&T, Texas Instruments, Reliant, Entergy, Devon Energy, Energy Futures Holdings, the Nuclear Energy Institute, the American Petroleum Institute, the U.S. Conference of Mayors, the Western and Southern Governors Associations, the Cities of Dallas and San Antonio, and the Joint Economic Committee of the U.S. Congress.

Dr. Weinstein was director of federal affairs for the Southern Growth Policies Board from 1978 to 1980 and served as director of the Task Force on the Southern Economy of the 1980 Commission on the Future of the South. From 1984 to 1987 he was chairman of the Texas Economic Policy Advisory Council and from 1987 to 1988 served as visiting scholar with the Sunbelt Institute in Washington, D.C. He is currently a panelist with the Western Blue Chip Economic Forecast. Dr. Weinstein is a member of the Dallas-Fort Worth Association for Business Economics and serves on the boards of directors of Beal Financial Corporation and AccuTex Investments, LLC. From 2011 to 2014 he was a Fellow with the George W. Bush Institute, and he is currently an Associate of the John Goodwin Tower Center for Political Studies at SMU and a Fellow of Goodenough College in London.

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Chairman BRIDENSTINE. Thank you, Dr. Weinstein.
Mr. Holstein, you're recognized for five minutes.

TESTIMONY OF MR. ELGIE HOLSTEIN,
SENIOR DIRECTOR FOR STRATEGIC PLANNING,
ENVIRONMENTAL DEFENSE FUND

Mr. HOLSTEIN. Thank you very much, Mr. Chairman. Chairman Smith, nice to see you again. And, Ranking Member Bonamici, Members of the Subcommittee, I'm very grateful for this opportunity to discuss the role of methane with you today as a potent greenhouse gas pollutant and the need for EPA's rules to guide the industry in minimizing those emissions.

Our scientific understanding of the extent of methane pollution and its effects has been growing steadily, and mostly in the last several years have we been getting a better scientific handle on the extent of the pollution and its impacts. But there is no question at this point that methane is a powerful and harmful climate pollutant.

As Ms. Bonamici mentioned, over the first 20 years following its release methane is some 84 times more potent than CO_2 in terms of the climate damage that it does. So while CO_2 is of concern and does represent a continuing long-term threat, methane drives near-term climate effects. The result is that 25 percent of the global warming we are experiencing right now is due to methane emissions, and that's why we need action to address both sides of that equation.

Across our economy, the oil and gas sector represents 33 percent of U.S. methane emissions, and it's the largest of all industrial U.S. sources. EPA's latest inventory estimates that in 2014 oil and gas industry operations released 9.8 million metric tons of methane into the atmosphere, and that was a 34 percent increase over their previous estimates. That amount of methane packs the same climate punch over the first 20 years after it's released as the CO_2 emissions for more than 220 coal-fired power plants. And 220 plants is more than half of the coal plants we have in this country.

But the good news is that doing something about methane pollution, including complying with methane—EPA's methane rules, can be accomplished at low cost using existing technology. ICF Incorporated did a landmark study in 2014 in which they found that a relative handful of specific remedial actions could yield a 40 percent reduction in methane emissions from the oil and gas sector at an average cost of about 1 cent per 1,000 cubic feet of gas produced.

As I mentioned, EPA's recent inventory reflected an increase of 34 percent over previous estimates, but we would suggest that that number is still understated because scientific evidence suggests that even that dramatic revision does not reflect the additional methane pollution represented by high random emissions coming from a small percentage of sites.

This kind of distribution in which large volumes are emitted from a relatively small percentage of sites is characteristic of methane leakage in the oil and gas sector. For that reason, leak detection and repair programs such as those required by EPA's rules

and under some state programs, are an essential part of addressing the methane emissions problems.

EPA's recently finalized new source performance standards for methane pollution build on successful regulatory frameworks that have been adopted over the last several years in some leading energy-producing States such as Colorado and Wyoming. So while we support EPA's action to control oil and gas sources of methane emissions from new and modified sources, we also strongly encourage the agency to keep making progress toward addressing methane emissions from existing sources. Again, according to ICF, nearly 90 percent of the oil and gas methane emissions in 2018 will have come from sources that were already in existence by 2012. Again, federal actions build on state initiatives.

Colorado's rules require leak detection and repair programs for all wells, both new and existing, conventional and unconventional. Altogether, the new rules will remove 100,000 tons of methane and 90,000 tons of smog-forming volatile organic compounds. That's equal to the emissions of all the cars and trucks in the State of Colorado today, year after year after year.

Now, I know that this subcommittee is deeply concerned about the potential cost to the industry of complying with state and federal methane rules, but the good news on this issue is not only that cutting methane emissions is generally very inexpensive but the cost of methane leak detection surveys is relatively low as well. Today, methane inspections can cost as little as $250, and of course one of the benefits of the EPA regulation is that it's already driving innovation in the private sector.

Today, there are 75 companies in 500 different locations in 46 States providing methane reduction services and support. Regulating methane emissions from both new and existing sources is an important and cost-effective step in stopping the worst effects of climate change.

Thank you for the opportunity to testify today, and I am happy to take any questions you may have.

[The prepared statement of Mr. Holstein follows:]

Testimony of Elgie Holstein
Senior Director for Strategic Planning, Environmental Defense Fund
Before the Subcommittee on Environment
House Committee on Science, Space and Technology
Regarding EPA's Methane Rules
September 15, 2016

Mr. Chairman and members of the subcommittee, thank you for this opportunity to discuss the role of methane as a climate-changing greenhouse gas pollutant and the need for EPA rules to guide the industry in minimizing those emissions.

Environmental Defense Fund (EDF) is a national environmental advocacy organization with a million-and-a-half members nationwide. Placing a strong emphasis on our core strengths of science and economics, we are dedicated to finding innovative approaches to solving some of the most difficult national and international environmental challenges. Whenever possible, we collaborate with private-sector partners, state and federal leaders, academic institutions and other environmental organizations interested in maximizing incentives for market-based solutions to environmental problems.

We recognize that the oil and gas sector is a key contributor to our nation's energy mix, but with that role comes the responsibility to minimize harmful impacts to our communities and to the environment. With the recent increases in recoverable oil and gas reserves, it is more important than ever that both the industry and the government commit to a cleaner and more sustainable energy future. Recognizing and addressing the causes and effects of methane emissions with respect to global climate change is one important step in fulfilling that commitment.

Our scientific understanding of the extent of methane pollution and its effects has been growing steadily. EDF has contributed to that knowledge base by engaging with over 100 partners from industry and academia in numerous scientific studies that have helped to better identify the extent and sources of methane emissions in the oil and gas sector. That work has been driven by our dual concern for the environment and for public health.

There is no question that methane is a harmful climate pollutant. Over the first 20 years following its release, methane is some 84 times more potent than CO2 in terms of the climate damage it does. While CO2 represents a continuing, long-term threat in the form of accumulated, long-lived and rising atmospheric concentrations, methane drives

near-term climate effects. The result is that 25% of the global warming we are experiencing now is due to methane emissions.

In addition, the Intergovernmental Panel on Climate Change has concluded that more than half of the warming in the next couple of decades due to current emissions will be from short-lived climate pollutants (based on present-day emissions data from various sources and GWPs in IPCC AR5).

Decisions made now about methane emissions will have a major impact on the rate at which the climate changes over the lifetimes of many Americans living now and spanning the next several generations. (For more details about the science underlying concerns about methane and other short-lived climate "forcers," please see the attached article from Science magazine.)

From both a science and a policy perspective, it makes sense – and we believe it is essential -- to address the threats from both climate-changing pollutants.

Across our economy, the oil and gas sector represents 33% of U.S. methane emissions, the largest of all industrial U.S. sources, according to EPA.

EPA's latest inventory, published in April of this year, estimates that in 2014, oil and gas industry operations released 9.8 million metric tons of methane into the atmosphere – 34% higher than previous estimates.

That's enough to meet the needs of over 7 million households. And, it packs the same climate punch over the first 20 years as the CO2 emissions from more than 220 coal-fired power plants.

The good news is that doing something about methane pollution – including complying with EPA's methane rules – can be accomplished at low cost, using existing technology. Moreover, as information about the specific sources of methane leakage continues to improve, prevention, detection and repair methods and technologies will also improve, bringing prices down even farther.

In any discussion about the costs of controlling methane, it is useful to start with ICF Inc.'s landmark 2014 study, in which they found that a relative handful of specific remedial actions could yield a 40% reduction in methane emissions from the oil and gas sector at a cost of about one cent per thousand cubic feet of gas produced.

While scientific evidence of the threats posed by methane emissions continues to mount, estimates of the extent of those emissions have risen dramatically. The U.S. oil

and gas industry emits on the order of 10 million metric tons of methane pollution per year, from thousands of sites across the country.

As I mentioned, EPA's recent update to its methane inventory reflected an increase of 34% over previous estimates. Yet, recent scientific evidence suggests, even that dramatic revision does not reflect the additional methane pollution represented by high, random emissions coming from a small percentage of sites. This kind of "fat tail" distribution, in which large volumes are emitted from a relatively small percentage of sites, is characteristic of methane leakage in the oil and gas sector. For that reason, leak detection and repair regimes, such as those required by EPA's rules and under some state programs, are an essential part of addressing the methane emissions problem.

One of the worst recent examples of methane leakage – indeed, one of the worst on record -- occurred during the multi-month disaster that began last fall when the Aliso Canyon facility in California leaked an astonishing 97,000 metric tons of methane. How much is that? – It is the equivalent climate impact of burning nearly a billion gallons of gasoline.

The significance of the Aliso Canyon disaster extend well beyond climate impacts, however. Nearby residents were sickened and thousands of people from the town of Porter Ranch were evacuated from their homes, as the disaster dragged on for more than three months. There are approximately 400 similar facilities nationwide, and Aliso Canyon powerfully demonstrates the need to develop state and federal rules that will prevent a similar disaster from happening again.

Among the many concerns raised by Aliso Canyon is the impact of leaks on public health and safety. According to the American Lung Association, emissions of greenhouse gases, such as methane, threaten the health of current and future generations. (December 2015 ALA letter to Administrator McCarthy.) In calling for EPA action to reduce methane emissions, they point out that "the nation has a short window to act to reduce those threats." They also emphasize that cutting methane emissions can provide immediate health benefits, including reductions in volatile organic compounds, which include gases recognized as hazardous air pollutants." Finally, ALA notes that limiting VOCs will reduce the amount of ozone, thereby reducing respiratory diseases and premature deaths.

EPA's recently finalized new source performance standards for methane pollution from the oil and gas sector represent a critical step towards minimizing these climate and public health impacts. These standards are based upon proven, highly cost-effective technologies and best practices that responsible companies are already deploying to reduce emissions. They also build on successful regulatory frameworks that have been

adopted over the last few years in leading energy-producing states such as Colorado and Wyoming. Among other things, these standards will require — for the first time — that oil and gas companies carry out semi-annual or quarterly leak inspections at new facilities in oil and gas production, gathering, transmission and storage; minimize emissions from newly completed hydraulically fractured oil wells; and deploy emission control technologies for devices like pneumatic pumps.

These common-sense protections will yield a safer climate for our children and cleaner air in communities across the country — avoiding over half a million tons of methane pollution each year by 2025, as well as over 200,000 tons of smog-forming VOCs and 3,900 tons of toxic air pollutants such as benzene. And they will do so with minimal impacts to the industry and to energy prices.

While EDF supports EPA's action to control oil and gas sources of methane emissions from new and modified sources, we strongly encourage the agency to keep making progress toward addressing methane emissions from existing oil and gas sources as well. According to ICF, Inc. nearly 90% of oil and gas methane emissions in 2018 will come from sources which were already in existence in 2012.

The Bureau of Land Management's recently proposed venting and flaring rule, which applies on federal and tribal lands, underscores the viability of applying many of these commonsense controls to both new and existing sources. We applaud that agency for taking action to minimize the waste of publicly owned resources, which will have important climate benefits as well.

These kinds of federal actions are built on a foundation of state initiatives that have already proven reducing methane from the oil and gas sector can be both effective and economical. In Colorado, we partnered with the state's three leading oil and gas producers to secure first-in-the-nation regulations to reduce methane and other harmful air pollutants from oil and gas operations. Some of the industry's largest operators supported the new rules because they understood both the availability of eminently cost-effective pollution controls as well as their responsibility to demonstrate environmental leadership and to reassure an increasingly concerned public.

The Colorado rules require leak-detection-and-repair programs for all wells – both new and existing, conventional and unconventional. The largest well sites will be inspected monthly. Unnecessary venting during well maintenance is no longer allowed. And so-called high-emitting valves will be replaced by low- or zero-emission valves. Existing storage tanks will have to meet new pollution limits as well as current federal limits applicable to new tanks. Altogether, the new rules will annually remove 100,000 tons of methane and 90,000 tons of smog-forming volatile organic compounds, equal to the

emissions of all of the cars and trucks in Colorado today. In a recent study by the Conservation Economics Institute on the Colorado methane rule, findings show that seven out of ten producers believe that the benefits of regularly checking equipment for leaks outweighs the costs.

Pennsylvania has released a blueprint for strong methane rules that would regulate both new and existing sources.

In Wyoming, where air quality has been severely compromised in a portion of the state by rapidly expanding oil and gas operations, finalized rules for the Upper Green River Basin, where production activities were contributing to ozone non-attainment as bad as in some cities. This program includes quarterly leak-detection-and-repair inspections for new and existing oil and gas emission sources.

Leaders in Wyoming recognize that you don't solve the problem if you don't tackle existing sources. Recently, rules were finalized in Wyoming improving requirements for new sources statewide. The state's Air Quality Advisory Board unanimously voted to incorporate by reference EPA's new source standards just last week.

In Ohio, Governor Kasich supported changes to the general permit for oil and gas operations. The changes require leak-detection-and-repair program for volatile organic compounds from new, unconventional wells --like Wyoming and Colorado, requiring quarterly inspections using an infrared camera or handheld hydrocarbon analyzer.

I know that this subcommittee is concerned about the potential costs to the industry of complying with state and federal methane rules.

The good news on that issue is not only that cutting methane emissions is generally very inexpensive, as I noted above, but that the cost of methane leak detection surveys is relatively low as well. Today, methane inspections can cost as little as $250. And of course, one of the benefits of the EPA regulation is that it is already driving innovation in the private sector, which promises to bring those costs down even more.

So, demand for inspection services goes up, accompanied by technology innovation (and with it, jobs), followed by declining costs. Today, there are 75 companies in 500 different locations across 46 states providing methane-reduction services and support.

Conclusion

Natural gas is, and will remain for the foreseeable future, an important part of our nation's energy mix. The natural gas revolution in America can make a positive

contribution to a cleaner environment, but only if gas development is based on reasonable rules to ensure that its more damaging impacts are limited.

As we manage our nation's bounty of oil and gas, it is important to get the rules right. As mentioned above, doing so will not only help minimize adverse environmental impacts, it is an essential ingredient in building public trust and confidence in the ability and commitment of the industry to reducing negative impacts on public health.

Regulating methane emissions – from both new and existing sources – is an important and cost-effective step in stopping the worst effects of climate change. Other measures are needed as well, including legislation to put a price on carbon that will reflect the full costs of carbon pollution, while simultaneously inspiring new technologies to reduce those impacts and to stimulate further deployment of cleaner alternatives.

Thank you for the opportunity to testify today, and I welcome any questions you may have.

Elgie Holstein

Elgie Holstein is Senior Director for Strategic Planning at Environmental Defense Fund in Washington, DC. Prior to joining EDF in 2009, he was co-director of the DOE presidential transition team.

He has held a number of senior positions in government and the private sector with a focus on energy, natural resources, and environmental policy.

His government service includes:

- Associate Director for Natural Resources, Energy and Science in the Office of Management and Budget;
- Special Assistant to the President for Economic Policy at the National Economic Council;
- Deputy Undersecretary and Assistant Secretary at the National Oceanic and Atmospheric Administration; and
- Chief of Staff at the U.S. Department of Energy.

Mr. Holstein has served as a consultant to DOE, including serving on an advisory committee of Sandia National Laboratories. He also has been an advisor to local governments on water and energy matters.

Earlier, Mr. Holstein served as Energy and Environment Staff Director for the National Conference of State Legislatures, worked as a congressional staff member specializing in energy and environmental policy, and headed a national consumer financial education and advocacy group.

Chairman BRIDENSTINE. Thank you, Mr. Holstein.
Mr. Ventello, you are recognized for five minutes.

TESTIMONY OF MR. ANTHONY J. VENTELLO,
EXECUTIVE DIRECTOR, PROGRESS AUTHORITY

Mr. VENTELLO. Thank you, Mr. Chairman, Committee Members.
My name is Anthony Ventello. I'm the Executive Director of the Progress Authority. We're an industrial development and economic development agency in the northern tier of Pennsylvania.
I live, work, and have raised a family in the heart of the Marcellus Shale formation. We rank first, second, and first in statewide shale gas, both in both Bradford and Susquehanna Counties, over 5,700 wells, 2,200 drilled, 6.5 billion cubic feet per day of production, representing about 245,000 jobs and $33 billion of investment.
The answer lies in vertical integration, utilizing the gas. Distribution is critical. Please could I have two slides?
[Slide.]
Mr. VENTELLO. Distribution is critical.
Next slide.
[Slide.]
Mr. VENTELLO. One of the issues is at a simple very low level effect is having some of the most prolific wells in the world or 30 MMcf, there was no local distribution. Nobody could have access to the gas. We were—we've been able to pipe both schools—actually, in a situation where a school actually has wells on it, they were able to do a postsecondary school from the standpoint of bringing clean natural gas to that location.
Two hospitals had been built in that region, both having natural gas services. In fact, some of the drilling companies have participated in the development of that. And you can see the immense amount of investment and jobs that have been created, 51 million and 35 million and several hundred jobs as a result of it.
Infrastructure, next slide, please.
[Slide.]
Mr. VENTELLO. Infrastructure has been critical. We're now looking at—in both virtual and new pipelines where new pipelines have been curtailed, there's been several new virtual pipelines being developed along interstate corridors both with LNG—liquefied natural gas—and CNG—compressed natural gas—but it's—we have to get the gas to locations to be utilized and marketed.
Under the energy generation, next slide, please.
[Slide.]
Mr. VENTELLO. I just toured two brand new facilities in our region. One is an 829 megawatt combined cycle facility, Panda power station, about 900 million of new investment, eliminating oil and coal facilities, as well as to your—the smaller facility, 20 megawatts, there's seven proposed in our area. I've just toured the second completed one, but they also represent about 20 million in jobs created along with those.
One of the interesting elements is that combined heat and power has been a massive undertaking, and a lot of our larger facilities both in education, industrial development, or manufacturing, and

as well as hospitals have been getting involved in combined heat and power projects under construction.

In the instance of hospitals, you're seeing one mainly only because of medical record demand now with the, you know, increased automation. Cornell University, GTP, and Procter & Gamble, two of which I want to identify, but again, substantial investment, substantial support of job creation.

And one I want to identify for you is a 30 megawatt combined cycle station that's at Cornell University. They're very proud of this. I toured this facility. Keep in mind it has substantial support of over 12,000 employees and 21,000 students, and it's an anti-natural gas institution. They're very proud of that facility.

Infrastructure along the lines of CNG, we have both public fueling stations, compressed natural gas stations, private as well as public transportation is now being funded with—or fuel, excuse me, with compressed natural gas.

Next slide, please.

[Slide.]

Mr. VENTELLO. Industrial utilization has led to a lot of utilization and innovation with natural gas. Over 5,500 local jobs are being supported with natural gas.

We have strong manufacturing with natural gas in an effort to re-shore manufacturing into the United States is critical upon having cheap, clean, cost-effective natural gas available.

A worldwide example, I claim this is the worldwide example of natural gas utilization, and there's not a better example of it. Procter & Gamble has about 1,500 acres. They have the luxury of unconventional drilling on their site. They have a net zero cost for both energy generation, thermal demand, and of course they call it tri-generation. Now, they're a paper producer. They use hot air, which is usually a waste produce from combined heat and power but supporting over 3,000 employees at that location.

Gas to liquids, this is an innovative project. Most people don't realize this has gone on—global tungsten, GTP in Towanda, Pennsylvania, has—one of the largest users of hydrogen in the United States. They've now—they—most of their hydrogen came—next to NASA, most of their hydrogen came from both the Gulf States and Canada, and now they produce and crack their own hydrogen at that particular location, about a $15 million investment.

We also have gas-to-liquids projects being proposed with regards to clean diesel fuel, unleaded gas, wax, lube oils, and they're moving along because of the opportunity with gas.

This project I think I need to identify to you. This is a company that's using produced water flow back, and they're actually recycling it and crystallizing it and utilizing those crystals now, breaking them further down into chemicals to be used in industry throughout the region.

I want to talk in terms of money that's being invested back into the local counties, Act 13, about 70 million between two counties for public safety. I want to highlight environmental conservation, site development, and housing. All of those are being invested in in our area.

Here's an example of two housing projects, both elderly—that was a burned-out furniture store at—in the upper area that's now

about 40 units of residential elderly housing and of course moderate-income housing at the lower level, both naturally gas-served.

Locations are being developed substantially by the fact that we have compression stations, locations with pipelines. There are target locations for vertical integration throughout our region, and we've identified those and are working with companies to try to locate there.

[Slide.]

Mr. VENTELLO. This is just a slide to show you all the elements that get involved in natural gas from the standpoint—all the features from the standpoint of well pads, water withdrawal locations, compression, and pipelines.

One thing I think is extremely critical is the fact that agricultural production is on the rise in our area. As a result, in 2008 it was on the decline. The Marcellus Shale, since then, it's been on an incline. And if I can just summarize it by saying natural gas has been a complementary land use and has kept land in large parcels, which is conducive to agriculture and maintains a rural way of life. I can—all aspects of—soybean, beef, swine, egg production, and niche farming has been on the rise because farmers now have some income to reinvest in the farm.

And I just want to summarize by saying that increased regulation will reverse the established initiatives that we have in environmental benefits, economic investment in jobs, and energy independence with overregulation.

I want to thank the committee for the opportunity.

[The prepared statement of Mr. Ventello follows:]

Testimony
September 15, 2016
Congress of the United States, House of Representatives
Committee on Science, Space and Technology

Progress Authority Natural Gas Utilization Value-Added Presentation

Presented by Anthony J. Ventello, Executive Director

INTRODUCTION

Bradford and Susquehanna Counties Shale Gas Production

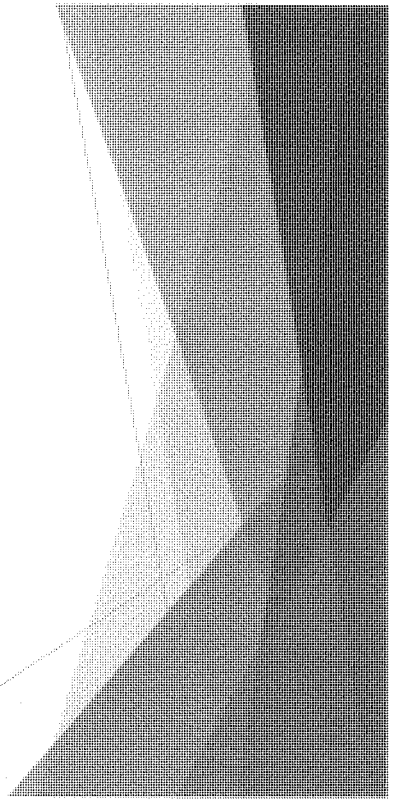
Progress Authority
IDC/IDA

- Rank 2nd and 1st in statewide shale gas production.
- Over 5,700 wells permitted; 2,200 drilled.
- 6.5 bcf of natural gas production per day.
- 245,000 jobs impacted
- $33 billion investment since 2007.
- Future investment lies with vertical integration.

What low-cost gas does

DISTRIBUTION

The Root of Vertical Integration



"PERFECT IRONY"

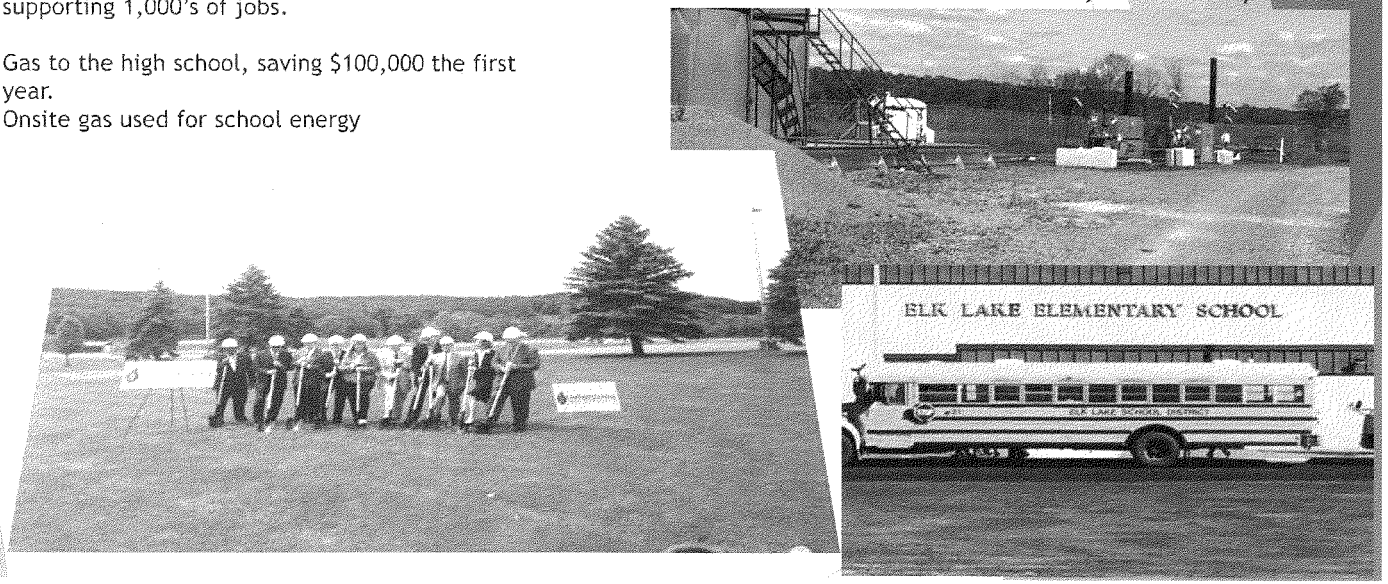
Leatherstocking GAS COMPANY

Local Gas for Local People

Susquehanna County - some of the most prolific wells in the world - no local distribution.

To date, private investment of over $20 million, supporting 1,000's of jobs.

Gas to the high school, saving $100,000 the first year.
Onsite gas used for school energy



Endless Mountains Health Systems – Susquehanna County

- $51 million investment
- 182 Jobs

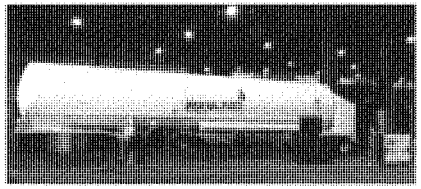
New Guthrie Troy Facility – Bradford County

- $35 million investment
- 130 jobs
- Existing but value-added

Natural Gas Served Large Energy Savings

INFRASTRUCTURE DEVELOPMENT

Balance of vertical integration and movement

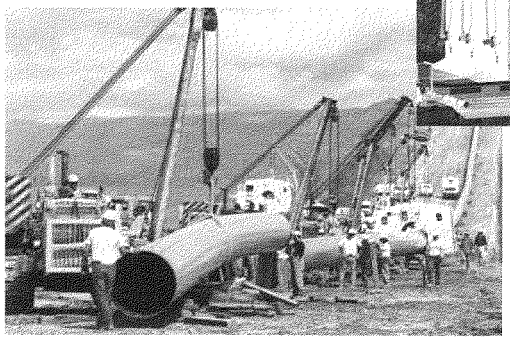


REV LNG

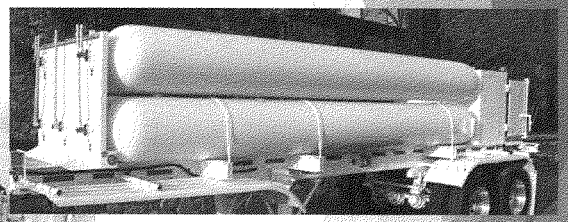
- $10 million investment
- Non-piped distribution
- New England Market Demand
- 600 times concentration

Represents $100's of millions of investment to "Move the Gas"

Pipelines – real and virtual



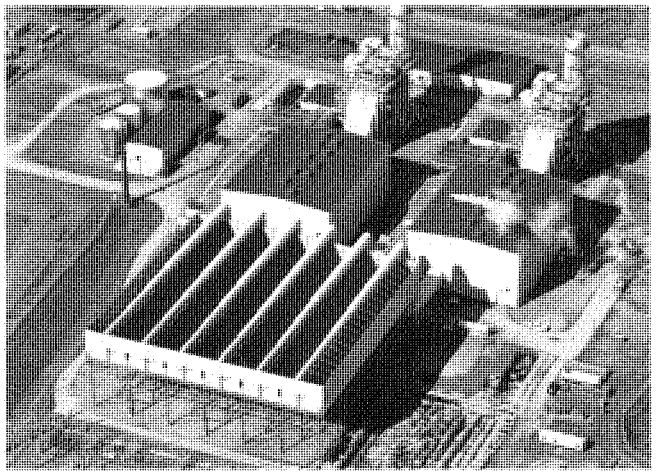
Tube tankers



Pipeline delays lead to CNG and LNG trucking terminals

ENERGY GENERATION

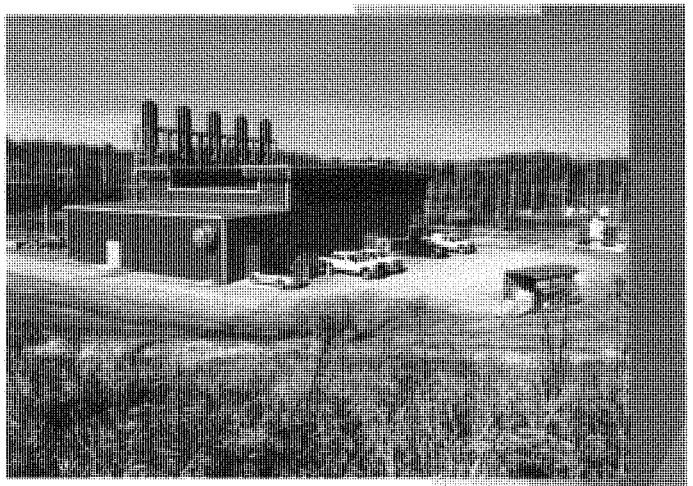
Broader Market Impact for Utilization



Panda Power Station, Asylum Township

- 829 megawatt combined cycle generation
- 40 - 45 full time jobs; 300 - 600 during construction
- $900 million investment x 2
- Sister Plant - Patriot, Lycoming County $900 million
- Others proposed in the PJM system

Panda Power Funds



IMG Energy

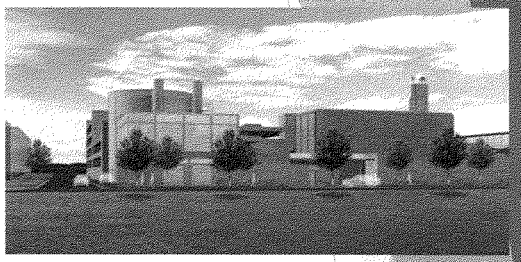
- 20 mw natural gas fired power generation facility
- $20 million in new investment
- 7 sites in 2 counties; 2 completed

IMG MIDSTREAM

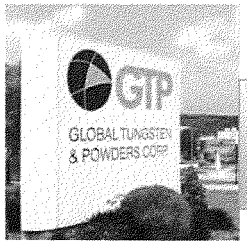
Combined Heat and Power (CHP)

- Electrical Generation/Steam/Thermal Demand
  - GTP (Global Tungsten Powders) 7.5 mw, $20 million, 500 jobs
  - Cornell University in NY (ironic) 30 mw, $180 million, 12,800 jobs
  - Proctor & Gamble - Model Project; Worldwide Example:
    - 30 mw, $50 million, 3,000 jobs
    - "Tri-generation"

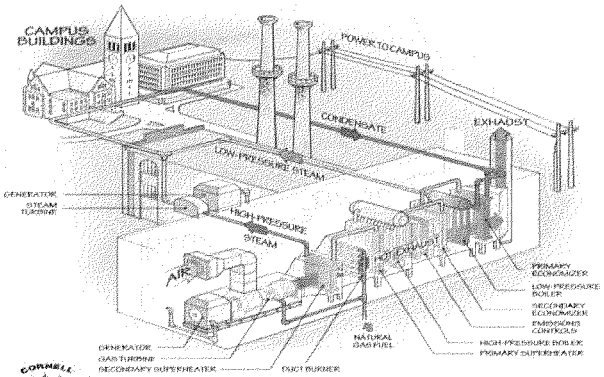
- *Cheap Fuel Stock Rising Electrical Pricing Make Proforma Payback Feasible*
- *Pennsylvania - Reverse metering advantage*



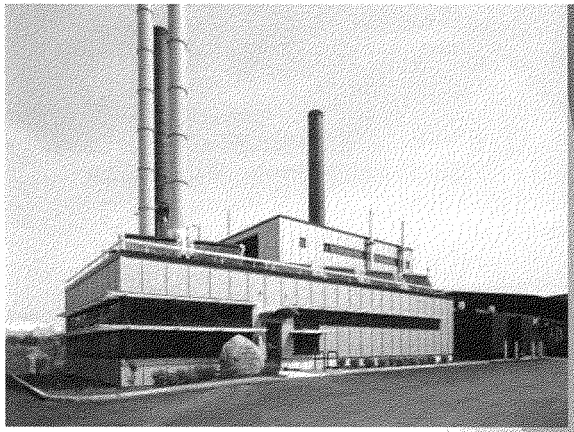
- Guthrie Healthcare 2 mw, $6 million, affects 5,000 jobs
- Act 129 Rebate; ACE Grant
- 5 - 7 year Payback
- **Reason: Medical Record Energy Demand**



- Approximately $10 million in investment
- Supports 500 jobs
- $2 million rebate - Act 129
- Power buyback



Combustion Turbine with Heat Recovery Steam Generator



Cornell University Combined Heat and Power

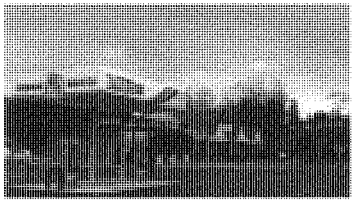
- Supports 12,842 Employees
- 21,600 Students
- Over 300 Buildings Serviced
- $180 Million Investment Made
- Anti-Natural Gas Positioning; NYS Moratorium
- *NYS Converting to Natural Gas Generation Faster than its Sister States*

- Conversion from Coal - Built in 1922; 65,000 tons of Coal Per Year - positive environmental impact
- Two 15 megawatt generators
- 77% Operating Efficiency

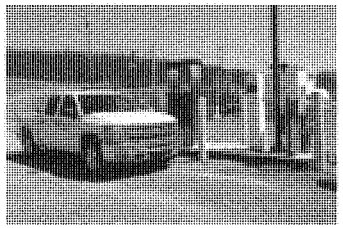
CNG
(Compressed Natural Gas)

CNG VEHICLE UTILIZATION

CNG Fueling Stations



Private CNG Fueling Stations

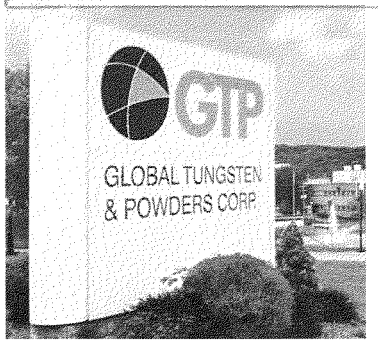


- *Vehicles*
- *Trucks*
- *Compressions Units for well completion*

Public Transportation

INDUSTRIAL UTILIZATION

Has Led to Innovative Uses



JELD-WEN WINDOWS & DOORS

MASCO CABINETRY

Leprino Foods

Cargill

150 years of helping the world *thrive*

Procter&Gamble

Clean
Efficient
Abundant

5,500 local manufacturing jobs supported by natural gas

DUPONT

Towanda Metadyne

Low cost
Feed Stock

Energy is at the Top of Common Concerns

Multi-National Companies

Millions of CF/day Used

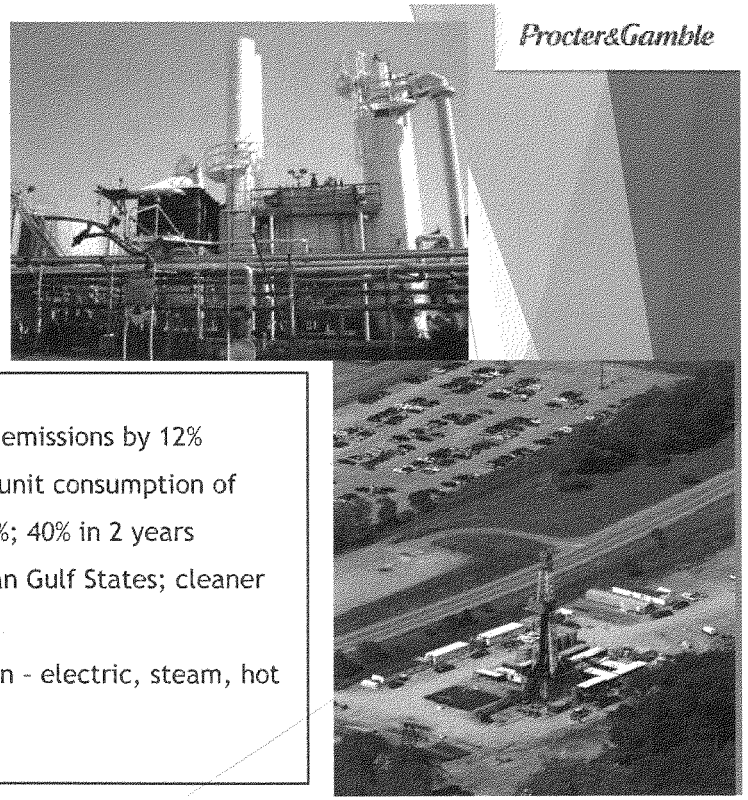
Worldwide Example of Vertical Integration: Procter & Gamble Mehoopany Wyoming County

Marcellus Gas Utilization

- Paper Manufacturing Site
- 3,000 Employees
- Energy intensive
- Unconventionally drilled on 1,400 acre campus
- Off the grid sell 10 - 20 mw back
- Use 10 bcf/year; excess to interstate pipeline

Environmental

- Reduces CO2 emissions by 12%
- Reduced per unit consumption of energy by 30%; 40% in 2 years
- Gas purer than Gulf States; cleaner emissions
- Tri-Generation - electric, steam, hot air



GTL
(GAS TO LIQUIDS)

Global Tungsten Powders
Towanda Borough and Township, Bradford County

- One of the Largest Users of hydrogen on the East Coast next to NASA
- Sintering metal - purge furnaces
- Partnering Air Products and hydrogen facility
- Thermal Cracking of natural gas to make hydrogen used in manufacturing
- Previously Gulf States/Canada - Katrina shut down
- 500 employees

- Several Companies investigating sites, products and investments
- Fuel Stock Never Cheaper vs Competition with Crude Oil Prices and High Cap Expenditure
- Sites Evaluated in Bradford and Susquehanna Counties
- Hundreds of Jobs
- Hundreds of Millions in Investment
- Several New Proposals

Eureka Resources

Standing Stone Township, Bradford County

- Value-added from produced water
- Crystallization
- Downstream products
- Road Salt
- Environmentally beneficial; recycle water and ultimately crystalize for chlorides

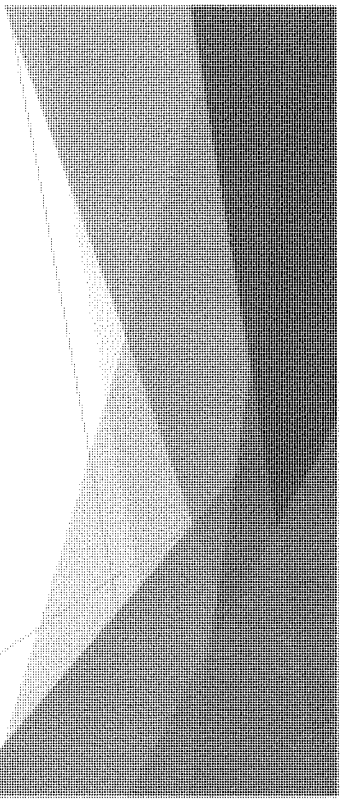
- 40 Employees
- $30+ Million of Investment
- Broader Market Uses for Chlorides

HOUSING AND DOWNTOWN REVITALIZATION USING SHALE GAS REVENUE RESOURCES

Act 13 Natural Gas Impact Fees

Providing Tremendous Economic Benefits

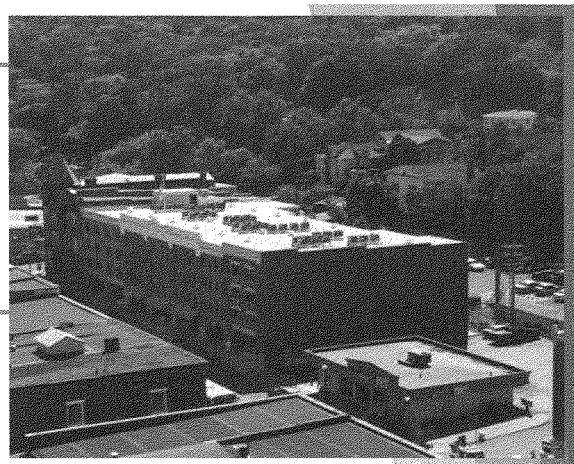
- $70 million investment locally total amount between the 2 counties.
- Sample uses via local decision making:
  - Public Safety
  - Infrastructure Development
  - Recreation
  - Environmental Conservation
  - Tax stabilization
  - Site Development
  - Housing

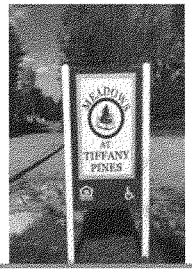


HOUSING

TOWANDA TERRACE

- 400 Block Revitalization
- Bradford County, Towanda Borough
- Burned out furniture store revitalization
- 4 story commercial with 39 units of residential
- 230 space parking garage developed
- $15 million in investment
- Natural Gas Served





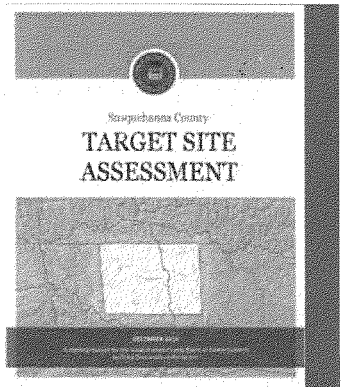
- Susquehanna County, Bridgewater Township
- *Meadows at Tiffany Pines*
- 40 Units of Housing - Completely Occupied
- $11 million in investment
- Natural Gas Served

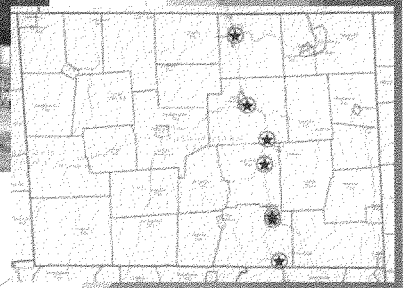
LOCATIONS

Where It Can Happen Downstream:

- Site near interstate or substantial midstream
- Liquid distribution lines for export of products from site
- Rail served
- Infrastructure:
  - Power/transmission lines
  - Sewer
  - Water
- Route 81 Interstate Corridor Analysis
- Target site assessment
- Energy corridor development

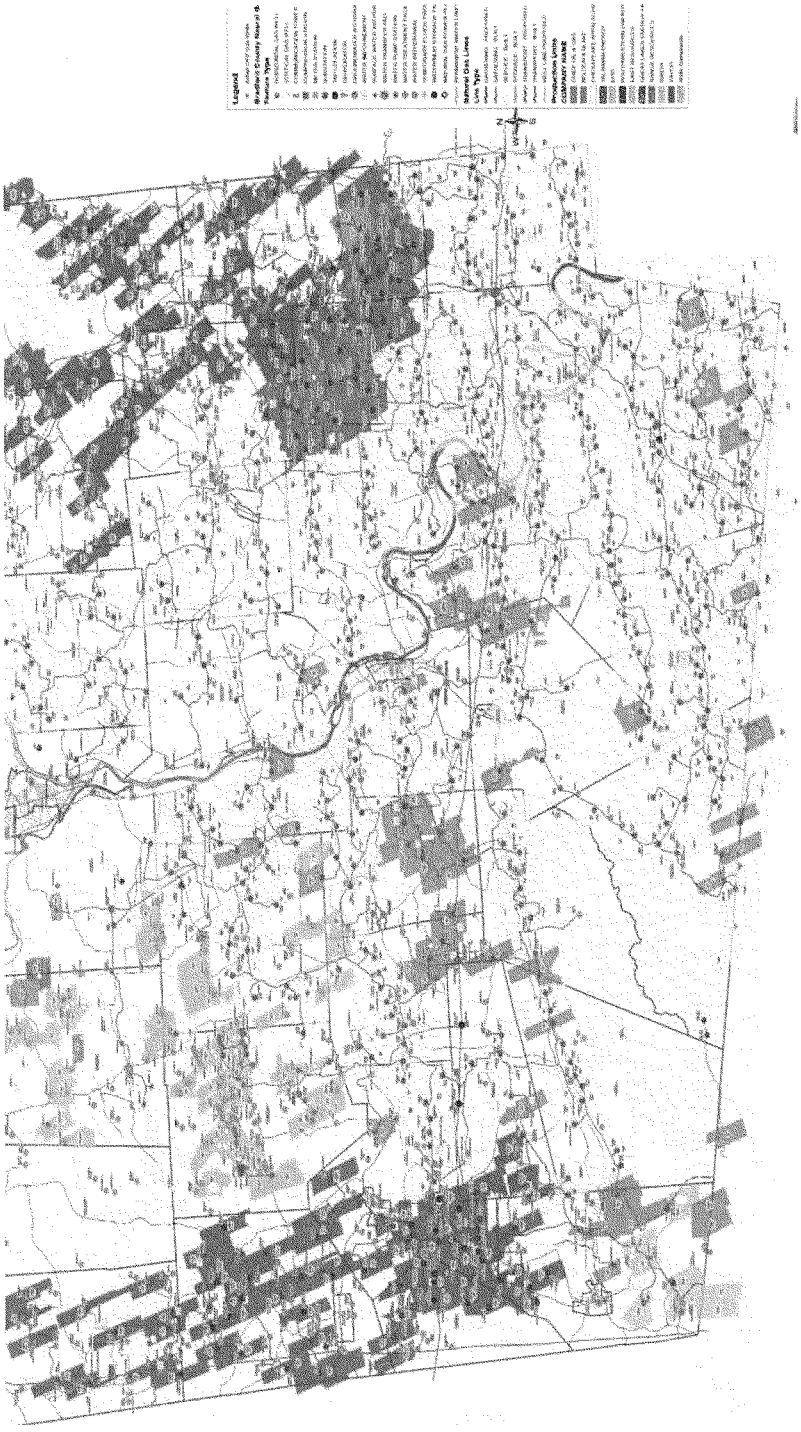
Liberty Compression Station





Route 81 Corridor, Susquehanna County

*Support the Development of the Keystone Energy Enhancement Act (KEEA Tax Abatements)



AGRICULTURAL PRODUCTION ON THE RISE

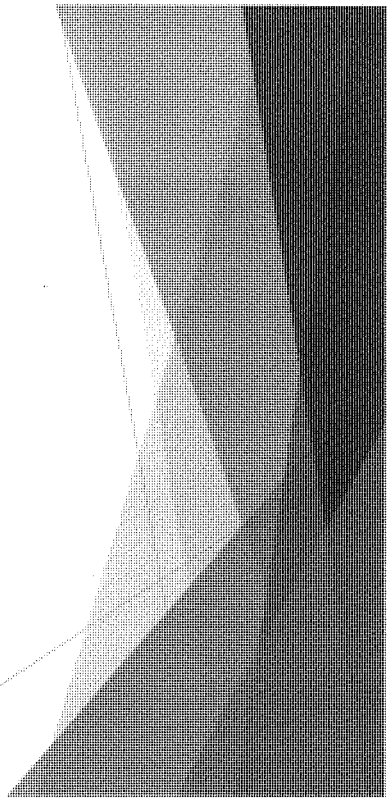
- Recent data from the Penn State Agricultural Extension and USDA Nation Ag Statistics are soaring
- 2001 to 2008 Dairy Cow Numbers Declining
- 2008 to date (Marcellus Gas Development Started) Cattle numbers stabilized
- Natural Gas Provided Income to Farmers to Reinvest in the Farm (purchase new equipment, building improvements and additional farmland) (abundant water resources and market proximity)
- Bradford County Amongst the Top Ten (one of the top two in dairy) Producers with Large Farms and the Other Nine Have No Gas Wells - Southern Area of State (no shale)
- Increases in Corn, Soybean, Beef, Swine, Poultry, Egg Production, Niche Farming, Maple Syrup, Orchards, etc.
- ***Natural Gas Has Been a Complimentary Land Use, Has Kept Land in Large Parcels which is Conducive to Agriculture and it maintains a Rural Way of Life.***
- It Also has Enhanced Tourism and Recreation.

FUTURE IMPACTS LIE WITH VERTICAL INTEGRATION OF NATURAL GAS NOT MORE REGULATION

- Increased production of natural has reduced the reliance on fuel oil and coal, thus reducing the carbon footprint.
- The natural gas industry has utilized best available technology, increasing production by 250% and emissions by 85%.
- We must create more opportunities to market gas and emissions become less of a concern. (Move the gas)
- The natural gas industry is self-enforcing green completions, eliminating venting. New gas wells are not the traditional leakers.
- It's all about a balance between investment for production and environmental controls. Zero emissions could be achieved, but at what cost to existing positive environmental protection trends, and the benefit of independent, clean, low-cost fuel to our nation.

ENVIRONMENTAL BENEFITS BUSINESS DEVELOPMENT

- Natural Gas is clean, low-cost energy and reduces emissions
- Business opportunities resulting in substantial investment and jobs
- Natural gas is the reason for low fuel oil pricing
- Reduces crude oil consumption
- Quad O regulations will negatively impact the advancements made in shale gas development investment and jobs



Thank you to the Committee on Science, Space, and Technology/
Subcommittee on Environment

Mr. Ventello is Executive Director of the Progress Authority, a Pennsylvania state-certified economic development provider. The Progress Authority provides economic development services for all of Bradford and Susquehanna Counties in Pennsylvania by contract. He has been involved in all aspects of economic development from project management to financing.

Mr. Ventello, with his planning and project management experience, has been directly involved in the development and financing of business development projects, infrastructure, and community development as public private partnerships to leverage investment and employment enhancement. He maintains a strong relationship with public officials at the local, state and federal level. Mr. Ventello also oversees a multi-million dollar revolving loan fund utilized to leverage private business investment.

The development of the Marcellus Shale gas play has dramatically impacted the Authority's jurisdictional counties. Mr. Ventello has gained broad knowledge of the economic and community impacts by traveling to Texas and Western Canada, New Mexico and recently Arkansas in an effort to educate and prepare for these impacts. Having experienced the last three years in the Marcellus development, he is able to report actual findings, impacts and experiences on Bradford and Susquehanna Counties, which have had the most natural gas wells drilled and permits requested in the Marcellus formation. Mr. Ventello has worked closely with natural gas drilling companies and their service providers to facilitate development and value-added resource utilization.

Prior to becoming the Progress Authority's first director in 1993, Mr. Ventello was director of the Bradford County Planning Commission form 1985 – 1993. He has a BA in geographic and regional planning from Mansfield University. He also holds an MA in public administration from Marywood University. He holds an American Economic Development Council certification from Penn State University.

Mr. Ventello resides in Franklin Township with his wife Trudy and has three children, Christine, Martine and Anthony.

Chairman BRIDENSTINE. Thank you, Mr. Ventello.

I'd like to thank all of the witnesses for their testimonies. Your written testimonies will be made part of the record. So even though this might be a short hearing, we have all of your information here with the committee.

Members are reminded that committee rules limit questioning to five minutes. I'll recognize myself for the first five minutes.

Dr. Weinstein, you're an economist. Do the benefits of the methane rule outweigh the costs, and can you explain?

Dr. WEINSTEIN. I don't believe so. I think there are costs that are currently unaccounted for and typical, you know, EPA cost-benefit analysis. But don't misunderstand me. I think, you know, methane releases are a serious environmental issue. I just believe there are better ways to deal with these issues.

I actually attended a seminar two days ago. It was actually a webinar, and it was sponsored by Stanford University and Resources for the Future. They made some very good points. And actually, Mr. Holstein mentioned one of them. The huge amount of methane release comes from what are called super-emitters. Well, I don't believe a kind of blanket regulation that would apply to, you know, all producers of natural gas, oil, transmission companies, what have you makes any sense if we can—you know, if there are, you know, targeted areas that can be addressed in terms of controlling emissions.

You know, there are a number of other specific areas that I think can be dealt with a lot more simply than passing a new slew of federal regulations. Another source of omissions is orphan wells. The States have traditionally done—dealt with orphan wells and any emissions associated with that.

We also have some old cities in the Northeast where there are pipelines that are leaking methane. I don't see where, you know, EPA has a role to play there. It makes a lot of sense for the cities and the States to initiate policies and take steps, along with the distribution companies, to replace those old lead pipelines. And that is going on.

So on balance I think what's being proposed in terms of new regulations from EPA on methane emissions, that the costs overall are going to far exceed any benefits.

Chairman BRIDENSTINE. As far as when you think about the cost and the benefit regarding our impact as one country in the entire world, does that change the calculus?

Dr. WEINSTEIN. I would put it this way. If the rest of the world were doing what we're doing in terms of both, you know, regulatory and private policies towards reducing greenhouse gas emissions, that would do a lot more to address climate change concerns than just what we do in the United States. As I showed in those two slides, you know, with little—how should I say—little impact from regulations per se, we have seen a tremendous drop in CO_2 emissions. We've seen a drop in methane emissions as well.

And I go back to the fact that we're not a stagnant economy. We're a growing economy. We're almost as—twice as large as we were 20 years ago. We've had 100 percent increase in oil and gas production, and yet emissions are falling. So the industry must be doing something right.

Chairman BRIDENSTINE. Mr. Milito, I wanted to get you on the record. Could you please describe the technological advances that the industry has made to reduce methane emissions?

Mr. MILITO. Yes, there are several. I think the first one you look at is what we call reduced emission completions, also called green completions. And this is an industry of solutions, and we understand that methane is a main component of natural gas so we want to capture it. We want to sell it, and we want to put it into the market. And one of the technologies that have been——

Chairman BRIDENSTINE. Can you make sure your—is your mike on?

Mr. MILITO. Sorry.

Chairman BRIDENSTINE. Okay.

Mr. MILITO. Appreciate that. I was talking about how the industry is an industry of solutions, and when we—when we're looking at an issue like methane, we're looking at the primary component of natural gas. It's the product that this industry sells, every incentive to make sure we're capturing it. And one of the areas that we realized we need to be proactive was when we're done with hydraulic fracturing and putting the well into production, the period called completion so we put together equipment and machinery to make sure that that process doesn't result in venting of gas, venting of methane, and that we're actually capturing it and using it for onsite fuel or for putting it into the market.

Other examples are reduction in the use of pneumatic valves and controllers that utilize natural gas and sometimes vented off, taking those away from the equation or moving to lower-venting ones, eliminating emissions from storage tanks, and the list goes on. But the idea here is that we are an industry that has been very active in deploying these technologies well before EPA put any regulations forward. And I would say that the EPA regulations are in many respects a lagging indicator of the industry because they're based upon technologies the industry has proactively developed.

Chairman BRIDENSTINE. Now, when you think about the study I mentioned earlier from Energy In Depth, we're talking about a change in global temperatures of .004 degrees Celsius over the next 84 years. Does that assume that the technological advances that are currently being made are not implemented or are implemented?

Mr. MILITO. Well, I think there's different ways to look at it. One way to look at it is understanding U.S. overall GHG emissions, of which methane constitutes ten percent, of which U.S. oil and gas methane emissions are about four percent. So think about that. We're talking about four percent of total greenhouse gas emissions, of which these rules are intended to maybe get 40 percent.

So you're—we're not talking about fractions of U.S. greenhouse gas emissions that these rules are intended to go after, yet at the same time, it's unclear if they're going to provide any appreciable benefit beyond what the industry is already doing. So we're adding tremendous costs that could be ultimately applied to a million wells, ultimately impacting the consumer in a very negative way because when our supply goes down, what happens to prices? The pressure is upward on prices. So we've got a very—we've got to question the types of actions when we're talking about fractions in the overall scheme of things.

Chairman BRIDENSTINE. Copy that.

I'd like to recognize Ms. Bonamici for five minutes.

Ms. BONAMICI. Thank you, Mr. Chairman.

Before I begin my question, I just want to comment on the opening statement of the Chairman. There was a citation to a NOAA study for the premise that the U.S. energy industry contributes little to the overall burden of global fossil fuel emissions. I'm a little concerned about the attribution of that comment because the NOAA study did not separate out United States from global emissions. So we're just for the record going to be following up to—with NOAA and correcting—putting any correcting information in the record.

Mr. Holstein, we talked a little bit about Aliso Canyon and how alarming that was and the thousands of people who had to evacuate and many became ill, and I know no one wants to see that kind of incident repeated. So would you please talk a little bit about what can be done to prevent similar incidents in a newly constructed facility? And importantly, will you please address the notion that's come up both in some of the statements from the dais but also in some of the testimony that voluntary efforts will be sufficient? Can you address that issue? Will voluntary efforts be sufficient without the EPA's involvement? Thank you.

Mr. HOLSTEIN. Certainly. Thank you. Aliso Canyon was a terrible tragedy, and I know your question was—is about new facilities of that kind, but we should note that there are 400—some 400 similar facilities all around the United States, and so we do need to be concerned about the existing facilities as well.

But with respect to both those and especially a new facility, the single most important thing to address in the construction of a new storage facility would be well integrity. And now, typically, these facilities make use of old oil and gas—depleted oil and gas fields in order to re-inject natural gas into those fields for long-term and sometimes short-term storage also in order to help meet spikes in demand that may occur during a heating season, for example, and—or for sudden surges in demand for electricity in the summertime.

So the first step, of course, is well integrity, to make sure that you've got the well constructed correctly. The second category of actions you want to take is to have a leak detection and repair set of protocols so that you see what's happening so that you can get a handle on these problems before they become a 3- or 4-month disaster requiring thousands of people to be evacuated.

And indeed, just 2 days ago, the company responsible for that leak did agree to a comprehensive new set of leak detection and repair protocols in their legal discussions or negotiations with the county. The State is still developing their case, but I think the fact that there is this focus on using the new leak detection technologies that are becoming available is instructive for the larger issues relating to methane.

Ms. BONAMICI. And what is your response to the suggestion that the industry can address this issue without regulation?

Mr. HOLSTEIN. If we look at the scale of the problem, which I—which has been detailed by EPA's recent inventory showing a 34 percent increase over the previous estimates, but in particular if

we look at the power of the methane molecule, it's an enormously powerful, nasty climate actor, and as you stated, 84 times more powerful than a molecule of carbon dioxide. And that—what that really means is we can't afford to wait for the industry to play catch-up with the science.

And part of the problem that the industry has—Dr. Weinstein is correct as far as he goes in saying that these random events are significant, but the emphasis I have to place is on the word random. You—a lot of this is counterintuitive. You can't simply take—make an assumption that old facilities are going to leak more than new facilities or the other way around, enormously random and that's why you need comprehensive leak detection.

Ms. BONAMICI. And can you talk a little bit about—you mentioned Colorado. They were successful in developing——

Mr. HOLSTEIN. They were.

Ms. BONAMICI. —regulations and how is that working in Colorado?

Mr. HOLSTEIN. Oh, it's working spectacularly well, and the best example I can give you of that is the fact that they've removed pollutants from the air there as a direct result of those rules equivalent to all the cars and trucks on the road in the State of Colorado. And I would note that those rules, which are really national—you know, really leading the country, those rules were put in place with the collaboration of the three largest oil and gas developers in that State at the time.

Environmental Defense Fund was there as well to help provide some technical input as well. And it was an open process, but it was truly led by the industry in saying we do need a comprehensive set of rules, we need them uniform, and we need the rest of the industry to get on board.

Ms. BONAMICI. Terrific. Thank you very much. And my—I see my time is expired. Thank you, Mr. Chairman.

Chairman BRIDENSTINE. Before going to Chairman Smith, Mr. Milito, would you comment on Aliso Canyon and how it relates specifically to the rule?

Mr. MILITO. Yes, Aliso Canyon is a very serious situation, something we never want to see happen, don't want to see happen again, but it's completely unrelated to the EPA rules we're talking about today.

We take this very seriously. And the oil and gas industry, as I mentioned, is an industry of solutions. We as API are a standard-setting organization. We create the standards for safe and environmentally responsible operations that are relied upon around the world. That's how we started.

We have two new documents related to underground storage to make sure this type of incident doesn't happen. They relate to issues such as well integrity so we've come forward with a solution.

The other thing I would add is this is not being ignored by the federal government. It's not an EPA issued. PHMSA is looking at this and addressing it and working with an interagency task force that includes API, our companies, and we're moving forward in a way where the companies are already implementing these standards. So it is wrong to conflate Aliso Canyon with emissions of methane from production facilities. They're totally separate issues.

Chairman BRIDENSTINE. Thank you. I just want to get that on the record.

Chairman Smith, you are recognized for five minutes.

Chairman SMITH. Thank you, Mr. Chairman.

First of all, let me say it's a credit to our witnesses today and to the importance of the subject matter that so many members came back after our only vote of the day to be at this hearing.

I just want to follow up before I get to my first question and say I agree with those who have expressed the sentiment today that obviously methane and carbon emissions have been going down but largely because of technological breakthroughs. The last thing we need are more government regulations which are ineffective and don't have any significant impact. It is much better to let technology provide the solution, as it always has for the history of our country. The mindset that the government knows best is not, I think, a productive mindset.

Mr. Milito, let me address my first question to you and it is this. In what ways do you feel that the EPA has misled us when it comes to the benefits of the methane regulations?

Mr. MILITO. Well, I think this gets back to the underlying science and whether or not we have a system, an economy, an industry that are already effectively addressing the methane issue. And if you look at some of the research of Environmental Defense Fund, you know, they've come forward and said, you know, if we keep supply chain emissions of methane below a 2.7 to 3.2 percent range, we get the environmental benefit. Now, the EDF studies that look at the equipment on sites, the EPA inventory, this data shows that 1.5 percent, maybe 1.8 percent, all the data shows we're well below that.

So we are in a situation right now where the data shows that we get this huge benefit from producing natural gas because it's clean burning not just from the climate change standpoint but from traditional pollutants as well, things like NOx, SOx, particulate matter. So we are winning. We're doing what we need to do——

Chairman SMITH. Exactly.

Mr. MILITO. —without the regulations.

Now, we have EPA regulations put forward. They do a regulatory impact analysis. It's a wash. If you look at EPA's own numbers, it's a wash, but then when you go back and apply the real data, the better data, the more certain data, it shows that in a year like 2025 and beyond we can be looking at cost more than $1 billion——

Chairman SMITH. Yes.

Mr. MILITO. —from a ruling.

Chairman SMITH. Mr. Milito, this is exactly the information we need to get out, and I thank you for making those points.

Dr. Weinstein, in what ways is the modeling system used by the EPA flawed or biased?

Dr. WEINSTEIN. I'm not really qualified to speak about the specifics of the EPA models. I have not studied them. My——

Chairman SMITH. Okay.

Dr. WEINSTEIN. My knowledge or my understanding is solely based on——

Chairman SMITH. Okay. That's perfectly fine.

Dr. WEINSTEIN. Okay. Yes.

Chairman SMITH. We'll come back in a minute.

Mr. Ventello, let me ask you about the impact of the EPA regulations. And I might ask Dr. Weinstein and Mr. Milito as well. What is the impact of the regulations likely to be on economic growth and job creation?

Mr. VENTELLO. Well, I—you know, I—from the standpoint of the industry itself, additional burden with low cost right now with pricing being down, as well as the fact that the industry has been pretty much self-policing. We see a lot of improvements in what they've done. And of course, as has been stated, the—you know, the release of methane is a loss of dollars, so there's a lot of effort to try to make sure that they do things with—to current standards.

But in essence, right now, in a low-cost environment it would have a substantial impact long-term just because of additional cost in nod only improving the wells but also completions and transmitting.

The key really lies in moving the gas so that you can minimize the amount of methane that is emitted from an idle situation.

Chairman SMITH. Okay. Thank you.

Dr. WEINSTEIN. But we tend to forget that we are the world's number one natural gas-producing country, and that we're also getting into the business of exporting natural gas. That has tremendous economic benefits in addition to the environmental benefits of natural gas that we've discussed. The fact that we are number one, that this is an industry that is not only empowering the U.S. economy but employs lots and lots of people and now we're getting into the export business.

So I think we need to be very careful in assessing new policies and regulations that can make it more expensive for us to produce and sell natural gas unless there's overwhelming evidence that the benefits of regulation exceed the cost.

Chairman SMITH. Okay. Thank you, Dr. Weinstein.

Mr. Milito, what about you? What about the economic impact and what about the impact on jobs?

Mr. MILITO. It could be huge. The general rule—I'm sorry. I've got to get better with my button here. It could be huge. The general rule of thumb, based upon—and what about a lot of the economists will look at is that for each Bcf of production that we have of natural gas in the United States, you get 32,000 jobs. So we've gone from 52 Bcf per day in 2007. We're at about 74 now, so, you know, just do the math and we're talking hundreds of thousands of jobs.

So you have regulations that could increase the cost on the industry dramatically. A more recent ICF study shows it could be $3.35 per Mcf, and that's based upon applying a lot of the same technologies EDF says will cost a penny. Natural gas now is $2.90. Doubling the cost of developing a resource or a product that you're selling for $2.90, it just could be devastating to consumers overall.

Chairman SMITH. All right. Thank you, Mr. Milito. Thank you, Mr. Chairman.

Ms. BONAMICI. Mr. Chairman?

Chairman BRIDENSTINE. Thank you, Mr. Chairman.

Ms. BONAMICI. Mr. Chairman, may I—before we go on, because Mr. Milito mentioned the EDF and Mr. Holstein is here, is it appropriate to have Mr. Holstein respond to the mention of his work?

Chairman BRIDENSTINE. We can—let's go to Ms. Edwards, and then maybe she can yield.

Ms. BONAMICI. Thank you.

Chairman BRIDENSTINE. Okay. Ms. Edwards, you're recognized for five minutes.

Ms. EDWARDS. I might yield. Thank you very much, Mr. Chairman, and thank you to the witnesses as well.

Mr. Holstein, in his testimony Dr. Weinstein described the methane regulations as a "solution in search of a problem," and I wonder if based on your testimony I suppose you would disagree with that. You mentioned that the knowledge base for methane is just kind of catching up. We have a huge knowledge base for CO_2 emissions. Where relatively would you put our knowledge base of methane emissions with respect to carbon—to CO_2?

Mr. HOLSTEIN. I would say catching up fast. Five years ago, nobody was paying attention to methane as a major climate pollutant. The NOAA study that was referred to earlier in its very first sentence references the fact of—that there are emissions that are of concern and throughout that study mentioned methane prominently.

Mr. Milito did mention EDF studies. I actually appreciate that mention because I think it's been remarkable how we've come together on the environmental side with the industry in conducting some of these studies, which are peer-reviewed and which are supervised by—and designed by outside independent scientists.

We can disagree about what the policy implications of those results are, but I do have to correct him on one point, which is we believe that the cumulative result of our scientific work show that we need to get methane emissions from this sector down at or below one percent, not 2.7, at or below one percent if you're going to have an improvement over what you would otherwise get if you were, for example, burning coal.

Ms. EDWARDS. So let me ask you a little bit about that because I think there's some confusion. First of all, the EPA regulations that we have discussed, EPA has imposed regulations—has put forward final regulations on new and future methane productions, right?

Mr. HOLSTEIN. Yes.

Ms. EDWARDS. And they have not done any regulating on existing—there are no proposed regulations on existing operations, is that correct?

Mr. HOLSTEIN. Also correct, yes.

Ms. EDWARDS. And so we're really speculating here as to what EPA's going to do just because they're gathering information. It's kind of their job to gather information, isn't it?

Mr. HOLSTEIN. It is.

Ms. EDWARDS. So—and—so I wonder, can you also clarify, natural gas is still a fossil fuel, right?

Mr. HOLSTEIN. It is.

Ms. EDWARDS. And it's cleaner-burning than coal and other fossil fuels, is that right?

Mr. HOLSTEIN. Yes.

Ms. EDWARDS. Which is good. But there are still environmental impacts and public health impacts for—from methane emissions?

Mr. HOLSTEIN. Yes, and it's cleaner-burning relative to coal—to answer your question of a moment ago—only if you get the emission—the fugitive emissions down at or below one percent. And that is not where we are, and that's where we need to be. Otherwise, those environmental benefits simply don't accrue.

Ms. EDWARDS. And so in your examination of some of the industry-led reports of cost-benefit analyses, do they take into consideration—in your experience, do they take into consideration the public health cost?

Mr. HOLSTEIN. They often do not, and I gave the example of Colorado where the measures that are undertaken—and remember this was a program put in place with the collaboration and cooperation of industry itself, the biggest producers in the State—puts the industry in the position of under—in Colorado of taking huge amounts of pollutants out of the air, not just the climate change.

If you didn't care about climate change at all, you would still welcome the dramatic reductions in smog-forming ground-level ozone and in the volatile organic compounds that include toxic air pollutants. And there, we're talking about premature deaths, asthma, hospitalization. And I refer you to the American Lung Association's letter on this point of December, which we'd be happy to submit for the record.

[The information appears in Appendix II]

Ms. EDWARDS. Thank you. And so my time is running out here. And so I want to give Mr. Milito an opportunity to respond. In your testimony, you say there are significant costs—you're referring to the regulations—without commensurate benefits. Does your analysis take into consideration public health costs, as well as the economic costs?

Mr. MILITO. We are looking at this from a climate standpoint. Methane is not a toxic pollutant. This is a climate question that we're talking about, and we're looking at whether or not we are achieving methane emission reductions without the costs imposed by the regulations. So we are——

Ms. EDWARDS. It is a fossil fuel though, right? It is a fossil fuel?

Mr. MILITO. It is a fossil fuel.

Ms. EDWARDS. And so—and it does still have some of the same public health costs as other fossil fuels, maybe just not to the same extent, isn't that right?

Mr. MILITO. Well, it's providing an environmental benefit to the public when you use it rather than other natural gas—other fossil fuel-powered power plants.

Ms. EDWARDS. Thank you, Mr. Milito.

Chairman BRIDENSTINE. The gentlewoman yields back.

I just want to make it clear on the record, back in May EPA Administrator McCarthy stated that she will expedite issuing regulations for reducing methane emissions from existing sources, so that is not speculation. That comes from the EPA Administrator Gina McCarthy.

I now recognize Mr. Palmer for five minutes.

Mr. PALMER. Thank you, Mr. Chairman. I'd just like to point out that there's still serious debate over whether or not the climate is warming. I think there's research out that says we haven't had a significant increase in temperature in 18 years so—that's prob-

ably—Mr. Chairman, probably going to make me subject to some kind of government retribution or a trial or something. I don't know. That is going on with some of these AG trials.

Mr. Weinstein, according to the Environmental Protection Agency's own estimates, methane emissions in the United States have decreased by six percent between 1990 and 2014. During that time period, has natural gas production in the United States increased or decreased?

Dr. WEINSTEIN. It's increased about 70 percent.

Mr. PALMER. If we do nothing at all, will the methane emissions from oil and natural gas sector continue to decrease?

Dr. WEINSTEIN. Yes, I believe so. As we've heard from Mr. Milito, the industry is embracing the best available technology to capture methane, and that is one of the reasons that we see this long-term decline.

Mr. PALMER. And one of the reasons that we have such abundant supplies of natural gas now is because technology, is that correct?

Dr. WEINSTEIN. That's correct.

Mr. PALMER. And it continues to improve almost on a daily basis, is that correct?

Dr. WEINSTEIN. Yes. It's really incredible if you consider that the rate count is down 70 percent over the last two years and gas production is only down about seven percent. That indicates that we're getting much more efficient in our ability to produce——

Mr. PALMER. Methane capture at the wellhead technology—that technology is increasing at a rapid rate. Is that also true?

Dr. WEINSTEIN. Yes, it is. And most States do have standards for, you know, capturing methane.

Mr. PALMER. And the methane that's emitted from wellheads is a relatively small amount compared to other methane sources, is that correct?

Dr. WEINSTEIN. In the overall scheme of things, yes.

Mr. PALMER. Mr. Milito, EPA issued five technical white papers covering compressors, emissions from well completions, leaks, liquids unloading, and controllers and pumps. Did the EPA properly take into account concerns that were raised by various stakeholders during the supposed peer-review?

Mr. MILITO. Not all the concerns that we had with the rules, particularly with the targeting of methane as the pollutant in this case. We felt that we could have done it without that.

Mr. PALMER. In your experience and observations, does EPA actually take into account these concerns or does it simply find friendly reviewers who will rubberstamp its agenda?

Mr. MILITO. Well, I——

Mr. PALMER. That's a loaded question but I'd like for you to give me your opinion

Mr. MILITO. Well, you know, I would like to say that the process that we're going through with EPA is actually better in many respects than what we're seeing with the Bureau of Land Management. We have meetings with EPA. We talk about them. We talk about our technology so there's a lot of back-and-forth so I would commend them for that. And they're going through a process for understanding what the data is before they move forward with potential regulations on existing sources.

On the other side of the house, we have Bureau of Land Management putting forward regulations for existing sources on federal lands without the benefit of all that data and all that knowledge. So the preferred path, if you're going to have a path, is to go through and have an analysis of the data before you move forward and try to rush regs through.

Mr. PALMER. Well, despite all the voluntary reductions and, as Mr. Weinstein pointed out, we continue to have reductions in methane emissions despite the fact that gas production has gone up tremendously. It kind of comes across like the government is selectively focusing on your industry, ignoring the benefits.

You know, it's such a contradiction here that they're concerned about greenhouse gas emissions and they force the coal industry basically to go bankrupt, as promised by our President when he was campaigning the first time. They've destroyed thousands and thousands of jobs. They've forced power companies to convert from coal to natural gas. And even though natural gas prices have come way down, energy costs have gone up.

It just concerns me that there is not a balanced approach to this in regard to looking at the economic benefits and the benefits in terms of reduction of greenhouse gases versus the benefits—versus whatever very limited impact that methane might have. It just—it appears to me there's another agenda here.

I appreciate the time, Mr. Chairman. I yield back.

Chairman BRIDENSTINE. The gentleman yields back.

I now recognize the gentleman from Texas, Mr. Weber, for five minutes.

Mr. WEBER. Thank you, Mr. Chairman. Gosh, I don't know who to direct this to. I'll just make a comment. On Ecology.com they made the statement that fossil fuels were—I just kind of read their statement. It looks like they're not—don't have a big problem with them, but the problem with them was they weren't renewable and that one day we would run out of them.

Now, it may interest you to know that that article was written by Eric McLamb on September the 6th, 2011. So things change.

You know, it seems like there was a rush to judgment. The EPA has decided that fossil fuels are bad, and I keep hearing questions from my colleagues over on the other side here, they keep saying, well, but it's a fossil fuel, isn't it, as if somehow that's the kiss of death, I guess.

Mr. Milito, EPA issued five technical white papers covering compressors, emissions from well completions, leaks, liquids unloading, and controllers and pumps. Did the EPA properly take into account concerns that were raised by various stakeholders during that supposed peer-review?

Mr. MILITO. No, the final documents that were—I don't even know if they released five. I think that after taking comment, they didn't make any changes to the document so nothing was incorporated from the public input standpoint. They just stuck with the—really the original peer-reviewed documents.

Mr. WEBER. So it was all an exercise in futility is what it sounds like.

I own an air-conditioning company 34 years. I've dealt with EPA over refrigerant trade name DuPont Freon issues for a long time.

When I was in the Texas Legislature, we dealt with licensing regulations, Texas Department of Licensing Regulations, TDLR, on air-conditioning contractors. I wanted somebody on the board that actually had experience with air-conditioning or with—whether it was refrigerant or whether it was the actual industry, not somebody that had been through school and through class and read the books and decided under the tutelage of some professor that their job was to regulate greenhouse gases or the evil energy industry. Dr. Weinstein, you have a comment?

Dr. WEINSTEIN. Well, you make a very, very good point. I think the environmental community overall is trying to tar the oil and gas industry as being evil like the tobacco industry. As we sit here today, there was a demonstration going on in front of the White House by the Keep It in The Ground movement, and this movement is growing.

So there's so much misinformation about energy, fossil fuels. Not all fossil fuels are created equally. I mean, there are lots of reasons that we're using less coal.

Mr. WEBER. Actually, they are created equally. They just decay at different levels. Go ahead.

Dr. WEINSTEIN. Well, that's one way to look at it.

Mr. WEBER. Okay.

Dr. WEINSTEIN. But—yes, so the political environment in which regulation is being crafted today is very highly charged, and unfortunately, there doesn't seem to be a middle ground or a rule of reason. There's this growing perception that fossil fuels are bad. The environmental community used to think that, oh, natural gas, that's a great bridge to the future. Now, they say it's a bridge to nowhere.

Mr. WEBER. Well, it's a fossil fuel——

Dr. WEINSTEIN. But——

Mr. WEBER. —as if that's something bad.

Dr. WEINSTEIN. But the reality is the Department of Energy says that fossil fuels are going to remain our primary energy source for the next 40 or 50 years, and that's good news.

Mr. WEBER. And, Dr. Weinstein, we have how many years of natural gas by some estimates——

Dr. WEINSTEIN. That——

Mr. WEBER. —1 or 200 years?

Dr. WEINSTEIN. That changes by the day. I mean——

Mr. WEBER. Right.

Dr. WEINSTEIN. —there was a discovery——

Mr. WEBER. Yes.

Dr. WEINSTEIN. —just a couple of days ago in West Texas, you know the High Alpine——

Mr. WEBER. Absolutely.

Dr. WEINSTEIN. —this huge, you know, billions and billions——

Mr. WEBER. Eight billion, right.

Dr. WEINSTEIN. —of cubic feet of natural gas——

Mr. WEBER. Well, the article I cited from Ecology.com we're going to run out of natural gas—this is September the 6th, 2011, clearly before the—Mr. Milito, you also said—I missed the numbers in your earlier testimony—that one billion cf of natural gas produces how many jobs? You quoted——

Mr. MILITO. One billion, Bcf per day of natural gas equates to approximately 32,000 jobs.

Mr. WEBER. Thirty-two thousand jobs. One of the things I say when I speak to groups around the country is that the things that make America great are the things that America makes. Now, how do we do that? We have a reliable, affordable, dependable, clean source of energy for the most part. I get there's problems where the pipelines rupture and you were talking about PHMSA earlier, and of course you know the pipeline industry, Mr. Milito, has a 99 percent safety rating.

And so for this idea to be that somehow we've got to kill all this fossil fuel energy and go on either solar or wind—and that's not even discounting for nuclear that I used to have in my district when I was in the State Legislature—it just boggles my imagination that we've got an agency that we have reduced their budget to—by $420 million into pre-1989 levels and they're still pumping out regulations, as you pointed out, with a supposed comment period. They're still pumping out regulations at a record rate.

I think we need some cooler heads to prevail, and I think we need some logic to prevail. You know, the EPA is supposed to take into account the effects on what it does to the industry before they issue regulations, and we really quite frankly don't see them doing that, and I hope that Congress exercises its oversight control and gets that under control. And I appreciate you all being here to testify.

Mr. Chairman, I yield back.

Chairman BRIDENSTINE. The gentleman yields back.

I now recognize the gentleman from Texas, Mr. Babin, for five minutes.

Mr. BABIN. Thank you, Mr. Chairman.

Mr. Ventello, according to the Centers for Disease Control and Prevention, excessive heat is the leading cause of preventable weather-related deaths each year, particularly among the elderly. In June of 2013, President Obama in a "New York Daily News" editorial stated that "The bottom line is natural gas is creating jobs. It's lowering many families' heat and power bills." Do you find it ironic that these deaths from excessive heat could be prevented by electricity—cheap, reliable natural gas from Pennsylvania or even New York instead of lowering electricity usage that has been encouraged by Governor Cuomo?

Mr. VENTELLO. Yes, it is ironic. We—with the surge of the—of this cheap fuel, obviously the industry itself—energy generation is probably the most prolific if you will development with natural gas that reaches more people than any other single use of natural gas. We all use electricity. So to answer your point, yes.

Mr. BABIN. Okay. And then do you think citizens have been misinformed by the media and certain advocacy groups about natural gas well operations?

Mr. VENTELLO. Yes, I believe so. And let me give you a—just a simple example.

Mr. BABIN. Okay.

Mr. VENTELLO. Our Emergency Operations Director if a—for instance, if a tanker of diesel fuel spills delivering fuel to a family farm, that's one day's news. If a vehicle or some sort of an accident

happens with a gas-related vehicle, he gets a call from the media looking for that separation. That becomes news in the New York Times. I see it all the time. People send me that information. So yes, there is a strong misinformation.

I think the best thing—the most powerful thing I can do is ask people to come there and see it and make up their own minds.

Mr. BABIN. Do you think that these advocacy groups are aware of the progress that has been made in this industry on reducing methane emissions?

Mr. VENTELLO. I think that they—in many cases they may be but there's nothing you can say that will convince them to change their minds.

Mr. BABIN. I got you. And then how would poorly thought-out, hasty regulations stop economic revitalization and development that has been occurring in northeast Pennsylvania?

Mr. VENTELLO. Simply by placing unnecessarily—unnecessary burden by additional costs on the industry, which is already moving in the right direction.

Mr. BABIN. And then would it be fair to say that the production of natural gas has benefited the entire community such as the building of new hospitals, thus improving the health quality of all residents of northeast Pennsylvania?

Mr. VENTELLO. Yes, and beyond that. Everything that you and I use, the industry uses, and there's been an extreme—in many cases where the industry has made—been made to pay impact fees, those dollars have gone back into a lot of different benefits to the general community——

Mr. BABIN. Right.

Mr. VENTELLO. —both in health care, as well as housing and the like.

Mr. BABIN. Thank you very much, Mr. Ventello, and I appreciate all the witnesses today. I yield back the balance of my time.

Chairman BRIDENSTINE. The gentleman yields back. We're coming to the end of this hearing.

Mr. Milito, did you want to—I'll give you about a minute if——

Mr. MILITO. Yes, I have a correction——

Chairman BRIDENSTINE. And then just——

Mr. MILITO. —for Congresswoman Edwards. I'm actually looking at our regulatory impact analysis, and we did in fact look at the benefits of reducing methane emissions. And in one case there are actually—our estimates show that they were greater than what the government showed, but at the same time we saw the cost appreciably higher, which gives you a much lower net benefit overall.

And I would look at the Intergovernmental Panel on Climate Change which states that greenhouse gas emissions from energy supply can be reduced significantly by shifting to modern, highly efficient natural gas combined cycle power plants.

So we have the data which shows that we're in a good position and it just begs the question as to whether or not these regs are required.

And the last thing I would ask is to get some confirmation from the EDF because it's news to me that it's one percent. All the studies that we've seen show you have to be lower than 2.7 to 3.2 percent when it comes to coal. I understand that natural gas in trans-

portation might have a different threshold, but I think we have to get that information correct, so I think it would be good for all of us to learn that because that's good information to know.

Chairman BRIDENSTINE. Mr. Holstein, would you like to take a minute to respond to that?

Mr. HOLSTEIN. Yes, just to commit to Mr. Milito that we'd be happy to provide it. And we do note two things that have been referenced. One is that we absolutely do accept and acknowledge the positive role that natural gas has played in helping to improve, for example, our air quality and reduce greenhouse gas emissions, again, underscoring this point that getting a handle on methane how—is critical to ensuring that the benefits of gas truly do accrue to the society, to the world at large.

Whether you're concerned about health benefits or climate or both, and the voluntary reductions, are—talking about those are a mixed bag. The green completions that Mr. Milito referred to and some of the other reductions—reduction-driving measures that have been taken by industry have been taken as a direct result of earlier EPA regulations.

That's not to say that there aren't good environmental values in the industry. I mentioned Colorado where they certainly came to the fore. And ONE Future is a good example, but ONE Future's membership is now part of EPA's challenge—Methane Challenge voluntary program, but there are only 10 companies participating and we need a lot more leadership and participation from the industry. And I hope Mr. Milito is right that the industry is headed in that direction.

But we also need, because of some of the complexities of measuring, of detecting and responding to methane emissions, we do need to have comprehensive methane detection, leak detection and repair programs in order to really ensure that the industry has the information they need so when this invisible gas is leaking, people know where it is.

I should note in reference to that list of things like controllers and valves and that sort of thing, many of these components that we've talked about were designed to leak back when nobody thought—gave a thought about methane. They were actually designed to be driven by the pressures in the gas line. So those are examples of things that are easily fixable but we need to get on top of it.

Chairman BRIDENSTINE. Ms. Bonamici, you had something?

Ms. EDWARDS. Mr. Chairman—yes. Mr. Chairman, I just wanted to note that I was asking about public health benefits, but I'm going to submit a question for the record along with a statement from nurses and physicians about the public health——

Chairman BRIDENSTINE. Absolutely.

Ms. EDWARDS. —costs. So thank you very much for that.

Chairman BRIDENSTINE. You bet.

[The information appears in Appendix II]

Chairman BRIDENSTINE. Do you have something final?

Ms. BONAMICI. No. That——

Chairman BRIDENSTINE. Okay.

Ms. BONAMICI. —was Ms. Edwards.

Chairman BRIDENSTINE. Okay. I'd like to thank the witnesses for their valuable testimony and Members for their questions. The record will remain open for two weeks for additional comments and written questions from Members.

This hearing is adjourned. Thank you all.

[Whereupon, at 11:43 a.m., the Subcommittee was adjourned.]

Appendix I

Answers to Post-Hearing Questions

ANSWERS TO POST-HEARING QUESTIONS

Responses by Mr. Erik Milito

energy API

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December 5, 2016

Honorable Lamar Smith
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Honorable Jim Bridenstine
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SUBJECT: API Answers to Question for the Record, House Committee on Science, Space and Technology, Subcommittee on Environment, Hearing entitled "A Solution in Search of a Problem: EPA's Methane Regulations"

Chairman Smith and Chairman Bridenstine,

Thank you again for the opportunity to testify before the House Committee on Science, Space and Technology, Subcommittee on Environment, in the hearing entitled "A Solution in Search of a Problem: EPA's Methane Regulations." The following answers are provided to the two questions for the record that I received following the hearing. Please do not hesitate to reach out to me should you have any follow-up questions. Our industry remains committed to safe and environmentally responsible offshore operations and we stand ready to work with the Department of the Interior to ensure that any changes to regulatory regime truly advance safety.

Question 1: During the hearing, Mr. Holstein claimed "cutting methane emissions is generally very expensive but the cost of methane leak detection surveys is relatively low as well. Today, methane inspections can cost as little as $250." Is Mr. Holstein exaggerating or giving a biased viewpoint about this matter?

Response: Based upon the practical experience of the industry in deploying leak detection technologies, Mr. Holstein's testimony exaggerates the actual costs. API surveyed the industry and provided detailed comments to EPA related to the imposition of leak detection requirements. API's analysis demonstrates that a leak detection program is estimated to cost $15,607 per well

site for the first year, and $1,590 per well site for each year thereafter. Please note that there are hundreds of thousands of well sites in the United States.

The following tables compare cost information for semi-annual OGI LDAR surveys and a 10,000 ppm leak definition based on data from companies conducting voluntary LDAR versus EPA's cost assumptions. Yellow highlighted cells indicate where costs are different and costs that EPA did not include in their analysis. Overall, API cost data indicate slightly lower well site costs ($1,590 based on API estimates compared to $2,096 from EPA's estimate as shown in the tables below). However API's estimate includes recurring annual costs that were neglected in EPA's estimate and significantly higher company level costs. The resulting total annual cost estimate from API member companies is almost three times higher than EPA's estimate.

Comparison of Monitoring Costs – One Time Company Level Costs

Item	API Annual Total Cost ($)	EPA Annual Cost ($)	Comment
One-Time Company Level Costs			
Read rule and instructions	$231.20	$231.20	Cost based on hours from PES Memorandum
Development of Equipment Leaks Monitoring Plan - Corporate Plan	$7,200.00	$3,468.00	API members estimate $7,200 to develop the initial corporate monitoring plan. EPA estimated cost based on average number of people and hours from PES Memorandum
Initial Activities Planning	$1,849.60	$1,849.60	EPA cost based on hours from PES Memorandum
Notification of Initial Compliance Status	$1,271.60	$1,271.60	Assumes that 1 hour is spent to prepare the notification for each well site for 22 well sites
FLIR Monitoring - Cost of OGI Equipment	$95,000	Excluded from EPA's analysis	API survey responses ranged from $90K-100K. API estimate conservatively assumes just 1 device is purchased.
FLIR Monitoring - Cost of Data Management System	$225,000.00		API survey responses ranged from $200K-250K
FLIR certification Training	$2,000.00		API estimate conservatively assumes only one person is trained
M21 Monitoring and Data Collection System	$10,800	$10,800	EPA estimate includes cost of M21 monitoring device ($10,800) but excludes the cost of the data collection system ($14,500) that was assumed for M21
First Year Total Hours and Cost per Company	*$343,352*	*$17,620*	Sum of total company costs above
First Year Total Hours and Cost per Well Site	*$15,607*	*$801*	Assumes company owns 22 well sites

Comparison of Monitoring Costs – Annual Costs

Item	API Annual Total Cost ($/yr)	EPA Annual Cost ($/yr)	Comment
RECURRING ANNUAL COSTS			
Annual Training	$2,000.00	Not included	API estimates for annual training ranged from $1,000 to $5,000. Conservatively assumed $2,000/yr
Data Analyst	$24,000.00	Not included	API estimate based on 10% resources of existing data analyst duties
Annual FLIR Device Calibration	$4,000.00	Not included	API estimates ranged from $3,000 - $5,000/camera. Conservatively assumed just one device is needed.
Annual transportation costs	$20,000.00	Not included	Per basin cost. API estimate assumes one basin requires 15,000 miles travel annually. Includes fuel and maintenance. Does not include the cost of purchasing a vehicle.
Recurring Annual Costs per Company	*$50,000.00*	*Not Included*	Sum of recurring annual costs above
Recurring Annual Costs per Well Site	*$2,272.73*	*Not Included*	Assumes company owns 22 well sites
Well Site Level Costs			
Subsequent Activities Planning	$63.05	$63.05	Based on hours from PES Memorandum. Total cost of planning divided by total number of well sites per company
Development of Site-specific Monitoring Plan	$120.00	Not Included	API estimate assumes 2 hours per site to develop the proposed site-specific monitoring plans
FLIR Survey cost	$462.40	$1,200.00	EPA cost from CL Report (outside contractor, well pad, $600 per survey). API estimate assumes 1 person and 4 hours to survey a well site using FLIR. Includes travel time.
Repair Cost	$597.48	$597.48	Assumes 1.18% or 4 total leaks found per survey, 3 fixed online (3 * 0.17 hours *$66.24/hr) and 1 fixed offline (1 * 4.0 hours * $66.24/hr)
M21 Resurvey Costs	$115.60	$4.00	EPA's resurvey costs assume cost of $2.00 per component for offline component repair. API's resurvey cost assumes 2 hours are required to travel to/from the site and resurvey the fixed component.
Annual Report	$231.20	$231.20	Assumes that 4 hours are spent to prepare the

Item	API Annual Total Cost ($/yr)	EPA Annual Cost ($/yr)	Comment
			annual report for each well site and includes storing/filing of records
Cost per Well Site (Well site level costs only)	*$1,590*	*$2,096*	Sum of well site level annual costs
Annual Cost per well site with Amortized Capital Cost	***$6,476***	***$2,230***	**Includes first year costs per company site from table above, cost amortized over 8 years at 7% interest**

In addition, a May 2016 study by ICF International, entitled "Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems" concluded that the marginal abatement cost (MAC) of various methane emission abatement technologies and work practices for the natural gas industry is estimated at a total annualized cost of $296 million or $3.35/Mcf of methane reduced for all segments except the distribution segment. To put that in context, today natural gas is trading at $3.60/Mcf and has frequently traded below $3.00/Mcf over the past few years. To put a finer point on it, the cost of the methane abatement technologies being promoted is nearly 100% of the cost of the product being captured.

We would add that the industry is at the forefront of developing the technologies for reducing methane emissions, and this includes developing technologies to detect leaks. This is apparent in the industry's demonstrated success in reducing methane emissions from oil and natural gas well sites over the past several years, and as reflected in the emissions data. The industry will continue to innovate and advance technologies, including leak detection technologies. However, one-size-fits-all approaches are not suitable and can actually stifle the development of new and better technologies.

Question 2: The American Lung Association (ALA) issued a letter this past December in favor of stronger methane standards. It appears that this letter may have selective referencing of facts and claims by the ALA. Could you please set the record straight on health claims and benefits as it relates to EPA's methane rules? Please explain, in detail, if there are any "facts" taken out of context or misattributed.

Response: As I stated in my testimony, natural gas is an extremely clean burning fuel. According to the Energy Information Administration, use of natural gas has surpassed coal in generating electricity, and carbon dioxide (CO2) emissions from the power sector are at 20 year lows, primarily due to the increased use of natural gas for electricity generation. Increased use of natural gas has also led to lower emissions of criteria pollutants such as sulfur dioxide (SO2), nitrogen dioxide (NO2) and fine particulate matter (PM). Researchers at Carnegie Mellon University recently released a study entitled "The climate and health effects of a USA switch from coal to gas electricity generation." The study finds significant health and climate benefits as a result of the increased use of natural gas for electricity generation. In fact, the study

concludes that there could be as much as $20 to $50 billion in healthcare cost savings related to increased natural gas usage:

"The human health benefits of such a switch are substantial: SO2 emissions are reduced from the baseline (MATS (Mercury and Air Toxics Standard) retrofits by 2016) by more than 90%, and NOX emissions by more than 60%, reducing total national annual health damages by $20 to $50 billion annually."

Allegations continue to be made that methane leakage in the natural gas supply chain could adversely impact the positive greenhouse gas reduction benefits from increased use of natural gas in power generation. However, the data do not support those claims. Based upon examination of the data, the methane leakage or loss rate is very low, and well below the level that would implicate the positive climate benefits from increased use. Furthermore, methane leakage is wholly unrelated to the tremendous health benefits that are achieved from reductions in sulfur dioxide, nitrogen oxides, and particulate matter that occur through the increased use of natural gas in electricity generation.

On top of that, methane is generally understood to be nontoxic (although it is flammable and can displace oxygen). Methane is the primary component of natural gas which is used in many households for stovetop cooking, fueling our furnaces, and heating our hot water tanks.

To the extent EPA's rules are designed to reduce emissions of volatile organic compounds (VOCs), API and its members are committed to cost-effective approaches for reducing those emissions. API worked with EPA throughout the development of the 2012 New Source Performance Standards (NSPS) Subpart OOOO rule addressing VOC emissions and its expansion to additional sources in the 2016 rulemaking that added methane as a regulated pollutant, in the 2016 rulemaking. API maintains that the inclusion of methane as a regulated pollutant in the 2016 rule is not warranted until the EPA adequately demonstrates that the source category is a *significant* contributor as required under the Clean Air Act.

Thank you again for the opportunity to testify and to provide responses to these questions.

Best regards,

Responses by Mr. Elgie Holstein

EDF
ENVIRONMENTAL DEFENSE FUND
Finding the ways that work

Questions for the Record

From Elgie Holstein
House Science Committee
Subcommittee on the Environment
Hearing on 9/15

Questions from Chairman Lamar Smith

1. **When was the last time you, personally, visited an oil and gas extraction site? (If applicable, please state the location(s), date(s), and length(s) of visit.)**

During my career, I have visited oil and gas production sites, both onshore and offshore, a number of times. I last visited oil and gas production facilities on May 31, 2013, in the San Antonio area.

2. **What technical expertise do you, personally, have about extraction methods related to the oil and gas industry? Do you, personally, have any formal education related to these methods?**

ANSWER: I have been working in energy policy for more than three decades, including at the Department of Energy, the Department of Commerce, and the White House Office of Management and Budget. While I consider myself reasonably familiar with oil and gas exploration and production methods and technology, I do not have formal technical training or education in extraction methods.

I wish to emphasize, however, that Environmental Defense Fund, in conducting our scientific work regarding methane, has collaborated with a broad cross-section of experts who do have such training and expertise.

In 2012 EDF launched a major scientific research collaboration involving 16 studies designed to quantify methane emissions from the natural gas supply chain. Over two dozen peer-reviewed papers have been written as a result of that work, and they have significantly increased our understanding of the problem of emissions from the oil and natural gas supply chain.

The research was mostly led by academic researchers (EDF scientists took the lead on three of the studies) with significant collaboration by oil and gas industry companies. In all, there were over 100 academic and industry partners. The research examines all areas that make up the oil and gas supply chain: production, including well pads; gathering lines and processing facilities; long-distance pipelines; storage, local distribution and natural gas vehicles. Conducting these studies included visits to hundreds of oil and gas facility sites and remote surveys of thousands more, and it involved a diversity of techniques including top-down and bottom-up surveys, monitoring using infrared cameras and other measurements using cutting edge technology. While all participants may not agree with our policy recommendations, the scientific information developed in the course of the studies was based on the work of many highly qualified and trained individuals, companies, and academic institutions.

3. **During the hearing, you stated the following during an exchange with Rep. Edwards:**

   "... we believe that the cumulative result of our scientific work shows that we need to get methane emissions from this sector down at or below one percent, not 2.7, at or below one percent if you're going to have an improvement over what you would otherwise get if you were, for example, burning coal."

   a. **How did you determine this specific number of one percent that you referenced during your response? Where can we find your specific claim in the peer-reviewed scientific literature?**

   b. **Has this one percent number claim been peer-reviewed by independent sources? Has this number, or the underlying analysis that calculated this number, been independently verified in other peer-reviewed publications? (If the answer to either of this (sic) questions is NO, we request that you provide any raw scientific data-sets and technical analysis related to this one percent claim. Please include these materials with your response.)**

ANSWER: At the hearing, Eric Milito of the American Petroleum Institute, said that EDF's research shows that,

> "... if we keep supply chain emissions of methane below a 2.7-3.2% range, we get the environmental benefit [of burning gas instead of coal.] Now, the EDF studies that look at the equipment on sites, the EPA inventory, this data shows that 1.5% maybe 1.8% -- all the data shows that we're well below that. So we are in a situation right now where the data shows that we get this huge benefit from producing natural gas because it's clean burning, not just from a climate change standpoint, but traditional pollutants as well. Things like NOx, SOx, particulate matter. So we are winning. We're doing what we need to do without the regulations."

I disputed that interpretation, and argued throughout the hearing that more needs to be done to reduce emissions, and that comprehensive rules are needed.

All other things being equal, reducing methane emissions from gas might make that fuel better than another fossil fuel from a climate perspective, but that is not the same thing as saying the industry is "winning" environmentally and causing no harm from its methane emissions. The natural gas industry needs to do a better job reducing methane leaks, and federal regulations are needed to make sure all industry participants are playing by the same rules.

From a climate standpoint, the important question isn't the *relative* emissions of gas vs. coal – it's the total *amount* of those emissions released to the atmosphere that matters.

The oil & gas industry in the U.S. alone generates nearly 10 million metric tons of methane a year according to the most recent EPA data. That's 34 percent higher than the agency's previous estimates. Because methane is such a powerful greenhouse gas, those emissions have the same 20-year climate impact as the CO2 from over 200 coal-fired power plants, or 170 million cars.

I did mistakenly characterize EDF's studies as showing a required threshold of 1% in order to realize an advantage for gas over coal – in fact, the 1% threshold established in previous research applies to natural gas-powered transportation in comparison to diesel, (a point conceded by Mr. Milito).

The discussion of an emissions "threshold" below which there is an environmental benefit from gas relative to other fossil fuels misses essential points of my testimony: That methane is responsible for 25% of the global warming we are experiencing now, based on EDF analysis of IPCC data; that more than half the warming we will experience over the next couple of decades is due to current emissions of short-lived climate pollutants such as methane; and that significantly lowering methane emissions from the oil and gas sector – which is the largest source of U.S. methane emissions – can be done cost-effectively using widely available technology.

That being said, EPA estimates that the overall methane leakage rate from the oil and gas supply chain is about 1.5 percent. EDF believes that the actual leak rate is higher, based on our preliminary integration of the large body of research published in peer-reviewed scientific literature over the past three years. EDF's preliminary estimate for the actual aggregate number in the U.S. is probably 2 - 2.5 %. That is very close to the threshold Mr. Milito prefers to emphasize.

Part of the reason for that higher estimate is that the studies have shown that significant volumes of methane are released from the oil and gas sector as a result of random, high-volume leaks that are not fully reflected in the EPA inventory of emissions.

In addition, as I discussed in my testimony, the health effects of natural gas leaks are also significant, as detailed in a December 2015 letter from the American Lung Association to EPA Administrator McCarthy, to which Rep. Edwards referred during the hearing.

In our view, the EPA rules provide a benefit not just in terms of reduced health-related climate impacts (which include the many health-related problems created over the long term by higher temperatures), but also in terms of *immediate* impacts on public health. For example, the state of Colorado's oil and gas rules will cut 100,000 tons of methane and 90,000 tons of VOCs, the annual equivalent from all the cars and trucks in Colorado today.

These points underscore the need to reduce methane emissions *as much as possible as quickly as possible* using every reasonable means. The rapid expansion of natural gas use, combined with the potency of methane emissions, underscores the urgency of that principle.

It is true that natural gas has helped accelerate the overdue retirement of obsolete coal-fired power plants in the U.S. EDF has long acknowledged that this is a positive trend for the environment. But while gas might be somewhat better from a global warming standpoint, it is not doing as much good for the environment as Mr. Milito claimed, and certainly not enough to solve our climate problems. And that is why EPA rules are necessary. .

Questions from Ranking Member Bonamici

1) **I understand that the Environmental Defense Fund (EDF) is engaged in a substantial amount of work surrounding methane emissions, and I note in your written testimony you describe that much of this work is designed to better identify the extent and sources of methane emissions.**

   - **Please explain why EDF has found it important to devote such time and resources to address methane.**

   - **Can you describe the difference between the long-term climate impacts of carbon dioxide, and the short-term climate impacts of methane?**

   - **Why is greater leak detection important and how do the Environmental Protection Agency's (EPA) rules facilitate such improvements?**

Why EDF embarked on this research project

Methane is the primary component of natural gas. When it escapes unburned into the atmosphere from oil and gas operations during the production, delivery process, it can greatly contribute to climate change. In fact, it is 84 times more potent than carbon dioxide in the first 20 years after it is released.

Until recently, however, little was known about exactly where and how much methane was emitted during oil and gas activities. Meanwhile, oil and gas production has been rapidly expanding across the country in recent years, with few regulations to keep air pollutants like methane in check.

That's why in 2012, Environmental Defense Fund spearheaded a series of 16 independent, rigorously executed projects, to better understand from where and how much methane is lost across today's U.S. oil and natural gas supply chain, including from production, gathering and processing facilities, gas transmission and storage, and local utility distribution.

EPA's recent inventory also confirms this problem is too big to ignore. The onshore oil and gas industry released 9.8 million metric tons of methane in 2014, a number 34% higher than past estimates suggested. This pollution had the same negative impact on the climate as the annual carbon emissions of 170 million cars, or roughly half the cars in the United States, and over 220 coal burning power plants. It is also a significant source of energy waste, and could have met the heating and cooking needs of over 7 million homes.

We must address methane AND carbon dioxide

Methane is a powerful greenhouse gas pollutant, 84 times as potent as carbon dioxide over the first 20 years after release. While methane does not stay as long in the atmosphere as carbon dioxide, it packs a powerful punch over the time it's in the air. In fact, our analysis based on IPCC data found that estimates that it is responsible for 25 percent of the manmade global warming we're experiencing today.

An effective climate change mitigation strategy requires aggressive action to reduce carbon dioxide *and* methane. The increase of carbon dioxide in the atmosphere determines the total amount of warming our planet will experience, therefore, action to reduce it lowers the chance of long-term catastrophic climate change. On the other hand, mitigating methane emissions

reduces the rate of warming we will experience in the short term, decreasing the near term probability of intense heat waves slowing rapid sea level rise.

Action on both pollutants is necessary in the battle against climate change, and EDF has staff working extensively to reduce both pollutants including through advocating policies to cut methane and accelerate the adoption of lower carbon policies such as renewable energy and energy efficiency.

Importance of Leak Detection and Repair

Some methane emissions are intentional, due to venting, incomplete flaring, and other activities. But half of all the industry's methane emissions come from unintentional leaks, which can happen anywhere on the oil and gas supply chain from remote wellheads to the utility gas lines under our neighborhood streets. Methane leaks, which are most often colorless and odorless, come in all sizes, are as unpredictable as they are widespread.

That means that to find leaks, companies have to be looking regularly, and fixing the ones they find. Leak detection and repair – referred to in the industry as "LDAR" – is a straightforward way to reduce oil and gas methane emissions from all facilities.

Leading production regions, including Colorado, parts of Wyoming, California, Ohio, and others have proposed or currently have clean air protections in place that require regular leak detection and repair from sources in the oil and gas industry.

EPA's recently finalized New Source Performance Standards also require oil and gas operators to check well site facilities for methane leaks on a semi-annual basis and compressor stations on a quarterly basis

However these EPA rules do not address the 9.8 million metric tons of methane pollution currently being released by the oil and gas industry every year. In order to address this problem we need EPA to address methane pollution from existing sources in the oil and gas industry, including the same regular, rigorous leak detection and repaid requirements. Fortunately these surveys are inexpensive, and costs are declining further thanks in part to America's innovative methane mitigation industry, whose companies have over 500 locations across 46 states.

2) **In his written testimony, Dr. Bernard Weinstein referenced a NOAA study, stating: "But a recent study by the National Oceanic and Atmospheric Administration (NOAA) finds that the 'U.S. energy industry contributes little to the overall burden of global fossil fuel emissions.' Rather, according to NOAA, wetlands and agriculture are the main culprits." I have sent a letter to NOAA's Chief Scientist, Dr. Richard Spinrad, asking for clarification of the nature and findings of the study. I have attached a copy of my letter for your review.**

   - **How would you respond to the statement that, "the U.S. energy industry contributes little to the overall burden of global fossil fuel emissions?"**

ANSWER: Approximately 25% of the manmade global warming we're experiencing today is caused by methane emissions, according to EDF's analysis of data from the Intergovernmental Panel on Climate Change.

Data that the United States submits to the Unite Nations Framework Convention on Climate Change shows that the oil and gas industry is the leading source of methane emissions here in the US. Similar data from other countries was used in and analysis by the Rhodium Group, which found that roughly 3.5 trillion cubic feet of methane escaped from the global oil and gas supply chain in 2012, an amount about equal to about 3% of global natural gas production. These emissions have the same near-term climate impact as about 40% of annual global coal combustion.

The good news is this is a huge opportunity: a 45 percent reduction in oil and gas methane emissions worldwide would have the same impact on the climate over 20 years as closing one-third of the world's coal plants. That's why the International Energy Agency named reducing methane emissions from the oil and gas sector as one of five key ways to deliver a peak in global energy-related emissions by 2020, without reducing economic growth.

This is a problem we need to address, but one we can't solve alone. Fortunately earlier in 2016, Canada and Mexico also joined the United States in committing to reducing methane from the oil and gas sector by 45% by 2025. These three countries are among the world's top oil and gas producers and together are responsible for almost 20% of worldwide methane emissions from oil and gas.

- **Are you familiar with the study referenced by Dr. Weinstein? If so, would you please characterize the findings of the study as it may relate to EPA's methane rule?**

ANSWER: The NOAA study referenced at the hearing makes clear that methane is a major climate pollutant of concern. The study is one of a group of recent studies looking at global methane emission trends. Although these studies reach different conclusions about the exact attribution of methane emissions, they all indicate that methane emissions are high and reinforce the opportunities and climate benefits from cutting methane pollution.

While it is valuable to understand trends in methane emissions, the more important information to know is current emission levels. More recent data from NOAA and other sources has found that methane emissions today are very high, and that oil and gas is a big part of that. Specifically, a study released earlier this month found we're underestimating how much methane comes from the production, delivery and use of oil and gas and the production of coal globally by 20–60 percent.

These findings mirror results of many of the studies of methane emissions from the natural gas supply chain coordinated by EDF, which also found that overall levels of methane coming from U.S. oil and gas production and delivery infrastructure were higher than previously thought. In one of those analyses – which included the use of diverse types of measurements – emissions were nearly double what the Environmental Protection Agency had previously estimated. This and other recent studies provided some the critical information leading to the agency's recent 34% upward revision of oil and gas methane emissions, finding the U.S. onshore oil and gas industry releases almost 10 million metric tons of methane every year.

Evidence clearly shows that voluntary measures alone cannot be relied on to cut this potent pollution. We need strong safeguards to protect the climate and our communities from the oil and gas industry's methane and other air pollution.

Fortunately EPA has taken an important first step in doing that by finalizing EPA's New Source Performance Standards. However these rules do not address the hundreds of thousands of oil and gas facilities in operation today, allowing them to continue to leak methane and other air pollution. That's why we need EPA to establish common-sense regulations addressing existing oil and gas sources.

Appendix II

Additional Material for the Record

STATEMENT SUBMITTED BY COMMITTEE RANKING MEMBER
EDDIE BERNICE JOHSNON

OPENING STATEMENT
Ranking Member Eddie Bernice Johnson (D-TX)

House Committee on Science, Space, and Technology
Subcommittee on Environment
"A Solution in Search of a Problem: EPA's Methane Regulations"
September 15, 2016

Thank you Mr. Chairman, and thank you to the witnesses for being here today.

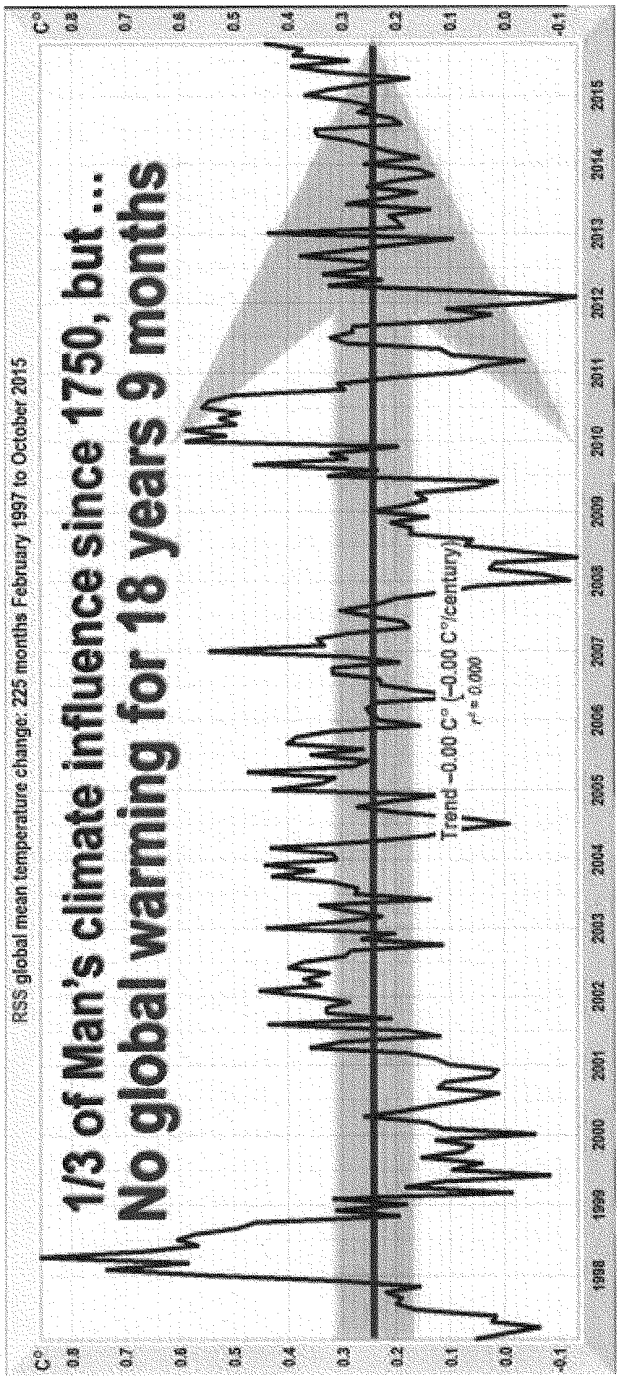
I am disappointed, but not surprised, that the Majority has decided to again hold a hearing attacking EPA regulations. Contrary to the hearing title, EPA's new methane regulations are a solution to a very real problem, and a positive step forward to addressing greenhouse gas emissions.

Despite the familiar criticisms of EPA actions, the American people have been clear in their support for these regulations. In June, the American Lung Association released polling data which showed that 60 percent of American favor EPA's methane regulations. The President of the American Lung Association, Harlod Wimmer, said, "The new methane standards mark an important step in the fight against climate change and will also cut toxic air pollutants that threaten the health of Americans."

As I have said before, the Environmental Protection Agency works hard to protect the public health and the environment, and it is clear that these regulations are simply a result of their efforts to fulfill that mission. We must work with EPA, not against them, if we want to achieve strong environmental regulations that improve the health of both the planet and the economy.

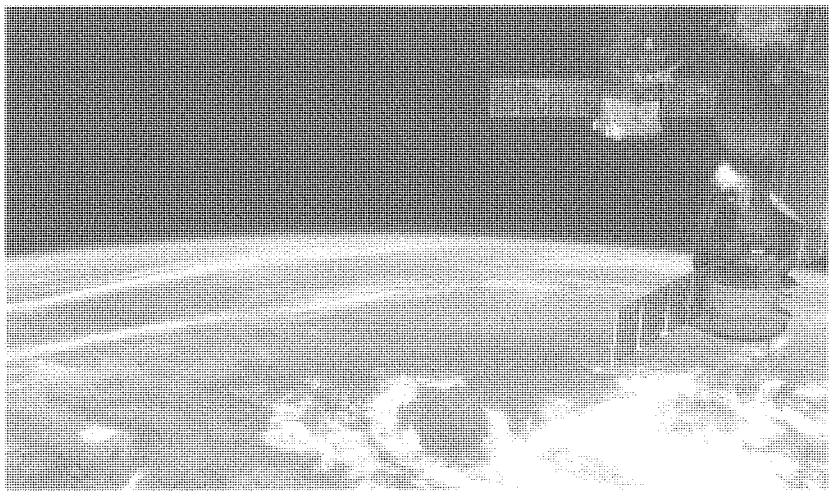
Thank you, I yield back.

DOCUMENTS SUBMITTED BY REPRESENTATIVE GARY PALMER



A new Little Ice Age?

Instead of dangerous warming, Earth could be entering a chilly era



This image made from video provided by NASA shows part of the International Space Station with the Earth in the background on Wednesday, Feb. 25, 2015. (AP Photo/NASA) more >

By Paul Driessen - - *Sunday, May 17, 2015*

ANALYSIS/OPINION:

President Obama continues to prophesy "dangerous" global warming, due to fossil fuels. Computer modelers conjure up crisis scenarios based on their assumption that carbon dioxide drives climate change.

What if they are wrong? What if the sun refuses to cooperate?

"The sun is almost completely blank," meteorologist Paul Dorian notes. Virtually no sunspots darken its face. "The main driver of all weather and climate has gone quiet again during what is likely to be the weakest sunspot cycle in more than a century."

Going back to 1755, only a few solar cycles have had a lower number of sunspots during their maximum phase, he adds. This continued downward trend began two decades ago, just before Earth stopped warming. If sunspots continue declining for a couple more cycles, Earth could enter another "grand minimum," an extended period of low solar activity.

Reading University space physicist Mike Lockwood agrees. Solar activity is falling perhaps "faster than at any time in the last 9,300 years," he observes.

That would mean less incoming solar radiation, which could have a marked cooling effect — as happened during previous decadeslong episodes of low solar activity. The "Maunder Minimum" lasted 70 years (1645-1715), the "Dalton Minimum" 40 years (1790-1830). They brought even colder temperatures to the "Little Ice Age."

Habibullo Abdussamatov, director of Russia's space research laboratory and its global warming research team, is convinced another little ice age is on its way. That would be Little Ice Age No. 19.

A couple degrees warmer would be good for humanity and planet, especially with more plant-fertilizing carbon dioxide in the air. Crops, forests and grasslands would grow faster and better. Longer growing seasons over larger areas of land would support more habitats, wildlife, agriculture and people — particularly if everyone has access to ample, reliable, affordable motor fuels, electricity and modern farming technologies.

Most people, including the elderly, can easily handle such warmth, especially with air conditioning.

But a couple degrees colder would bring serious adverse consequences for habitats, wildlife, agriculture and humanity. This does not mean another Pleistocene ice age — with glaciers obliterating forests and cities under mile-thick walls of ice across North America, Europe and Asia. It may not even mean a full-blown little ice age.

However, just a 2-degree drop in average global temperatures would shrink growing seasons, cropland and wildlife habitats. Agriculture would be curtailed across Canada, northern Europe and Russia, putting greater pressure on remaining land to feed hungry families without turning more habitats into cropland. Land now devoted to corn for ethanol would have to be returned to food crops.

Our ability to feed Earth's growing population would be seriously impaired, especially if radical environmentalists continue opposing chemical fertilizers, insecticides, biotechnology and mechanized farming. Those technologies would ensure far more food per acre under colder conditions, even if anti-hydrocarbon policies mean crops are starved for carbon dioxide.

Colder climates can also bring more unpredictable storms and cold snaps during shortened growing seasons. That happened frequently during the last Little Ice Age (1350-1850), spreading crop failures, hunger, malnutrition, starvation and disease across much of Europe.

Worst of all, cold kills. Modern homes and buildings with affordable heat make it easy to survive even brutal winters in comfort. However, carbon taxes, restrictions on coal and natural gas, renewable energy mandates and other ill-conceived programs have sent electricity and home heating prices soaring.

When energy is rationed, expensive and unpredictable, businesses lay off people or close their doors. Forced into welfare, people suffer poor health and well-being. The elderly are especially susceptible.

In Britain, many pensioners now ride buses or sit in libraries all day to stay warm; others burn used books in stoves. (They're cheaper than coal or wood.) Thousands die of hypothermia because they can no longer afford proper heat.

In Germany, Greece and other countries, rising energy costs have caused a surge in illegal tree-cutting and wildlife poaching, as desperate families try to stay warm and feed themselves.

These realities portend what will likely happen on a far larger scale if Earth enters another prolonged cold era. Widespread turmoil, rising death tolls and climate refugees by the millions could become reality.

Climate modelers must get their predictions right so we can be properly prepared. That means basing models on all the forces that determine global temperatures and climate fluctuations: the sun, cosmic rays, deep ocean currents, volcanoes and other powerful natural forces — not just carbon dioxide, which represents a mere 0.04 percent of Earth's atmosphere.

It means comparing predictions with actual real-world observations and data. If the models still do not predict accurately, modelers must revise their hypotheses and methodologies yet again, until forecasts square with reality.

Meanwhile, politicians must base energy policies on how Earth's climate and weather actually behave — and on how laws and regulations affect jobs, economic growth, and human health and welfare, especially for poor and middle-class American families and the poorest people on our planet.

• Paul Driessen is senior policy analyst for the Committee For A Constructive Tomorrow (CFACT.org), author of "Eco-Imperialism: Green Power — Black Death" (Merril Press, 2010), and coauthor of "Cracking Big Green: Saving the World from the Save-the-Earth Money Machine" (CFACT, 2014).

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DOCUMENTS SUBMITTED BY REPRESENTATIVE EDWARDS

December 4, 2015

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

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

Dear Administrator McCarthy:

We, the undersigned physicians, nurses, and health professionals, strongly support the U.S. Environmental Protection Agency's proposed rules to reduce industrial methane and volatile organic compounds (VOCs) from new oil and gas sources. These standards will not only help to mitigate climate change and its associated health risks by curtailing emissions of methane – an especially potent greenhouse gas – from new and modified sources, but will also limit emissions of toxic and carcinogenic air pollutants, benefiting public health in communities across the country. Furthermore, we call on EPA to develop standards to limit similar emissions from existing sources as well, to truly protect public health.

Climate change poses grave threats to public health. The changing climate threatens the health of Americans alive now and in future generations. Growing evidence over the past few years has demonstrated the multiple, profound risks that imperil the lives and health of millions (AAP, 2015, Luber et al., 2014; Pinkerton et.al, 2013; APHA, 2011; TfAH, 2009). Consequently, the nation has a short window to act to reduce those threats.

To protect our children, our communities and the public, the United States must significantly reduce greenhouse gases. Methane is a powerful greenhouse gas. Reducing methane is an essential step to reduce the burden of climate change, but the benefits go far outside the impact on the climate. Lifesaving benefits to public health can begin immediately.

Comprehensive methane standards would immediately reduce emissions of volatile organic compounds (VOC), which include gases recognized as hazardous air pollutants. Six organic hazardous air pollutants dominate the mass from oil and natural gas extraction and can most harm human health: benzene, toluene, carbonyl sulfide, ethylbenzene, mixed xylenes, and n-hexane. (EPA, 2015). Benzene and formaldehyde, another hazardous pollutant from oil and gas emissions, are recognized as known human carcinogens, while ethylbenzene is considered a probable carcinogen (HHS, 2011).

VOCs are also precursors to the formation of ozone when they react with nitrogen oxides in the presence of sunlight. By limiting emissions of VOCs, the proposed oil and natural gas standard will reduce the amount of ozone formed in the air and, consequently, the incidence of ozone-related health effects, including asthma attacks, hospital admission and premature deaths (EPA, 2013).

Some VOCs are also precursors to the formation of fine particulate matter, PM2.5. PM2.5 causes respiratory and cardiovascular harm, lung cancer and premature death (EPA 2009, Hamra, et al., 2014). Reducing emissions of VOCs will reduce the PM2.5 in the atmosphere, as well as decreasing the risk of asthma attacks, heart attacks and premature death from the PM2.5 (EPA, 2015).

Curtailing these emissions would particularly reduce the exposure to those most vulnerable.
A growing body of peer-reviewed science indicates that oil and gas development is associated with adverse health impacts, including premature birth, congenital heart defects, neural tube defects, and low birth weight for infants born to mothers living near natural gas development (Casey et al., 2015; McKenzie et al., 2014; Stacey et al., 2015). One recent analysis found that, as of June 2015, 84 percent of all peer-reviewed original research since 2009 on public health and modern oil and gas development suggested potential public health risks or actual adverse human health impacts (Hays and Shonkoff, 2015; Shonkoff et al., 2014).

People most at risk of harm from breathing these air pollutants from the oil and natural gas industry include: infants, children and teenagers; older adults; pregnant women; people with asthma and other lung diseases; people with cardiovascular disease; diabetics; people with low incomes; and healthy adults who work or exercise outdoors. Many live and work in communities near these oil and gas facilities, which are often located near lower income or minority communities.

The growing problem of methane in the atmosphere indicates that existing oil and gas infrastructure currently produce higher methane emissions than have been estimated (Brandt et al., 2014). One recent report estimated that nearly 90 percent of projected emissions from oil and gas development in 2018 will come from existing infrastructure (ICF, 2014). We need comprehensive rules that cover existing oil and gas wells and infrastructure to reduce methane emissions and the impact on climate. We unite in urging EPA to move quickly to address emissions from existing sources as well.

Sincerely,

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September 28, 2016

Dr. Richard W. Spinrad
Chief Scientist, National Oceanic and Atmospheric Administration (NOAA)
Herbert C. Hoover Building, Room 51027
1401 Constitution Avenue, NW
Washington, DC 20230

Dear Dr. Spinrad,

On September 15, 2016, the Committee on Science, Space, and Technology Environment Subcommittee held a hearing titled "*A Solution in Search of a Problem: EPA's Methane Regulations*."

In the course of the hearing, one of my colleagues referenced a NOAA study, stating:

"A study published earlier this year by National Oceanic and Atmospheric Administration (NOAA) scientists found that the expansion in oil and gas production is not to blame for a global increase in methane emissions, and according to the study's author, 'the U.S. energy industry contributes little to the overall burden of global fossil fuel emissions.' According to this NOAA study, wetlands, which naturally generate methane, and agriculture, from sources outside the United States, are the main contributors to emissions."

NOAA was not present at the hearing to clarify its position. Therefore, I am requesting a formal comment from the Agency to address these remarks.

Specifically, I would like to know: 1) What is NOAA's position on how the U.S. energy industry contributes to global fossil fuel emissions? 2) Does the quote from the study's author accurately reflect the views of the Agency? 3) Do the above remarks accurately characterize the findings of the study, and the position of the Agency?

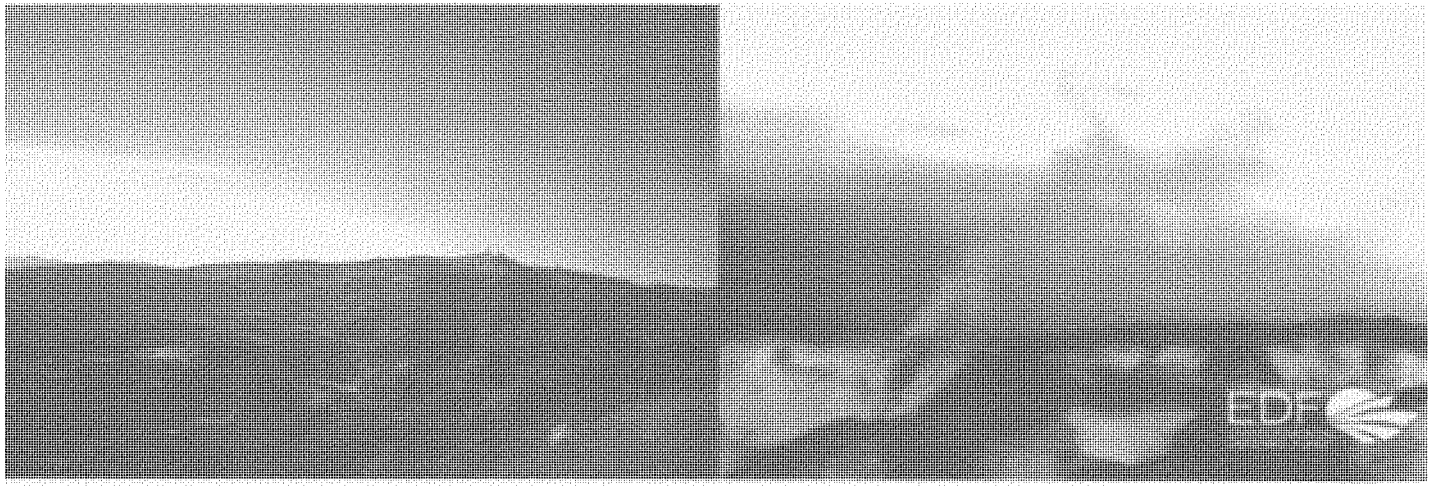
Thank you in advance for your attention to this matter.

Sincerely,

Suzanne Bonamici

Suzanne Bonamici
Ranking Member
Subcommittee on Environment

Infrared Camera Reveals Huge, Wafting Cloud of Methane over California's Aliso Canyon
Published: December 10, 2015



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THE POLITICS AND BUSINESS OF CLIMATE CHANGE

SCIENCE:

Oil and gas boom not to blame for methane spike -- study

Gayathri Vaidyanathan, E&E reporter

Published: Friday, March 11, 2016

Correction appended.

The U.S. oil and gas industry has boomed in recent years, but the expansion has not resulted in a global spike in methane levels, finds a landmark new study.

The **study** comes on the heels of a new pledge by President Obama yesterday to expand regulations of the energy industry to cut down leaks of methane, a potent greenhouse gas that is the primary component of natural gas.

Methane warms the Earth at 86 times the rate of carbon dioxide over the two decades it stays in the atmosphere. The United States and Canada plan to cut methane emissions by 40 to 45 percent below 2012 levels by 2025, and the oil-sector regulations are a major piece of that effort (***see related story***).

But the research, published yesterday in *Science*, finds policymakers might make more progress on global warming if they focus on curbing emissions from agriculture or animal husbandry, primarily in the tropics.

"Currently increasing methane levels are caused not by fossil fuel production but rather by wetlands or, more likely, agriculture," said Hinrich Schaefer, an atmospheric scientist at the National Institute of Water and Atmospheric Research in Wellington, New Zealand, and lead author of the study.

"That means we have to find ways to reduce methane emissions from rice agriculture, beef and dairy farming while still feeding the world's population if we want to mitigate climate change," he said.

Lori Bruhwiler, a physical scientist at the National Oceanic and Atmospheric Administration's Earth System Research Laboratory, called the study "important."

"Many of us were waiting for a paper like this to come out," she said.

'Circumstantial' evidence of gas well contributions?

The study deals with one of the enduring puzzles about the planet's atmosphere. Historical records show methane levels have been steadily rising since the Industrial Revolution. In the 1970s and 1980s, methane levels climbed by 12 parts per billion every year.

The rise abruptly stopped in the 1990s as nations stabilized their emissions. Then, around 2007, methane levels began growing once again. About 17 teragrams more methane is now emitted every year compared to the annual emissions between 2000 to 2006.

Scientists have been trying to identify the source of the methane, a challenging task because there are so many potential sources. Anaerobic bacteria in wetlands decompose vegetation and release methane. The gas also escapes from cows and manure lagoons on dairy farms, from submerged rice fields, from coal fields, and from leaky equipment on oil fields.

The latter source has seemed particularly suspicious. The United States has experienced an oil and gas boom since 2005 and vaulted over Russia in 2014 to become the world's top producer.

"[People] are pointing at the U.S. because it is well-known that production in the U.S. has increased dramatically," said Bruhwiler. "It's a little bit circumstantial."

To hammer down the contributions of the various sources, Schaefer and his colleagues used a fingerprinting technique. There are two types of methane in the air, one with a heavier carbon atom and the other with a lighter one. Scientists can look at the mix of heavy and light carbon atoms in a sample and deduce the origins of the gas.

Schaefer and his colleagues analyzed methane samples from around the world and from Earth's history, embalmed as air bubbles in ice cores drilled from the poles.

Enviros say science doesn't undercut policy

The samples collected since 2006 gave unexpected results. The analysis suggested that fossil fuel production is not the major driver of the recent methane uptick. Rather, emissions from other human activity -- agriculture and dairy farming -- are. Schaefer called the results "surprising."

Greenhouse gas inventories from U.S. EPA show that emissions from fossil fuel extraction have increased in recent years. But this has apparently not registered on the global scale. This is possibly because the U.S. energy industry contributes little to the overall burden of global fossil fuel emissions, Schaefer said.

He stressed, however, that all progress in curbing carbon emissions is desirable.

"I'd like to add that any methane emissions are a problem for climate change and that even if oil and gas exploration don't contribute to rising methane levels, they certainly increase carbon dioxide, which stays in the atmosphere much longer," he said.

Steven Hamburg, chief scientist at the nonprofit Environmental Defense Fund, was cautious about the policy implications of the study. The advantages of reducing fossil fuel methane leaks are "not undercut in any way by the results here," he said.

All opportunities to curb emissions should be taken advantage of, he said. Moreover, other scientists are also studying the reasons behind the global rise in methane, and the knowledge base is still building.

"I wouldn't treat any single [study] as definitive," he said.

Rice field microbes possible culprits

Officials with the oil and gas industry, meanwhile, embraced the findings.

"Even as oil and natural gas production has risen dramatically, methane emissions have fallen, thanks to industry leadership and investment in new technologies. These industry-led efforts are a proven way to reduce methane emissions from existing sources, and they are clearly working," said American Petroleum Institute Vice President of Regulatory and Economic Policy Kyle Isakower.

Other scientists have looked at the levels of other gases, such as ethane and propane, which are emitted with methane during oil and gas production. Their preliminary research has suggested large increases of those gases, and therefore methane, over North America.

Schaefer's study suggests that something changed in the tropics around 2007. Microbes in submerged rice fields or in the stomachs of ruminants could be responsible. India, China and Southeast Asia are major rice and livestock producers and could be responsible, the authors suggest.

Bruhwiler said that wetlands could be a source, as well. When wetlands in the tropics and mid-latitudes are warm and wet, bacteria produce more methane. Climate change is expected to make these regions warmer and wetter -- a feedback that may have already kicked in, she said.

"If we are ever going to control emissions to stave off climate change, we need to understand what the emissions are and how they are changing over time," she said.

Correction: *An earlier version of this story misstated the rate of methane rise since 2007. It is 550 teragrams per year, 17 teragrams more than the rate between 2000 and 2006.*

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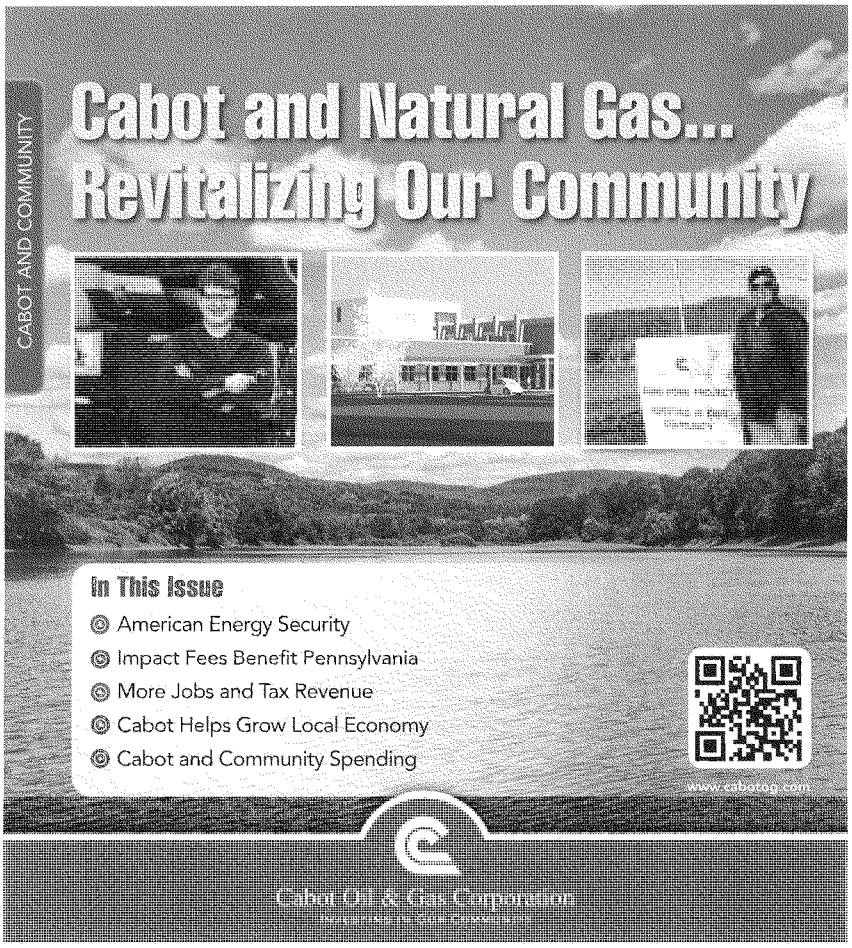
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A New Chapter in American Energy History

Thanks to natural gas production throughout the Marcellus Shale, Pennsylvania is playing a major part in helping our nation increase its energy security while helping protect against dramatic swings in natural gas price. In fact, Citigroup Inc. says this new "reindustrialization" of America could add as many as 3.6 million jobs by 2020 and increase the gross domestic product by as much as 3 percent.

Terms around the Industry

Ethane Cracking creating ethylene by breaking up oil and gas into smaller molecules

Pennsylvania's Amazing Economic Rebirth

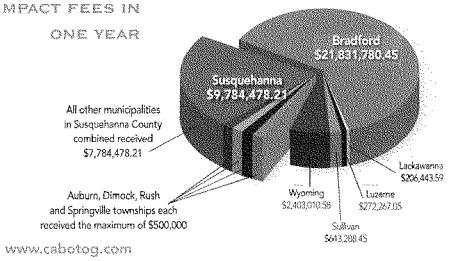
It's no secret that Pennsylvania and so many of its counties have already benefited tremendously from the financial benefits of natural gas production. But the latest numbers are truly astounding and indicate that Pennsylvania is heading toward a welcome economic windfall for decades to come.

Over $200 Million Paid in Impact Fees

State officials recently announced that Pennsylvania received $204 million in impact fee revenue from natural gas well production in 2011. Impact fees are placed on every well that's drilled within the Marcellus Shale in Pennsylvania. Sixty percent of the money raised goes to counties and local municipalities. The rest will be distributed through a legacy fund for a variety of statewide programs.

$500,000 IS THE MAXIMUM AMOUNT A MUNICIPALITY CAN RECEIVE IN IMPACT FEES IN ONE YEAR

2011 Impact Fee Dollars County-Wide



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What Can Impact Funds Be Used For?

Local counties and municipalities may spend funds on various expenses related to impacts from natural gas development, including:

- Construction, repair and maintenance of roads and other public infrastructure
- Water and sewer system construction and repair
- Emergency response preparedness and treatment
- Preservation and replacement of surface and subsurface water supplies
- Projects that increase the availability of affordable housing
- Delivery of various social services
- Assistance to county conservation districts for oversight and enforcement of natural gas development
- County or municipal planning

More Jobs and Increased Tax Revenue

Today, nearly 240,000 Pennsylvanians are directly and indirectly employed within the oil and gas industry. And over $1.6 billion in corporate, sales and personal income taxes have been generated by the industry since 2006 – including $420 million in 2011 alone. Just as exciting is a recently announced plan to build an ethane cracker plant in Pennsylvania that The American Chemistry Council says could add up to 20,000 direct and indirect jobs.

Local Businesses Are Thriving

The success of the natural gas industry is having a positive affect on a variety of local businesses throughout Pennsylvania – from water recyclers and environmental consulting firms to landscapers, hardware stores, insurance companies, real estate brokers, hotels, restaurants and more. The economic boon is also giving rise to new businesses and entrepreneurs who are finding novel ways of providing customized services to our industry and growing workforce.

Lower Energy Bills for Pennsylvanians

Another benefit of the natural gas industry is cheaper energy. The abundance of natural gas has driven electric and natural gas prices down nearly 40 percent since 2008, saving Pennsylvania businesses and consumers over $2 billion annually. After importing 75 percent of its natural gas just five years ago, Pennsylvania is now a net exporter of gas for the first time in more than 100 years.

PENNSYLVANIA WON A $15 MILLION FEDERAL GRANT FOR GAS INDUSTRY WORKFORCE DEVELOPMENT

Cabot...Building a Sustainable Local Economy

At Cabot, we're committed to helping our community build a strong economy with good family-sustaining jobs for generations to come. To that end, we've invested over $2 billion dollars in Susquehanna County, employed over 400 local residents in well paying jobs and supported hundreds of more citizens by partnering with local companies who help service our efforts to develop clean-burning natural gas.

Cabot Community Spending Tops $3,000,000

Because we work and live in Susquehanna County, it's important that we give back to our community and help improve the quality of life here. To that end we've given $3,188,312 to worthy local causes so far. This includes a $2.2 million donation to Endless Mountains Health Systems to help bring their dream of a new hospital facility to life. And to help sustain the county's physical infrastructure, we've spent more than $21,300,000 in helping build, improve and maintain roads throughout the region.

Helping America To Grow Stronger

At Cabot, we're proud to be named one of the top producers of natural gas in Pennsylvania. Because that means we're doing our part to restore America's domestic energy capabilities and help rebuild our local and national economies in the process.

3

To learn more about how impact fees are broken down, use your smartphone to scan this QR code.

www.cabotog.com

George Stark

Director of External Affairs

Born and bred in Pennsylvania, George Stark worked in various public relations, governmental affairs and public policy positions throughout the Commonwealth before joining Cabot in 2010. Since then, George has become the public face of our company in Susquehanna County – overseeing the coordination Cabot's large events and driving the company's public relations efforts in the region. The position requires George to frequently interact with the public and media while engaging with a range of differing viewpoints.

Although the job presents many challenges, it fulfills George's life-long passion for community relations. "I like communicating the virtues and benefits of natural gas usage and educating the people about what Cabot does," he says. He also enjoys the fast pace of his job. "I have the privilege of dealing with many different cases on a daily basis, which is why I say there's never a dull moment," he adds.

George is fond of the residents and not so fond of Susquehanna County, noting that "the people are extremely friendly and the county has a wonderful history. I love exploring and learning about it with my family."

Cabot Oil & Gas Corporation

INVESTING IN OUR COMMUNITY

Cabot Oil & Gas Corporation is an independent natural gas producer and a leading developer of the natural gas supply contained in the Marcellus Shale in Susquehanna County, Pennsylvania.

VISIT WWW.CABOTOG.COM TO LEARN MORE.

Discover more of Cabot's Community Giving in our

Next Issue

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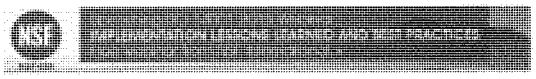

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April 20, 2016

Oil Industry Calls EPA's Methane Emissions Inventory 'Seriously Flawed'

By: Jessica Lyons Hardcastle

The oil industry is striking back against an EPA report that says methane emissions from the oil and gas sector are higher than previously estimated.

On Friday, the EPA published its annual greenhouse gas emissions inventory that it submits to the United Nations.

The inventory shows a 9 percent drop in emissions since 2005 and a 1 percent increase in emissions in 2014 from 2013 levels. The report also includes a major revision to its estimates of methane emissions.

While last year's report suggested that the US' highest source of methane was cattle and other farm animals — not the oil and gas industry — this year's says the oil and gas sector is the largest emitting-sector for methane and accounts for a third of total US methane emissions.

The EPA revised total US methane emissions for 2013 from 636.3 million metric tons to 721.5 million metric tons. For 2014, the most recent year in the report, the EPA says methane emissions reached 730.8 million metric tons.

In a call with reporters, Kyle Isakower, American Petroleum Institute vice president of regulatory and economic policy, called the EPA industry flawed. "We're concerned the administration is putting politics ahead of science by turning the numbers on their head," Isakower said. "EPA's inventory has consistently shown a downward trend in emissions even as oil and natural gas production has soared. Somehow, in this year's inventory, using a flawed new methodology, EPA has erased that progress from its historic data."

The most recent greenhouse gas inventory comes as the Obama administration has set a goal of reducing methane emissions by 40 percent to 45 percent from 2012 levels by 2025. Last summer the EPA proposed new rules to limit methane emissions from new and modified sources in the oil and gas sector and said this month it will begin developing regulations to limit these releases from existing oil and gas wells.

Meanwhile 41 energy companies — including Duke Energy, National Grid and TransCanada Pipelines — have agreed to voluntarily reduce their methane emissions as part of an EPA partnership program launched last month.

Don't miss our Environmental Leader 2016 Conference in June.

- EPA Escalates Oil & Gas Methane Emissions Crackdown
- White House to Cut Methane Emissions from Oil, Gas
- The Future of Natural Gas Depends On How Well the Industry Can Capture Methane Releases
- EPA Won't Regulate Coal Mine Emissions
- Testing for Gases in Water Simplified

Energy Manager News

Poetic Justice for the Constitution Pipeline?

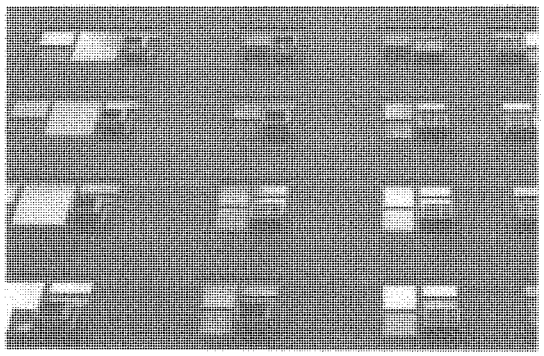
naturalgasnow.org/poetic-justice-constitution-pipeline/

By Tom Shepstone 8/19/2016

Tom Shepstone
Shepstone Management Company, Inc.

The Constitution Pipeline is getting some poetic justice, as Andrew Cuomo is forced to address an energy situation that requires more than his bandaids.

Poetic justice may be the sweetest of all, even if sometimes fleeting. The Constitution Pipeline is getting some right now. Electricity providers in both New York and New England have been telling Andrew Cuomo and others governors they need more access to natural gas. That means the Constitution Pipeline. Cuomo, in a craven act of subservience to the NRDC gang, refused to allow his Department of Environmental Conservation (DEC) to issue a routine permit for this necessary infrastructure. Now, a heat wave has forced him to call for conservation. How sweet it is! Well, not really.



Here's what the New York Independent System Operator (NYISO) said recently (emphasis added):

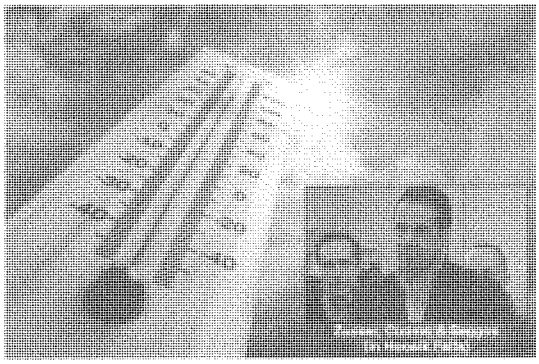
> *The interaction between natural gas infrastructure and the power grid is coming under sharp focus as* ***any disruptions in generator access to natural gas may increasingly have consequences for grid reliability****. The increase in gas demand for electric generation, the economic pressure the state's nuclear units are facing as a result of low gas prices, and uncertainty over the likelihood of gas infrastructure expansions all contribute to* ***strategic concerns over the gas system's ability to***

> ***meet the future coincident requirements of gas-fired generation as well as residential, commercial and industrial gas customers, especially on winter and summer peak demand days.***

It was a clear message to policy-makers to bring on the Constitution Pipeline and others like it or face the consequences. The consequences have already arrived. A faithful reader of *NaturalGasNOW* received an e-mail form of a press release from NRDC panderer-in-chief Cuomo saying this, among other things:

> ***GOVERNOR CUOMO DIRECTS IMMEDIATE CUTS TO STATE ENERGY USAGE AMID THIS WEEKEND'S HEATWAVE***
>
> ***Governor Urges Public and Local Governments to Follow Suit, Protect New York's Energy Grid***
>
> *Governor Andrew M. Cuomo today directed state agencies to take immediate steps to lower electricity usage in New York State due persistent high temperatures and humidity expected today and through the weekend.* ***All state agencies have been directed to immediately lower energy usage*** *by turning off lights, raising air conditioning temperatures, closing window shades, and powering down unused computers, printers and other electrical devices;* ***other regions were put on notice that they might have to do the same later in the day****.*
>
> *"This extreme heat has led to near-record electricity usage and* ***has placed significant demands on our entire grid,*****"** *Governor Cuomo said. "As temperatures remain high, I'm once again directing state agencies to take steps to conserve energy and reduce demands on the system. I encourage all New Yorkers to do the same."*
>
> *During heat waves, increased usage of electric devices such as air conditioners place a considerable demand on the state's electricity system and instances of low voltage or isolated power outages can result. The record for such usage was set on July 19, 2013 when it reached 33,955 MWs (One megawatt of electricity is enough to power up 1,000 average-sized homes). As a result of yesterday's high temperatures, the state's peak load approached the record with 32,076 MWs. Today's peak load forecast is 32,800 MWs.*
>
> ***The Governor also strongly encouraged local public officials, municipalities and the public to follow suit.*** *Consolidated Edison, the State's largest utility, implemented its commercial demand reduction program at 12 PM. This Department of Public Service-approved program is put in place to reduce electricity demand when it begins to rise rapidly…*
>
> ***Excessive heat is the leading cause of preventable, weather-related deaths each year, particularly among the elderly.*** *According to the federal Centers for Disease Control and Prevention, heat causes more than 650 preventable deaths in the United States yearly. In most years, excessive heat causes more deaths than floods, lightning, tornadoes, and hurricanes combined. According to National Oceanic and Atmospheric Administration and National Weather Service statistics, there have been more than 80 deaths directly attributable to heat in New York State since 2006…*
>
> ***The New York State Department of Health*** *created an online list of cooling centers, where people can cool down on days of extreme temperatures. A list of addresses and phone numbers for cooling centers shared by local health departments and emergency management offices in each region is available here.*

So, the Department of Health is now worried about deaths from heat? I thought it was hydraulic fracturing, which hasn't killed anybody or ever polluted a drinking water. Where's Howard Zucker these days, by the way? Stuck in Hoosick Falls? Cuomo was happy to use him to please the NRDC gang two years ago. Now, he's persona no grata. There's no mention, either, of the DEC after they did the gang's bidding on the Constitution Pipeline.



The NRDC gang, of course, isn't worried. They have second-homes up in the Catskill Mountains, after all, where they can go to stay cool. Moreover, their homes and offices on Manhattan already have a good supply of natural gas, so they'll be fine. The poor rubes upstate and in New England might suffer a bit, but those places might better be a wilderness for them to enjoy on cooler days anyway. So goes the thinking in that gang of elitist thugs. "Let them eat cake," they say.

Cuomo's call for using less air conditioning and warning of the dangers of too much heat while simultaneously trying to kill energy projects illustrates where all demagoguery ends; in disaster. He is a corrupt man-child with a talent for making the naive and politically correct believe he's somehow leading. Yeah, he's leading. He's leading from behind, trying to catch up with his own mistakes. It would be sweet poetic justice indeed if it weren't for what's at stake and the fate of New Yorkers forced to live with his lack of real leadership.

WESTERN ENERGY
ALLIANCE

December 4, 2015

Via Federal eRulemaking Portal: http://www.regulations.gov

Ms. Gina McCarthy
Administrator
U.S. Environmental Protection Agency
EPA Docket Center
Mail Code 2821T
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

Re: *Review of New Sources and Modifications in Indian Country: Federal Implementation Plan for Managing Air Emissions from True Minor Sources Engaged in Oil and Natural Gas Production in Indian Country* – Docket ID number: EPA-HQ-OAR-2014-0606

Dear Administrator McCarthy:

Western Energy Alliance submits the following comments on the U.S. EPA *Review of New Sources and Modifications in Indian Country: Federal Implementation Plan for Managing Air Emissions from True Minor Sources Engaged in Oil and Natural Gas Production in Indian Country* (referred to herein as the proposed FIP or National FIP).

The Alliance represents over 450 companies engaged in all aspects of environmentally responsible exploration and production of oil and natural gas in the West. Alliance members are independents, the majority of which are small businesses with an average of fifteen employees. The following oil and natural gas trade associations also sign in support of these comments:

American Exploration and Production Council
Idaho Petroleum Council
Independent Petroleum Association of America
Independent Petroleum Association of New Mexico
La Plata County Energy Council
Montana Petroleum Association
New Mexico Oil and Gas Association
North Dakota Petroleum Council
Oklahoma Independent Petroleum Association
Utah Petroleum Association

Many of our members operate in Indian country and require a streamlined permitting approach that is self-implementing and supports the responsible development of mineral resources on Indian Lands.

1775 Sherman St., Ste 2700 Denver, CO 80203
P 303.623.0987 F 303.893.0709 W WesternEnergyAlliance.org

Western Energy Alliance supports a number of components proposed in the National FIP. First, we support EPA's decision to use a FIP as the regulatory mechanism for this program. We agree with EPA's stated sentiment that "[t]he FIP would reduce burden for sources and the Reviewing Authority and prevent delays in new construction due to the minor NSR permitting obligation." 80 Federal Register 56557 (Sept. 18, 2015). Second, we support EPA's decision to focus on new sources, rather than existing sources, under the FIP. We agree that existing sources are best addressed in the context of area-specific rule-makings, at a time when the individual need arises. Third, we support EPA's strategy to align the FIP with existing Federal standards. As EPA stated in the proposal, there is value in relying on regulations that have been vetted through the public comment process and that operators have already committed to complying with. *See* 80 Fed. Reg. at 56569. Fourth, we thank EPA for its decision to extend the National FIP registration deadline from March 2, 2016 to October 3, 2016. This deadline extension will give operators much needed time to fully comprehend the new rule and prepare for future development in Indian country.

However, in order to establish a truly streamlined permitting mechanism that conserves the agency's resources and facilitates development in Indian country, EPA must make a number of revisions to the National FIP, as outlined below.

EPA Must Allow Other Federal Standards and Tribal Standards to Limit PTE

The National FIP states at 40 CFR § 49.102 Definitions: "As used in §§ 49.101 through 49.105, all terms not defined herein shall have the meaning given them in the Clean Air Act, in subpart A, and subpart OOOOa of 40 CFR part 60, in the Prevention of Significant Deterioration regulations at 40 CFR 52.21, or in the Federal Minor NSR Program in Indian Country at 40 CFR 49.152." The Alliance understands this incorporation to mean that EPA proposes to include the definitions of "Potential to emit" and "Enforceable as a Practical Matter" in 40 CFR 49.152 into the National FIP.

40 CFR Section 49.152 defines "Potential to emit" as:

> the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable as a practical matter. Secondary emissions, as defined at § 52.21(b)(18) of this chapter, do not count in determining the potential to emit of a source.

The definition above refers to limitations that are "enforceable as a practical matter." Section 49.152 separately defines "Enforceable as a Practical Matter" to mean enforceable by the "Reviewing Authority" or, in other words, EPA or a tribe delegated to implement the FIP.

EPA's definition of "Enforceable as a Practical Matter" in Section 49.152 conflicts with the D.C. Court ruling in *National Mining Ass'n v. EPA*, 59 F.3d 1351(D.C. Cir. 1995). It is important to be able to account for other enforceable limits because (1) EPA source-specific permitting for new sources and modifications can be burdensome and time-consuming; (2) NSPS and NESHAPs may not limit PTE in some instances (as discussed below) and (3) EPA has not created synthetic minor limits in this FIP nor created a mechanism in this FIP to obtain limits in a streamlined manner. Other limits include limits imposed by the BLM or a Tribal authority. EPA's definition of "Enforceable as a Practical Matter" would not allow consideration of those limits. The D.C. court ruled that EPA must consider those other enforceable limits.

Accordingly, EPA should revise 40 CFR 49.152 "Enforceable as a practical matter" to read: Enforceable as a practical matter means that an emission limitation or other standard is both legally and practicably enforceable as follows:

> (1) An emission limitation or other standard is legally enforceable if a government authority, federal or tribal, has the right to enforce it.

The National FIP Should Fill Existing Gaps in the Permitting Program for True Minor and Synthetic Minor Sources in Indian Country

The FIP as proposed does not provide any means for owners and operators to voluntarily obtain enforceable emission limitations on potential to emit (PTE). Owners and operators of stationary sources located within Indian country will be forced to seek such limitations via the existing synthetic minor permitting process. Furthermore, a number of emission sources common in the oil and natural gas production sector are not subject to the six Federal standards adopted in the National FIP and therefore, there is no mechanism to obtain federally enforceable emission limits for such sources outside of site-specific permitting or the synthetic minor permitting process. Please note the following examples:

- Storage vessels not subject to NSPS
- Flares burning separator/treater gas (no NSPS/NESHAP applies to separators) that, without enforceable controls, may exceed major source thresholds in and of itself
- Heaters not located at major sources of HAP and not subject to NESHAP DDDDD
- Engines grandfathered from NSPS and not subject to control requirements under NESHAP ZZZZ
- Area source glycol dehydration units not subject to controls under NESHAP HH
- Pneumatic pumps grandfathered from the forthcoming NSPS OOOOa

EPA has set precedent with policies to develop general permits, permits by rule and FIPs for common types of emissions units and minor sources to streamline the permitting

process. Take, for example, the Fort Berthold Indian Reservation (FBIR) FIP. 78 Fed. Reg. 17836 (Mar. 22, 2013). EPA promulgated a reservation-specific FIP "to establish enforceable control requirements for reducing VOC emissions from oil and natural gas production activities on the FBIR in North Dakota." Id. at 17838.

The FBIR FIP interim final rule provides a helpful explanation for the FBIR FIP's utility and value:

> "[O]wners and operators of oil and natural gas operations producing from the Bakken Pool on the FBIR are potentially subject to the Federal preconstruction permitting requirements found in the Federal rules at 40 CFR 52.21 (Prevention of Significant Deterioration of Air Quality), and 40 CFR 49.151 through 49.161 (Federal Tribal NSR Rule). However, on the FBIR only NSPS OOOO and NESHAP HH provide legally and practicably enforceable VOC control requirements outside of the Federal pre-construction permitting requirements. Further, NSPS OOOO only applies to new and modified facilities and only to the oil storage tanks being utilized in the Bakken Pool operations. Thus, most owners and operators of oil and natural gas activities producing in the Bakken Pool must obtain preconstruction permits before production can begin, or if they are not obligated to obtain a permit face no control obligations whatsoever."

77 Fed. Reg. 48878, 48882 (Aug. 15, 2012).

Owners and operators of production facilities within areas of Indian country outside of the FBIR face a similar regulatory gap. Only NSPS OOOO and NESHAP HH provide legally and practicably enforceable VOC control requirements outside of the Federal pre-construction permitting requirements. Similarly, only certain NSPS and NESHAP standards provide legally and practicably enforceable control requirements for regulated NSR pollutants other than VOC that are or may be emitted from stationary internal combustion engines and other sources commonly used within the industry.

As explained in the preamble of the National FIP, "The FBIR FIP does provide legal and practical enforceability for the use of VOC emission controls..." 80 Fed. Reg. at 56567. These FBIR FIP control mechanisms provide operators with a predictable and reasonable timeline to permit new development. We request the option for these same types of legal and practically enforceable emission controls in the National FIP. Accordingly, we propose that EPA consider the following provisions:

Insert new section 49.106 to the National FIP providing:

(a) Sources not subject to NSPS or NESHAPs may elect to comply with a NSPS or NESHAP under this FIP as a mechanism to establish enforceable conditions on the source's potential to emit. Once the source elects to be subject to the NSPS or NESHAP, the NSPS or NESHAP are enforceable against the source under this FIP.

(b) (i) Sources may elect to be subject to one or more facility-wide emission limits listed below.
   a. 249 tons per year of any NSR regulated pollutant in an attainment area;
   b. 99 tons per year of any NSR regulated pollutant in any nonattainment area;
   c. 24 tons per year of total hazardous air pollutants;
   d. 9 tons per year of any single hazardous air pollutant;
   e. 99 tons per year of any regulated pollutant;

(ii) The facility-wide emission limits are 12-month rolling limits. Once a source elects coverage under this paragraph, the source must demonstrate compliance every month based on emissions of the prior 12 months.

(iii) Sources subject to this paragraph shall demonstrate compliance and determine emissions based on the monitoring and recordkeeping dictated in any NSPS or NESHAP for the types of equipment covered under the facility-wide emissions limit.

(iv) Sources subject to this paragraph shall monitor emissions and emissions-related data and keep records consistent with NSPS or NESHAP monitoring and recordkeeping for the types of equipment covered by the emissions limit for the purposes of compliance with this paragraph, even if such equipment is not subject to the NSPS or NESHAP.

The facility-wide emission limit proposed here is the preference for many operators. Additionally, the Alliance encourages EPA to offer flexibility to operators so they can select an approach best suited to their individual needs to fill the gaps identified in this section. Thus, the Alliance strongly encourages EPA to offer a menu of options to operators in order to ensure that the FIP contains robust yet flexible control measures, rather than a prescriptive, one-size-fits-all approach.

For some operators, limitations based on throughput, production, or hours of operations may be a useful approach. The Alliance suggests that in addition to the facility-wide emission limits proposed above, EPA also allow operators the opportunity to request synthetic minor status during registration of facilities in the form of requesting federal enforceability for limitations on production, throughput, or hours of operation for designated emission units. Operators would request synthetic minor status, identify the emission unit, identify the means of limitation (e.g. production limitation), and provide the numerical limitation. Operators would then have an obligation to maintain records of the chosen limitation on a monthly basis and provide those records to EPA upon request.

By example, an operator could designate a well site facility in its registration to EPA as requesting synthetic minor status with a limitation on annual oil production. The operator

would be required to designate the numeric annual oil production limitation and track oil production on a monthly basis. The oil production limitation would then become federally enforceable.

Without emission limits or limits on production, throughput and/or hours of operation within the National FIP to serve to limit the PTE for synthetic minor sources and synthetic minor modifications, an overwhelming number of operators in Indian country will have to obtain site-specific permits for future development. As a result, EPA will receive an overwhelming number of individual permit applications that will create an undue burden on the Agency and its resources. Furthermore, development efforts in Indian country will experience lengthy permitting delays and interruption in new construction, thereby disadvantaging production from Indian country compared to state and fee lands.

Minor Modifications at Major Sources Need the FIP Streamlined Process

The FIP should be available also for minor modifications at major sources and modifications at synthetic minor sources. EPA does not explain why the FIP is limited only to new and modified true minor sources. Minor modifications at major sources can be of the same size and type as modifications at minor sources. Similarly, modifications at synthetic minor sources can be the same as a modification at a true minor source. EPA unreasonably limits the FIP to modifications at true minor sources. Major sources and synthetic minors that might have already undergone the burden of source-specific permitting should not continue to be disadvantaged with source-specific permitting for minor modifications. EPA must revise language throughout the rule that refers modifications to true minor sources by removing "true" and allow the FIP to be used for modifications at any existing minor source and allowing the FIP to be used for minor modifications at any existing major source.

EPA must also revise paragraph A under the applicability section; 40 CFR §49.153(a)(1)(ii)(A) should state:

> For the pollutant being evaluated, determine whether your proposed modification is subject to review under the applicable major NSR program. If the modification at your existing major source does not qualify as a major modification under that program based on the actual-to-projected-actual test, it is considered a minor modification and is subject to the minor NSR program requirements, if the net emissions increase from the actual-to-projected-actual test is equal to or exceeds the minor NSR threshold listed in Table 1 of this section, except that modifications at oil and natural gas production sources shall instead comply with the requirements of the Federal Implementation Plan at §§ 49.101 to 49.105, unless you opt-out of the Federal Implementation Plan pursuant to § 49.101(b)(2) in which case you are subject to the preconstruction requirements of this program for that pollutant or are required by the EPA to obtain a minor source permit

pursuant to § 49.101(b)(3). For a modification at your existing minor source, go to Step 2 (paragraph (a)(1)(ii)(B) of this section).

The National FIP Must be Revised to Remove the Jurisdictional Overreach Regarding the Endangered Species Act and National Historic Preservation Act

We are concerned that EPA's requirements for additional analysis under the Endangered Species Act (ESA) and National Historic Preservation Act (NHPA) in the National FIP will lead to additional lengthy permitting delays. It is counterproductive to develop a nationwide FIP for permitting that includes site-specific individual determinations for each permitted location. Operators must already contemplate impacts to threatened and endangered species as well as cultural resources in development plans. This added, secondary layer of approval proposed by EPA will add delay and expense while duplicating existing protections for species and cultural resources.

As EPA states in the proposal preamble, "[a] FIP...has the advantage of not requiring a source to initiate advance review and obtain approval of coverage from the Reviewing Authority before beginning construction...and it would reduce the resource burden on reviewing authorities associated with processing the potentially large volume of requests...". 80 Fed. Reg. at 56568. Through the requirement to assess threatened and endangered species and historic properties under the FIP, EPA is compromising the very benefits of a FIP.

The Alliance is also concerned with the jurisdictional overreach of EPA regarding requirements related to threatened and endangered species and historic properties in the proposed regulations. As recognized in the proposed rule, an operator is required to obtain an Application to Drill (APD) on federal lands or lands held in trust by the federal government in order to conduct any oil and natural gas production activities. In order to obtain an APD, the operator must work with both the Bureau of Indian Affairs (BIA) and Bureau of Land Management (BLM) to conduct the necessary consultations required under the Endangered Species Act (ESA) and National Historic Preservation Act (NHPA) through the National Environmental Policy Act (NEPA) process. However, where there is no federal nexus, the EPA has no jurisdiction to require ESA or NHPA consultations. Therefore, Western Energy Alliance has concerns with the section in the proposed rule requiring operators to conduct a screening process for ESA and NHPA review before beginning construction under the proposed FIP on lands with no federal nexus. EPA is not a surface management agency and does not have jurisdiction under the ESA and NHPA on state and private lands.

Pre-Construction Registration is Unworkable

The inherently unpredictable nature of oil and natural gas production makes the pre-construction requirement proposed by EPA a burdensome requirement that will be of limited use to EPA and confusing to the public.

First, it is important to note that operators are unable to accurately determine their PTE prior to construction. A number of variables, some known and some unknown, will dictate how a well comes online and the level of emissions associated with production. For example, operators are constantly evaluating completion activities with an eye toward innovation. Within even a short amount of time, an operator may develop a more efficient completion process that may increase initial production and thereby potentially increase emissions. However, efficiencies may not be discovered until after the new process is attempted (i.e. post-construction). Accordingly, pre-construction registrations are essentially educated guesses.

Pre-construction emission estimates are of limited use to EPA. Such estimates are not accurate enough to be used in emission inventories and certainly cannot be relied on for the purposes of air quality modeling.

Finally, the inaccurate information and confusion created by a pre-construction registration will only be compounded when this information is made publicly available on EPA's website. Alliance members have observed instances where third parties have analyzed overstated PTE estimates, treating those numbers as actuals, which has led to overstated evaluations of oil and natural gas development's impact on airsheds.

In order to provide EPA and others with more accurate actual data, the pre-construction registration will need to be amended after construction once actual emissions have been determined. This revision will require duplicative work by operators, which is inefficient, costly, and offers no environmental benefit. Furthermore, EPA will be tasked with processing and reviewing duplicative submittals.

As a solution to this problem, instead of preconstruction registration, we urge EPA allow operators to register under the FIP by providing actual emissions data (based on the first thirty days of production) due within ninety days of the first date of production. A similar practice is already allowed by EPA under the existing N5PS OOOO rules. Several states also acknowledge the value in post-construction registration and/or permitting of oil and natural gas production facilities.

In Wyoming, oil and natural gas operators may commence operation and modification of a facility prior to obtaining an Air Quality Permit under Wyoming Air Quality Standards and Regulations, Chapter 6, Section 2, so long as the operator satisfies certain emission control requirements outlined in Wyoming Department of Environmental Quality's Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (last revised September 2013).

In Colorado, emission information related to new/modified oil and natural gas exploration and production operations (well site and associated equipment) is not required to be submitted to Colorado's Air Pollution Control Division until "after exploration and/or

production drilling, workovers, completions and testing are finished." See Air Quality Control Commission Regulation No. 3, Part A, Section II.D.1.III. In allowing the submission of emission data post-construction, Colorado's Air Quality Control Commission noted:

> Oil and gas exploration activities are activities for which it is difficult for the owner or operator to estimate what emission equipment will be required, and therefore what emissions will occur, until the exploration activities are already underway, and near completion. For this reason, the Air Pollution Control Division (Division) has extended a temporary exemption from APEN and permit requirements for such activities. Before commencing exploration activities, the source must notify the Colorado Oil and Gas Conservation Commission (COGCC). In this way, the Division is aware of the activities and will be able to address any concerns that are raised by the public.

Air Quality Control Commission Regulation No. 3, Part G, Statement of Basis, Section I.K (adopted June 22, 1993).

The North Dakota Department of Health provides a similar, post-construction registration process for operators in North Dakota. A completed oil and natural gas well registration form and gas analysis must be submitted to the Department of Health within ninety days of the completion or recompletion of a well. North Dakota Century Code Chapter 33, Section 15-20-02. The Department of Health recognizes that:

> ...emissions associated with the exploration and production of O&G resources cannot be predicted with any degree of precision or accuracy until after it is determined the oil or gas well will actually produce and site specific production data are collected and known. Therefore, unlike other stationary sources for which projected emissions upon startup can be estimated in advance for purposes of pre-construction air permitting, emissions from O&G exploration and production facilities are only known post-construction and completion.

North Dakota Department of Health, Bakken Pool Oil and Gas Production Facilities Air Pollution Control Permitting & Compliance Guidance (May 2, 2011).

Allowing oil and natural gas operators to provide emission information within ninety days of the first date of production under the FIP will conserve EPA resources and provide the agency with more accurate information.

EPA's Site-Specific Permitting Authority under the Proposed National FIP Is Overly Broad and Potentially Exceeds Agency Authority

Western Energy Alliance is concerned with EPA's proposal to require minor site-specific permits on a case-by-case basis, in lieu of the streamlined registration process provided in the National FIP. The proposal grants EPA with overly broad and unrestricted discretion to

require site-specific permits. Proposed 40 CFR Section 49.101(b)(3) provides that EPA may require owners and operators of oil and natural gas production facilities to obtain a site-specific permit "to ensure protection of the NAAQS." 80 Federal Register 56564, 56573 (Sept. 18, 2015). EPA further expands on its discretion in the preamble stating, "the Reviewing Authority may determine that the source is not sufficiently controlled under the proposed FIP to protect the NAAQS in the area of the proposed project (e.g., if the measured design value for the area is close to or above the level of the NAAQS). In that circumstance, the Reviewing Authority can require the minor source to obtain a site-specific permit." 80 Fed. Reg. at 56564. The authority laid out in this proposal to require site-specific permitting is too broad.

We question EPA's authority to impose site-specific permitting requirements in areas that have not yet been officially designated out of attainment of the National Ambient Air Quality Standards (NAAQS) for any criteria pollutant standards. Further, in light of the recently lowered NAAQS for ozone of 70 ppb, a substantial number of areas in Indian Country may now be deemed "close to" the standard, triggering EPA's discretion to require site-specific permits. Site-specific permitting in areas "close to" the standard will disadvantage development in Indian country as it relates to development in state airsheds. While Indian country development will be stifled by site-specific permitting timelines, development in the state airshed will be supported through existing, state-created general permitting schemes for minor sources.

Note that states have set parameters around the state discretion to impose source-specific obligations, including air quality impact analysis for minor sources. For example, Arizona limits discretion as follows "The Director shall make such a request [for an air quality impact assessment], if there is reason to believe that a source or minor NSR modification could interfere with attainment or maintenance of a standard. In making that determination, the Director shall take into consideration: 1. The source's emission rates. 2. The location of emission units within the facility and their proximity to the ambient air. 3. The terrain in which the source is or will be located. 4. The source type. 5. The location and emissions of nearby sources. 6. Background concentrations of regulated minor NSR pollutants." Arizona Administrative Code Title 18, Chapter 2, Section R18-2- 334(E)(1)-(6). EPA has proposed no limits on EPA discretion nor described any objective parameters or the factual basis for exercising such discretion.

EPA's proposal preamble further provides, "[t]he agency recommends at the time of registration, the owner/operator of all new sources or all sources scheduled for modification contact the Reviewing Authority for a review of the air quality status of that area, and the possibility of a requirement for a site specific permit." 80 Fed. Reg. at 56564. Such a recommended practice slows down the permitting process, calls on additional agency resources, and runs counter to the principles of a streamlined registration process. We implore EPA to honor one of the core benefits of the National FIP – a streamlined registration scheme for minor emission sources – and not eclipse such a benefit by declaring the right to require site-specific permitting in a broad and unrestricted manner.

Accordingly, we urge EPA to remove the language cited above in the preamble and National FIP, granting the Agency unlawful authority to require site-specific permitting simply to "ensure attainment of the NAAQS," in areas where the measured design value is "close to" the relevant NAAQS and based on a case-by-case "review of the air quality in that area."

The National FIP Must Provide for Streamlined Permitting for Nonattainment Areas

As proposed, the National FIP does not cover nonattainment areas. "It [the FIP] would not apply to new and modified true minor sources that are located or expanding in referenced areas of Indian country designated nonattainment." 80 Fed. Reg. at 56557. Further, EPA fails to provide a transition for when an area goes from an attainment or unclassified designation to a nonattainment designation. Given the recently lowered ozone standard, this scenario is likely to play out in several areas of Indian country, most notably the Uinta Basin. Once a nonattainment designation is made, the only apparent registration/permitting mechanism is site-specific permitting for all minor sources of emissions.

Moreover, the Clean Air Act does not mandate any attainment planning for areas designated marginal nonattainment. Even for areas designated moderate nonattainment, attainment plans are not due until three years after the official designation. During this delay associated with any area-specific minor NSR nonattainment program, the source-specific permitting burden will increase for both major sources and minor sources. The major source threshold reduces from 250 tpy to 100 tpy and the minor source threshold decreases for VOCs from 5 tpy to 2 tpy. The number of source-specific permits will increase under any scenario for EPA simply based on the lower major source threshold.

As stated by EPA itself, it is not viable for EPA to deny coverage of this FIP for nonattainment areas "due to our inability to process hundreds of true minor source permits in an acceptable timeframe." 80 Fed. Reg. at 56568. For example, note EPA Region 8's receipt of over 6,000 oil and natural gas minor source registrations to date. In the other minor NSR streamlined permitting rules for Bundle 1, EPA included provisions that would allow continued use of streamlined permitting in nonattainment areas. See, 80 Fed. Reg. 25068 (May 1, 2015). EPA has provided no nonattainment options for oil and natural gas sources. Streamlined minor NSR in many states are available in nonattainment areas. By denying a FIP option for minor sources in nonattainment areas, EPA disadvantages oil and natural gas sources in Indian country.

EPA's Indian Country Minor NSR rule has lower minor NSR thresholds for nonattainment areas; for VOCs the threshold is 2 tpy rather than the 5 tpy for attainment areas. Thus, in nonattainment areas, the Indian Country minor NSR program applies to sources that would be exempt if they were in attainment areas. With the lower threshold, EPA's Indian Country minor NSR program covers more sources than it covers in attainment areas and more than other western states' minor NSR programs for attainment and nonattainment

areas. Arizona exempts sources from minor NSR that have emissions below 20 tpy of VOCs, New Mexico and South Dakota exempt sources below 25 tpy, Utah and Oklahoma exempt sources below 5 tpy. The proposed Indian Country oil and natural gas minor NSR FIP would not exempt from minor NSR any sources with emissions above the minor NSR thresholds and the Alliance is not asking EPA to revise the exemption threshold. However, the oil and natural gas minor NSR FIP should extend its streamlined authorization for new and modified minor sources and minor modifications at major sources to similarly sized sources in nonattainment areas.

Other western states apply the streamlined minor NSR program for oil and natural gas sources in nonattainment areas. Oklahoma's oil and gas PBR covers sources below 40 tpy of any regulated pollutant (except HAPs) and 10/25 tpy of HAPs. See Oklahoma Administrative Code, Title 252, Chapter 100, Subchapter 7-60.5(a)(1). Wyoming allows all sources with potential emissions below 100 tpy of criteria pollutants and 10/25 tpy of HAPs to begin construction or undertake a modification before obtaining a permit under Wyoming's Oil and Gas Presumptive BACT Permitting Guidance. Wyoming Department of Environmental Quality's Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (last revised September 2013). Colorado also has streamlined minor NSR programs that can be used in areas of nonattainment. By way of example see the following General Construction Permit examples in Colorado. They contain additional requirements for applications in nonattainment areas, so one can infer that they are accepted for use in the Denver-Julesburg Basin in Colorado's Front Range nonattainment area.[1][2]

To remedy these gaps, Western Energy Alliance urges EPA to provide for an expedited permitting mechanism for minor sources in nonattainment areas in the National FIP. EPA should allow owners/operators use of the National FIP for nonattainment permitting until a basin specific new minor source permitting program becomes effective under the implementation planning process to achieve attainment. An expedited permitting scheme for nonattainment areas in the National FIP would provide regulatory certainty for oil and natural gas operators, limit emissions, as necessary, during the transitional phase of designation and implementation planning and eliminate any disadvantage to the further, responsible development of oil and natural gas resources in Indian Country.

By denying coverage under the FIP for all sizes of minor sources and modifications, EPA imposes source-specific permitting for all emission increases without regard for their potential contribution or any reasonably available emission controls; for VOCs, this source specific permitting would apply to increases between 2 tpy and 99 tpy. As described above, states and EPA have acknowledged that even in nonattainment areas, there are levels of emissions that can be deemed insignificant even for nonattainment areas. The Alliance does not ask that EPA exempt all small sources from minor NSR but asks EPA to ensure some streamlined permitting approach in nonattainment areas. The Alliance is

[1] General Construction Permit GP01 Version 3, State of Colorado. May 15, 2013.
[2] General Construction Permit, GP07 Version 1, State of Colorado. April 17, 2014.

confident there is a mechanism to allow for development in nonattainment areas under the National FIP that will simultaneously ensure that new emissions do not cause or contribute to a NAAQS violation.

In conclusion, the Alliance reiterates the need for a streamlined, self-implementing National FIP for oil and natural gas development in Indian Country that covers both new minor sources and minor modifications at existing sources, allows for a mechanism to limit PTE, the inclusion of enforceable controls for synthetic minor sources, limited exceptions to FIP applicability, post-construction registration requirements, and a streamlined permitting mechanism for nonattainment areas. We thank EPA for the opportunity to comment on the proposed National FIP and would like to continue to work with EPA as it further develops this program. Please feel free to contact me regarding any questions with our comments.

Sincerely,

Kathleen M. Sgamma
Vice President of Government and Public Affairs

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The NATIONAL BUREAU of ECONOMIC RESEARCH

Monday, September 12, 2016

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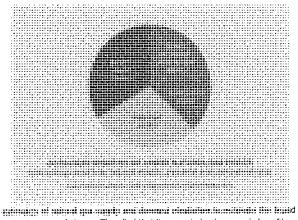
Welfare Implications of Falling Natural Gas Prices

Researchers estimate that falling U.S. natural gas prices between 2007 and 2013 generated consumer benefits of $74 billion in 2013 and reduced producer welfare by $26 billion annually.



Advances in horizontal drilling and hydraulic fracturing have allowed U.S. natural gas producers to profitably extract gas from shale formations previously considered uneconomic. From 2007 to 2013, production grew by more than 25 percent, leading to a sharp drop in prices. From 2000 to 2010, the average price of natural gas in the United States was $6.81 per thousand cubic feet in 2013 dollars. Since 2011, it has averaged $3.65 per thousand cubic feet.

In **Welfare and Distributional Implications of Shale Gas** (NBER Working Paper No. 21115), Catherine Hausman and Ryan Kellogg use new estimates of natural gas supply and demand elasticities to calculate the broad welfare and distributional effects of the natural gas supply boom. They find that it generated net economic benefits, not including environmental impacts, of $48 billion in 2013, which consists of a gain of $74 billion per year in consumer surplus benefits and a reduction of $26 billion per year in producer surplus benefits. As prices fall, this "consumer surplus" rises. A similar effect operates in the reverse direction for producers, though it is counteracted by the supply expansion itself. Some producers are able to extract natural gas for less than the prevailing market price, and they receive "producer surplus" as a result. When prices fall, the magnitude of this surplus declines. Natural gas producers with wells that were operating before the shale gas boom received lower revenues from their existing wells; therefore, states with large volumes of conventional natural gas production experienced declines in annual benefits to producers. Meanwhile, states such as Arkansas and Pennsylvania that experienced large increases in new shale production but had little conventional production saw increases in producer benefits.

The consumer surplus estimates suggest that lower prices created benefits of $17 billion per year to residential natural gas users, $11 billion per year to commercial users, $22 billion per year to industrial users, and $25 billion per year to electric power utilities. Benefits to commercial and industrial purchasers and to utilities ultimately accrue to those who purchase their products as well as to their employees and shareholders. The gains to these entities are therefore included in the $74 billion consumer surplus estimate.

Residents of the West South Central region—Arkansas, Louisiana, Oklahoma, and Texas—benefited most from the price decline because their industrial and electric power sectors use large amounts of natural gas. The estimated benefit in the region was $432 per person per year. Benefits in New England were $190 per person per year.

The results also suggest that low-cost natural gas stimulated manufacturing activity. The authors use data from the 2002, 2007, and 2012 Economic Censuses to compare the pre-boom period, 2002 to 2007, with the boom period, 2007 to 2012. They compare industries above and below the 90th percentile in their intensity of natural gas use, labeling the first group "highly dependent" on natural gas and the second group "less dependent." They find that industries that are highly dependent on natural gas contracted less during the post-2008 economic downturn, and increased rather than decreased employees' compensation, arguably—though not conclusively—as a result of the favorable shock to natural gas prices that coincided with the economy-wide recession.

Fertilizer manufacturers are the most intensive users of natural gas in the U.S. economy. From 2002 to 2007, fertilizer manufacturing establishments decreased by 9.5 percent and fertilizer manufacturing employment decreased by 15.8 percent. Between 2007 and 2012, however, fertilizer manufacturers increased employment by 8.6 percent, establishments by 8.3 percent, employee compensation by 24.8 percent, and capital expenditures by 232.7 percent. The authors report that low U.S. natural gas prices are also a driving force behind plans to increase U.S. ethylene production sharply.

— Linda Gorman

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Physician Practice Styles: Evidence from Cardiologist Migration

National Bureau of Economic Research, 1050 Massachusetts Ave., Cambridge, MA 02138, [illegible] email: info@nber.org

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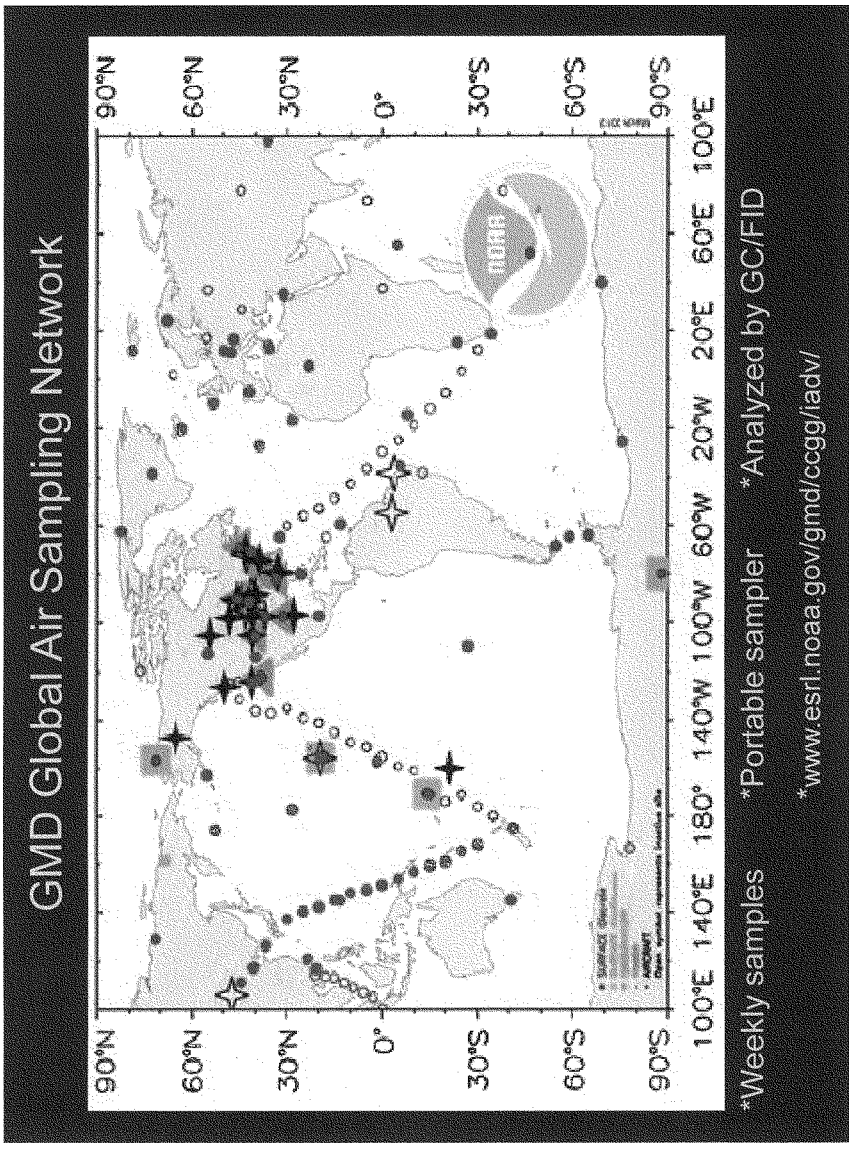
What have we learned from three decades of high-quality atmospheric CH_4 measurements?

NOAA Global Monitoring Division

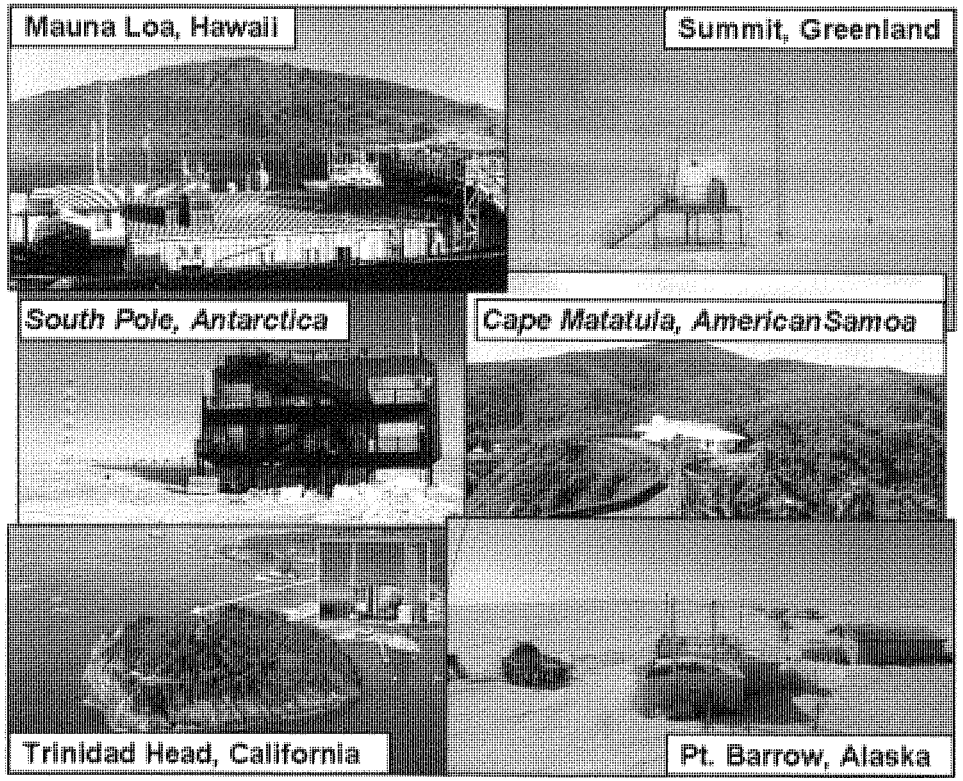
NOAA Earth System Research Laboratory

Boulder, Colorado USA

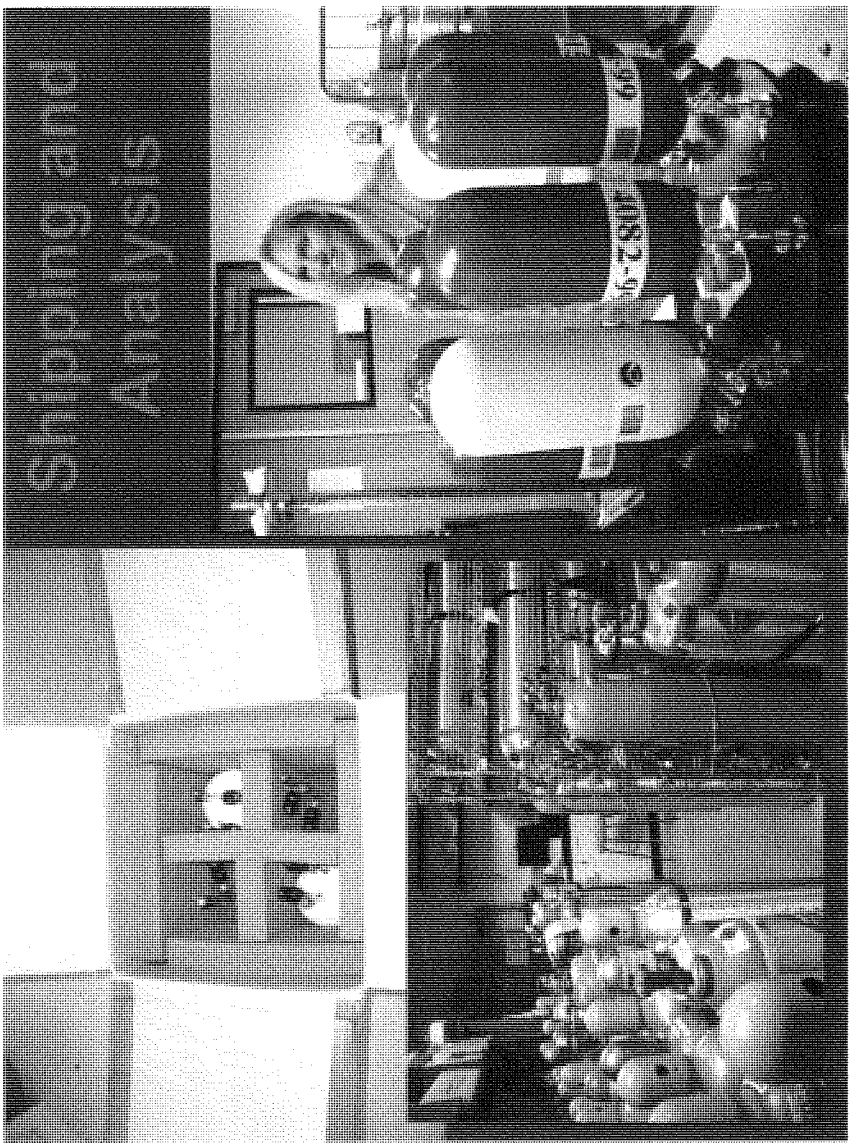
Presented by C. Ross Scientific, June 6, 2019

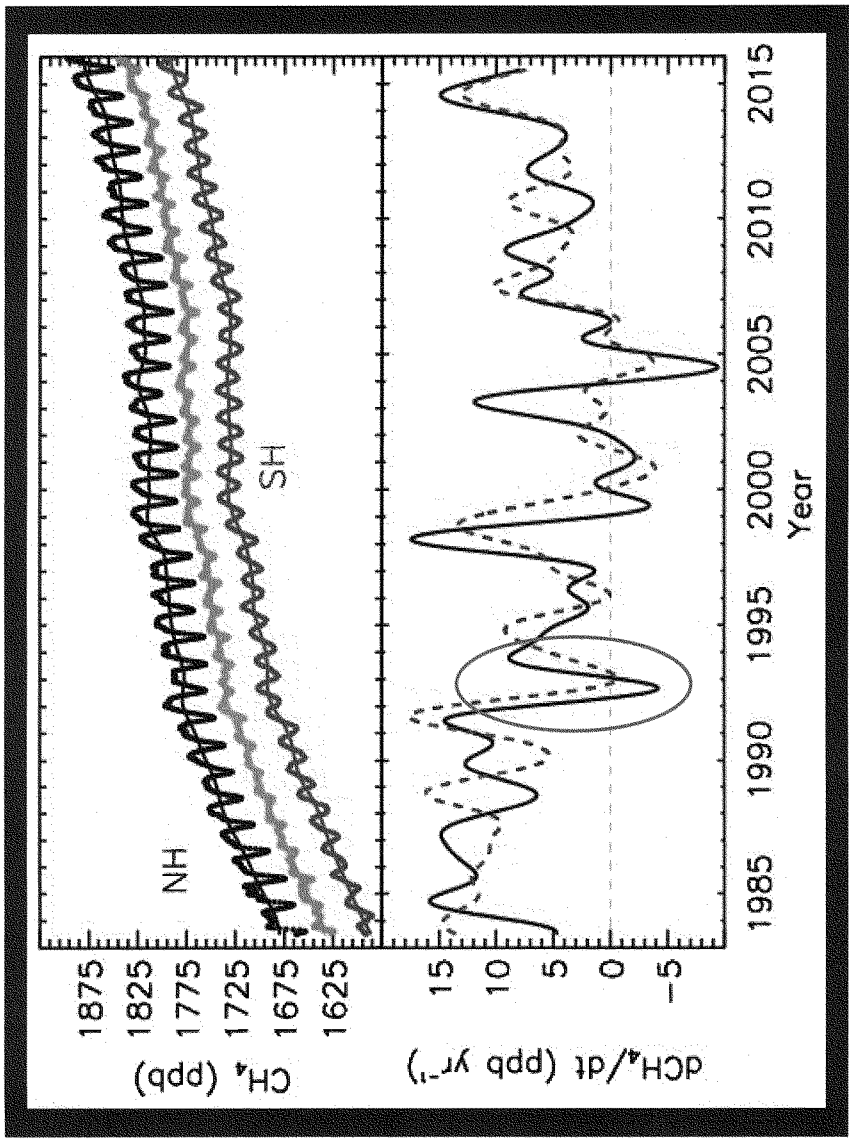

GMD Global Air Sampling Network
90°N
60°N
30°N
0°
30°S
60°S
90°S
100°E 140°E 180° 140°W 100°W 60°W 20°W 20°E 60°E 100°E
*Weekly samples
*Portable sampler
*Analyzed by GC/FID
*www.esrl.noaa.gov/gmd/ccgg/iadv/

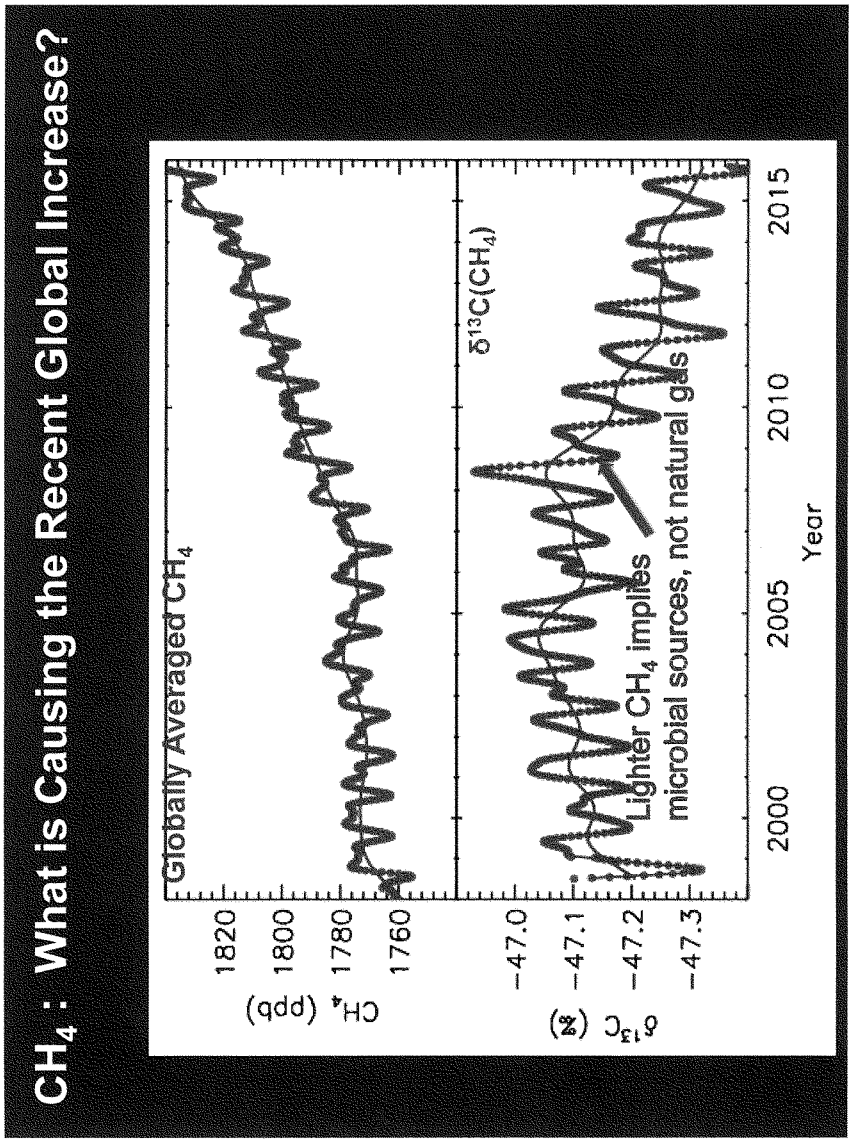
Atmospheric Baseline Observatories



CMDL Measures Carbon Cycle Gases
From Tall Towers and Light Aircraft

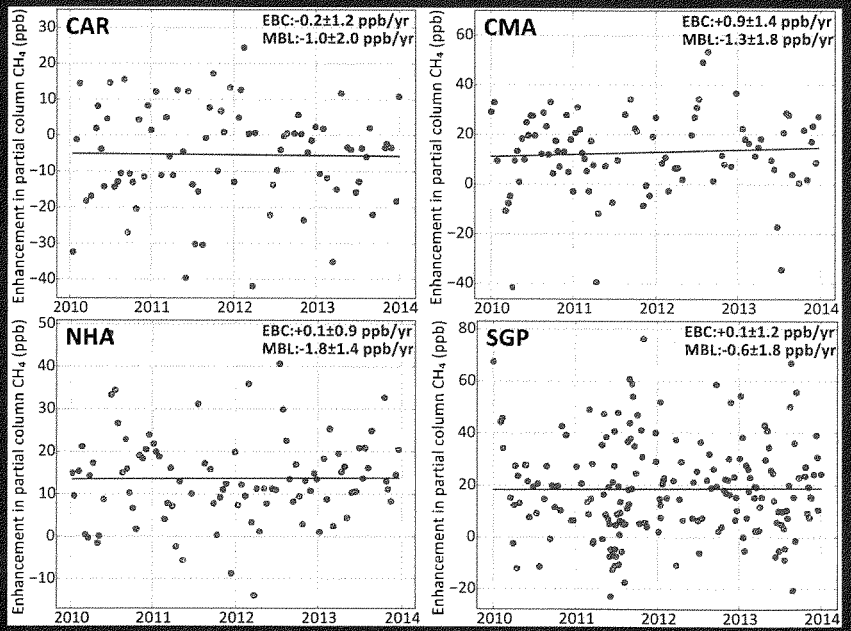



NH
SH
1875
1825
1775
1725
1675
1625
CH4 (ppb)
15
10
5
0
−5
dCH4/dt (ppb yr−1)
1985
1990
1995
2000
2005
2010
2015
Year


CH_4 : What is Causing the Recent Global Increase?
Globally Averaged CH_4
CH_4 (ppb)
1820
1800
1780
1760
$\delta^{13}C(CH_4)$
$\delta^{13}C$ (‰)
−47.0
−47.1
−47.2
−47.3
Lighter CH_4 implies
microbial sources, not natural gas
2000
2005
2010
2015
Year

ESRL Oil/Gas Research – How?
NOAA employs a unique combination of observational platforms, analysis approaches and human expertise.

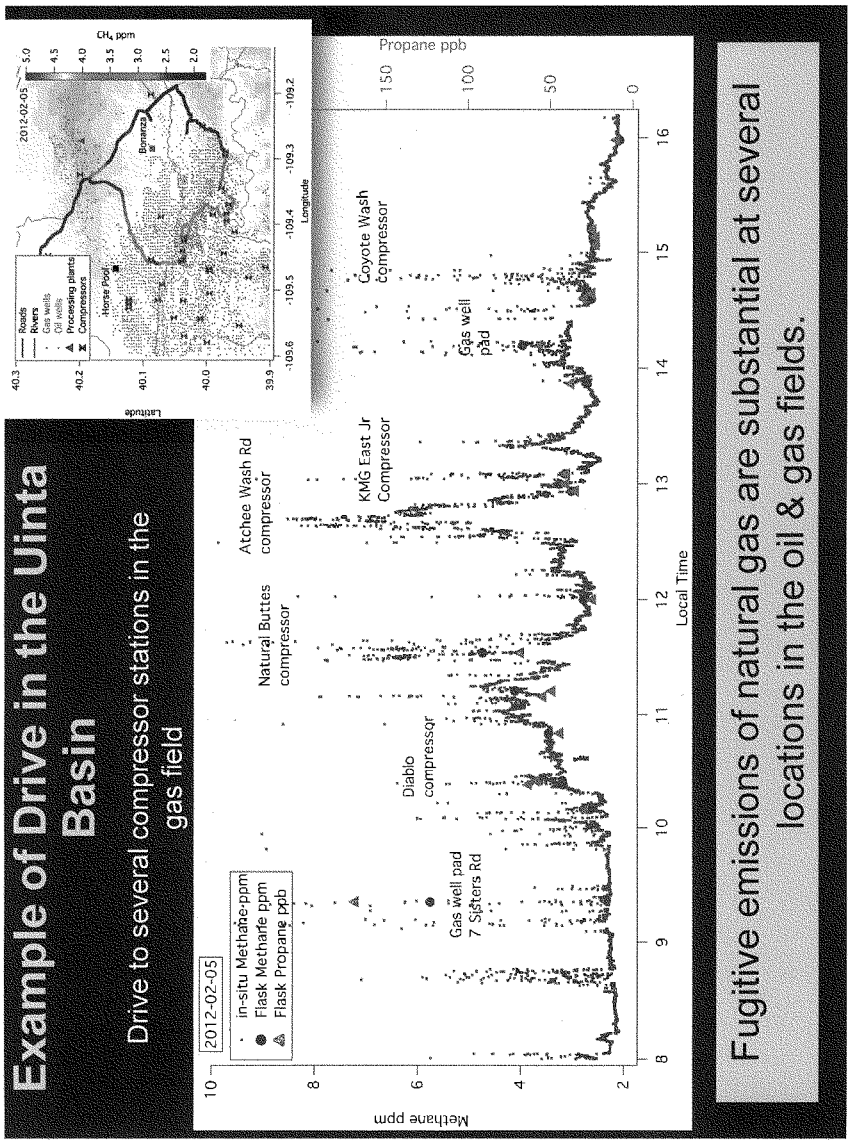
Partial Column Average CH_4 from Aircraft Profiles: No Significant Relative Trends!

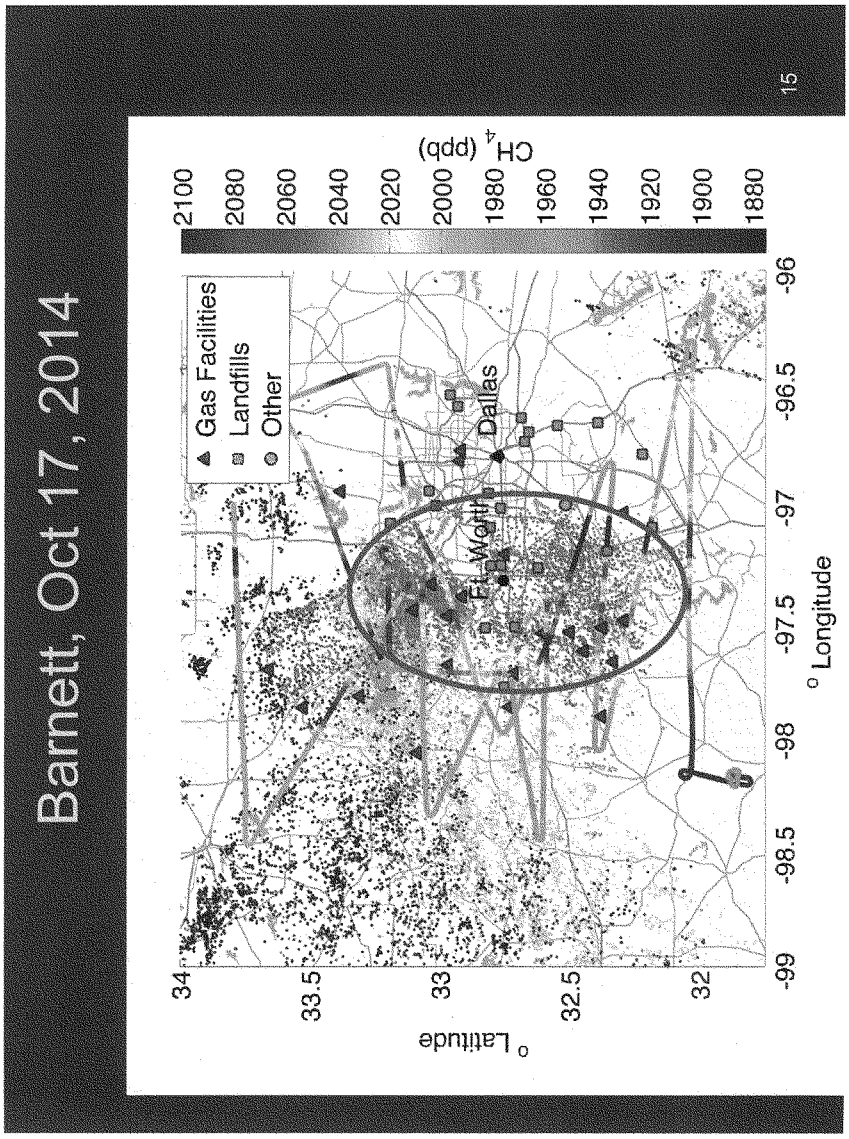


EBC – empirical boundary curtain (interpolated aircraft profiles)
MBL – marine boundary layer surface

Instrumentation:
NOAA Light Aircraft
• In situ CH4 and Ethane: natural gas marker
• In situ CO2 (CO): combustion markers
• In situ NO2: combustion marker, ozone precursors
• In situ O3 (two instruments)
• Discrete air samples: CH4, CO, CO2, C2-C8 alkanes, aromatics
• Daily operations, 2 people on site, 1-2 remotely

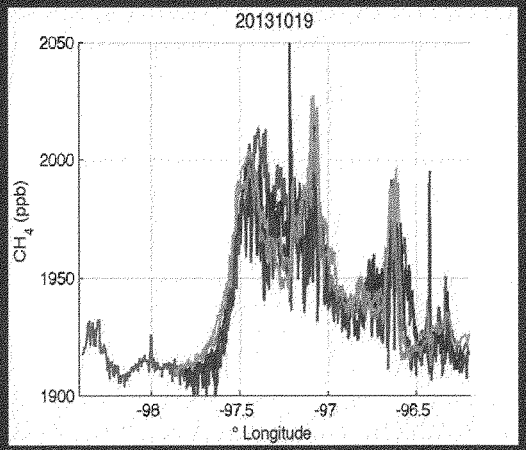
NOAA Mobile Lab
• In situ CH4 and Ethane: natural gas markers
• In situ CO2, CO: combustion markers
• In situ NO/NO2: combustion markers, ozone precursors
• In situ VOCs (aromatics, oxygenates): ozone precursors
• In situ O3 (two instruments)
• Discrete air samples CH4, CO, CO2, C2-C8 alkanes, aromatics
• Daily operations: 2-5 people on site

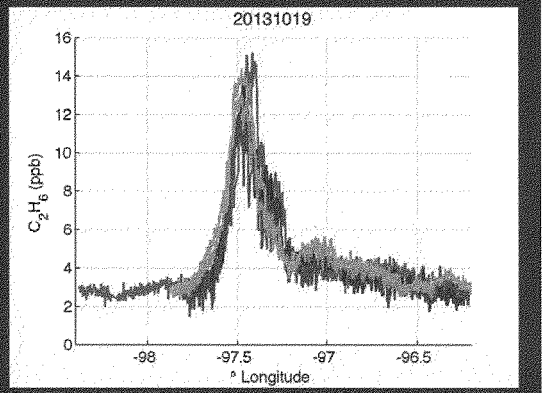

Example of Drive in the Uinta Basin
Drive to several compressor stations in the gas field
2012-02-05
in-situ Methane ppm
Flask Methane ppm
Flask Propane ppb
Methane ppm
Propane ppb
Local Time
Gas well pad 7 Sisters Rd
Diablo compressor
Natural Buttes compressor
Atchee Wash Rd compressor
KMG East Jr Compressor
Coyote Wash compressor
Gas well pad
Roads
Rivers
Gas wells
Oil wells
Processing plants
Compressors
Horse Pool
Bonanza
Latitude
Longitude
CH4 ppm
Fugitive emissions of natural gas are substantial at several locations in the oil & gas fields.


Barnett, Oct 17, 2014
Gas Facilities
Landfills
Other
Ft. Worth
Dallas
CH4 (ppb)
2100
2080
2060
2040
2020
2000
1980
1960
1940
1920
1900
1880
34
33.5
33
32.5
32
-99
-98.5
-98
-97.5
-97
-96.5
-96
° Latitude
° Longitude
15

Barnett, Texas: 19 Oct 2013

5 downwind transects



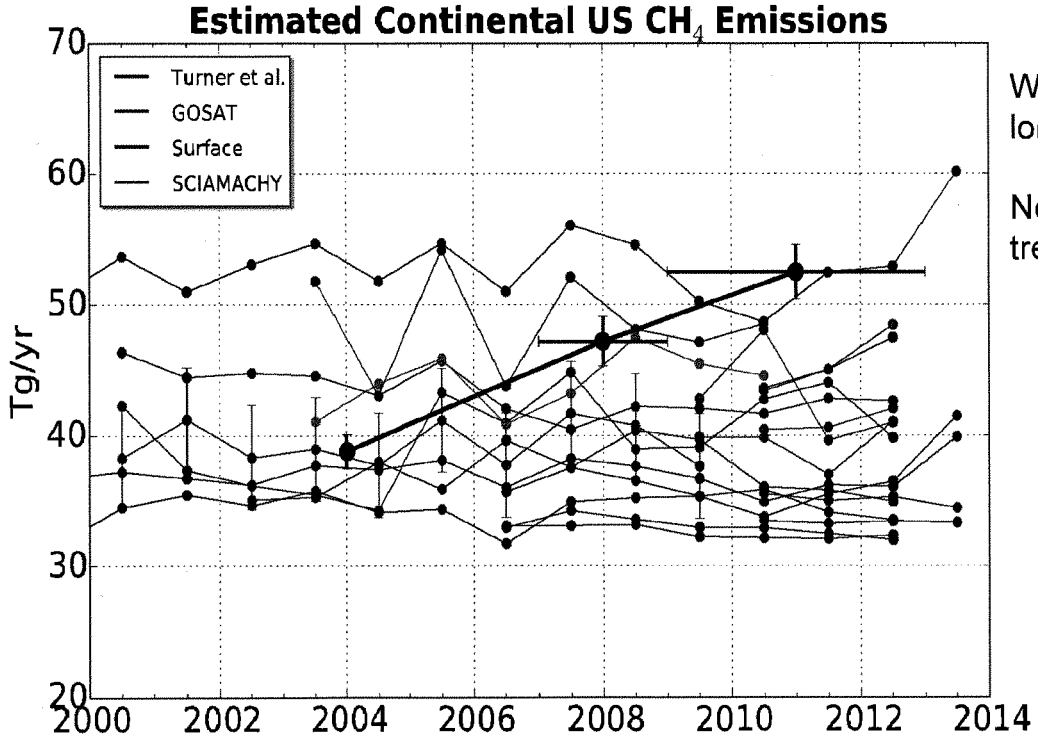


Methane (left) and ethane (right) in five separate downwind transects show consistency of plume. They also indicate that a portion of the methane enhancement does not correspond with an ethane enhancement.

16

Top-down studies: critical to evaluate inventory emission estimates
High & Low Scenarios
Middle Scenario
EPA 2016 GHGI
EPA 2015 GHGI
EPA 2010 GHGI

What Do Time-Dependent Inversions Show?

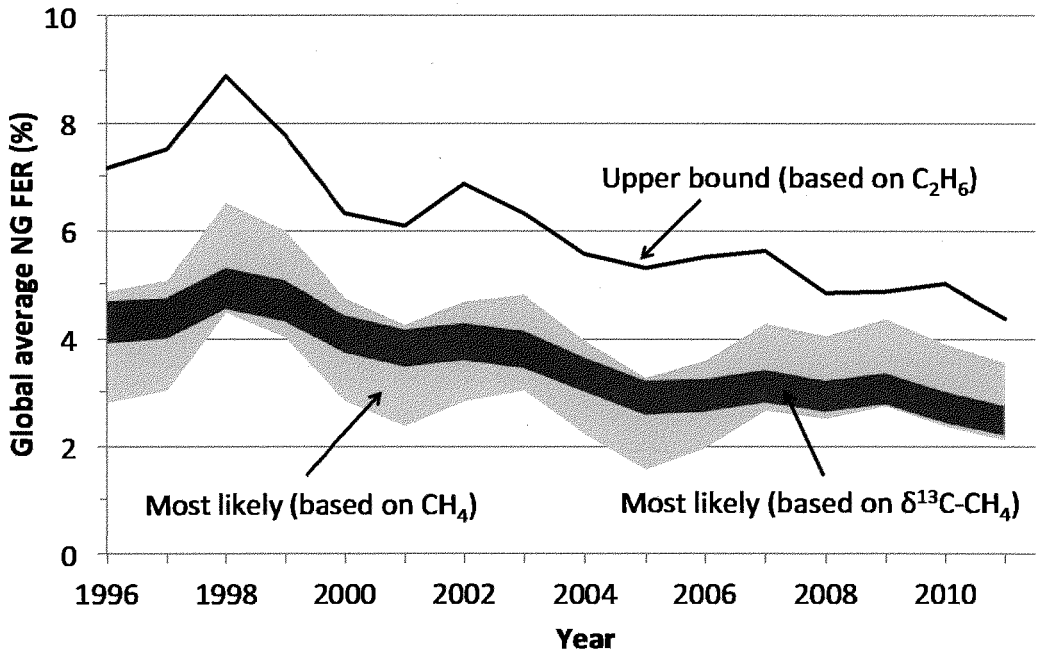


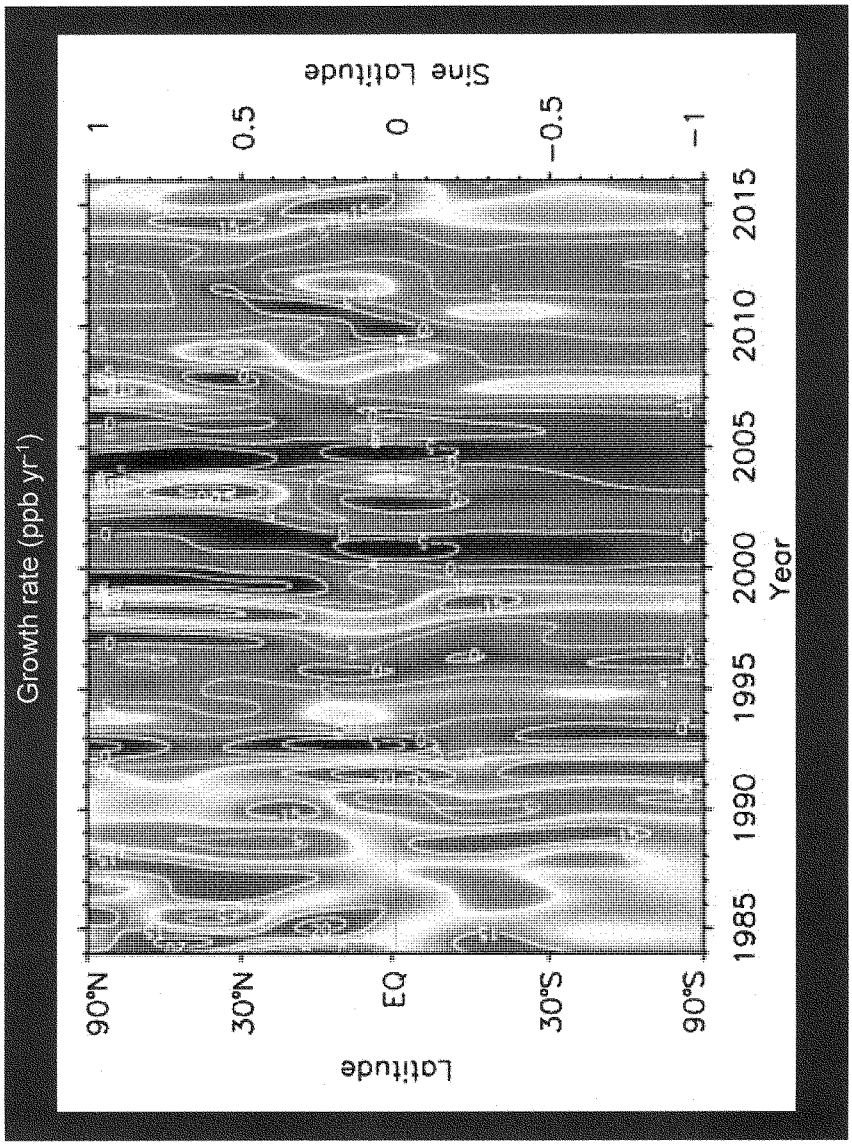
Widely varying long-term means.

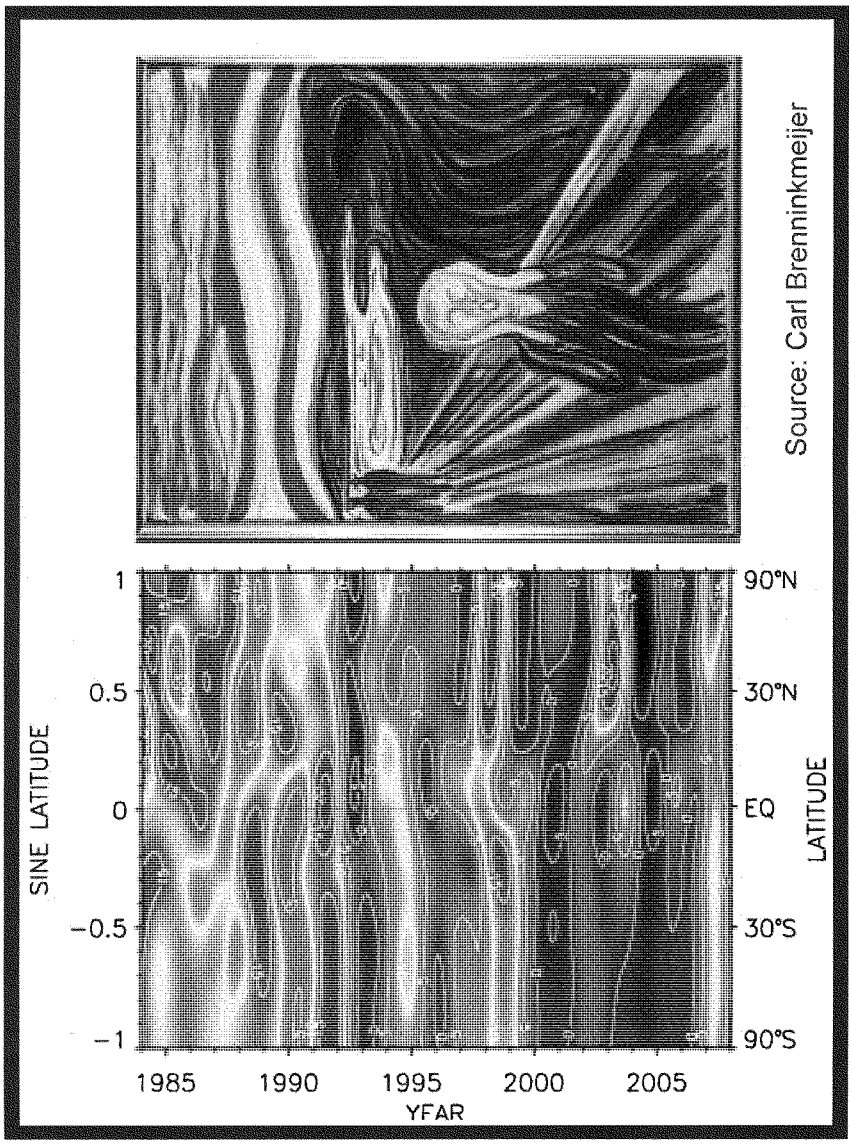
No large upward trends.

O&G efficiency ("leak rate") improving globally over time

Schwietzke et al., 2014 (ES&T)




Growth rate (ppb yr⁻¹)
Latitude
90°N
30°N
EQ
30°S
90°S
1985
1990
1995
2000
2005
2010
2015
Year
Sine Latitude
1
0.5
0
−0.5
−1


Source: Carl Brenninkmeijer
SINE LATITUDE
1
0.5
0
−0.5
−1
90°N
30°N
EQ
30°S
90°S
LATITUDE
1985
1990
1995
2000
2005
YEAR

Conclusions

- In situ observations, atmospheric inversions, and best available bottom-up information do not support a large, recent increase in US CH_4 emissions.
- We have not detected changing US anthropogenic CH_4 emissions from space.
- There is strong evidence that the FF sector is not driving the recent global CH_4 increase.
- Probable cause of the CH_4 increase: Tropical wetlands
- **Policy relevant work needs to be impeccable.**

Natural Gas

Overview

Shell in PA

Workforce & Education

Companies in PA

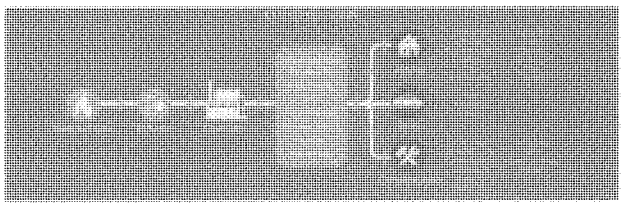
Resources & Funding

Newsletter Signup (https://app.e2ma.net/app2/audience/signup/1817000/1758395/)

Overview

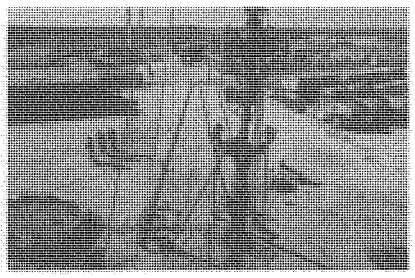
Pennsylvania is the second-largest producer of natural gas in the country - **with production up more than 2,400% between 2005-2014 (http://www.api.org/news-policy-and-issues/news/2016/07/26/pennsylvania-natural-gas-production-up)** - but our natural gas market extends beyond production. Natural gas usage fits into many aspects of our economy, including heat, power, downstream manufacturing, and electricity generation. Other natural gas uses, such as compressed natural gas, offer inexpensive transportation fuel to companies who locate in the state. With Royal Dutch Shell's planned ethylene plant and a local, reliable, and inexpensive source of feedstock, plastics products manufacturing stands to grow exponentially.

PA Natural Gas at a Glance



Commentary: University study backs safety of fracking

Posted by FuelFix.com Date: August 23, 2016



A well is drilled at an Apache Energy site in the Permian Basin in Midland, Texas. (Jim Wilson/The New York Times)

By Erik Milito

American Petroleum Institute

Evidence continues to accumulate that fracking is safe. Earlier this year, the University of Cincinnati completed a three-year study in which researchers examined water samples three to four times per year from 23 wells in the Utica shale region. The study found no evidence linking fracking to groundwater contamination, according to Dr. Amy Townsend-Small, a geologist involved with the study. Samples that were high in methane "clearly did not have a natural gas source," researchers found. In fact, Townsend-Small says, "Some of our highest observed methane concentrations were not near a fracking well at all."

Erik Milito is the director of Upstream and Industry Operations for the American Petroleum Institute.

Good news -- unless you have an anti-energy political agenda. Some of the study's funders apparently do, and they "were a little disappointed in our results," Townsend-Small said. "They feel that fracking is scary, and so they were hoping our data could point to a reason to ban it," she continued.

Oil and natural gas opponents are similarly disappointed with a landmark study EPA released last June. The five-year, $31 million study of hydraulic fracturing "did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States." EPA's exhaustive study is the most complete compilation to date of scientific data on the issue, including more than 950 sources of information, published papers, technical analysis, contributions from stakeholders and peer-reviewed EPA scientific reports.

Since releasing its findings, the EPA has faced calls to walk back its scientific conclusions. While offering no evidence to contradict EPA's findings, some members of its Science Advisory Board recently called on the agency to provide additional data.

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But the science is clear, and the evidence – including 65 years of safe operation – is overwhelming. No cases of drinking water contamination have been documented in the Marcellus, Utica, Barnett, Permian, Eagle Ford, Woodford, Fayetteville, Haynesville, Bakken, Denver- Julesburg, Piceance, Raton, or any other shale plays where hydraulic fracturing has been used. The combination of continually improving industry practices, advancing state programs and federal environmental statutes all work together to provide an effective structure that allows for the essential development of the nation's oil and natural gas resources while protecting the environment.

The United States remains the world's leading oil and natural gas producer, and we couldn't have done it without hydraulic fracturing, which accounts for more than 43 percent of domestic oil production and 67 percent of natural gas production.

The U.S. also leads the world in reduction of greenhouse gas emissions, and fracking is the primary force behind that achievement, too. Energy-related carbon dioxide emissions dropped 12 percent below 2005 levels last year, the Energy Information Administration (EIA) reports, "mostly because of changes in the electric power sector" – specifically, "increased use of natural gas for electricity generation." Energy-related carbon emissions for this year are projected to reach their lowest levels since 1992. However much leave-it-in-the-ground activists may wish to deny it, we wouldn't have such an abundance of clean-burning, affordable natural gas to use in power generation, and resulting emissions declines, without fracking.

The idea that energy production and climate progress are mutually exclusive just doesn't hold up. According to Environmental Protection Agency (EPA) data, aggregate national emissions of six common air pollutants have fallen an average of 63 percent since 1980 – while our population, energy use and GDP have increased. We're even one-third of the way toward achieving the emissions reductions we committed to under the Paris climate agreement.

The role hydraulic fracturing plays in cutting carbon emissions has become clear only recently, but the environmental advantages of the technology as a production method have been understood for years. A 1999 Department of Energy report credits the combination of hydraulic fracturing and horizontal drilling with providing "environmental benefits" because "less wells are drilled, there is a smaller footprint, recovery is optimized, there is less produced water, less drilling waste, and – for hydraulic fracturing – protection of groundwater resources." And technology has only advanced since then.

The facts on fracking show that not only has the technology helped lower fuel, utility and manufacturing costs, and not only is it environmentally safe, but it is integral to U.S. status as the world's leading reducer of greenhouse gas emissions.

About The Author

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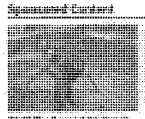

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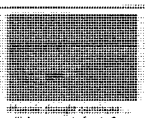

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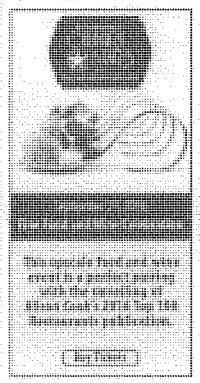

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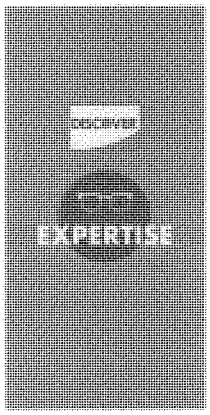

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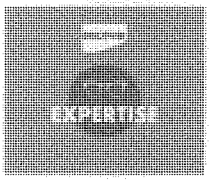


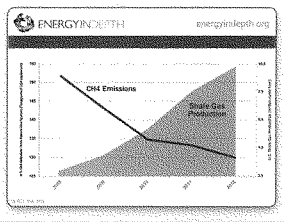
FACT SHEET:

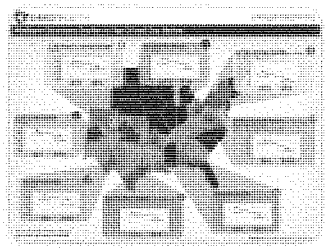
Methane Emissions and Hydraulic Fracturing: Top Five Facts

With the White House's announcement today on new methane regulations, here are the top five facts you may not know.

1 Methane emissions have fallen dramatically as natural gas production has skyrocketed.
As the Wall Street Journal recently explained, President Obama's plan to impose new regulations on U.S. oil and natural gas production is "willfully ignoring the plunge in U.S. methane." The WSJ also noted this decrease happened in the "same years when the U.S. became the world's natural-gas leader, with production increasing by nearly fourfold since 2008."

2 EPA consistently finds methane emissions are declining.
The Environmental Protection Agency (EPA) recently released its Greenhouse Gas Reporting Program data, which showed that methane emissions from hydraulic fracturing fell by an amazing 73 percent. A few months earlier, EPA also published its Greenhouse Gas Inventory, which showed that methane emissions from natural gas systems fell 16.9 percent since 1990, with field production emissions falling more than 40 percent since 2006. As U.S. Energy Department Secretary Ernest Moniz said, "More than half I believe now of the current frack jobs are so-called green completions, where the methane is captured and is for economic benefit."

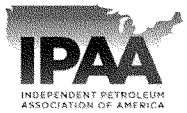




3 Methane emissions are declining in major oil and gas basins across the U.S.
EPA data show that methane emissions from oil and natural gas development have significantly declined in many of the top producing basins across the country, even as oil and gas production has skyrocketed.

4 Research shows climate benefits of natural gas are not erased by emissions.
A study published late last year by researchers at the University of Texas and the Environmental Defense Fund (EDF) finds that methane emissions from the upstream portion of the supply chain are only 0.38 percent of production. That's about 10 percent lower than what the same research team found in a study released in September 2013. Studies by the National Renewable Energy Laboratory, U.N. IPCC, Massachusetts Institute of Technology, and many others have also found that methane emissions are low and natural gas has clear climate benefits. As EPA administrator Gina McCarthy recently said, "Responsible development of natural gas is an important part of our work to curb climate change."

5 Industry's 'voluntary reductions' led to dramatic decline in methane emissions.
As the EPA explains: *"The decrease in production emissions is due to increased voluntary reductions,* from activities such as replacing high bleed pneumatic devices, regulatory reductions, and the increased use of plunger lifts for liquids unloading." In its press release today announcing the regulations, the White House also pointed out that "Voluntary efforts to reduce emissions in a comprehensive and transparent manner hold the potential to realize significant reductions in a quick, flexible, cost-effective way. Achieving significant methane reductions from these voluntary industry programs and state actions could reduce the need for future regulations. The Administration stands ready to collaborate with these and other voluntary efforts, including in the development of a regime for monitoring, reporting and verification."



April 22, 2016

via e-filing at www.regulations.gov

US Department of the Interior
Bureau of Land Management
Mail Stop 2134 LM
1849 C St., NW
Washington, DC 20240

Re: RIN 1004-AE14: Waste Prevention, Production Subject to Royalties, and Resource Conservation, proposed rule published in the Federal Register on February 8, 2016 (81 Fed. Reg. 6616)

To Whom It May Concern:

I. INTRODUCTION

The Independent Petroleum Association of America ("IPAA"), the Western Energy Alliance ("Alliance"), the American Exploration and Production Council ("AXPC"), and the US Oil and Gas Association ("USOGA") (collectively "the Associations") submit the following comments on the Bureau of Land Management's (BLM) proposed Waste Prevention, Production Subject to Royalties, and Resource Conservation Rule ("Proposed Rule").

The Associations

The Independent Petroleum Association of America represents the thousands of independent oil and natural gas exploration and production companies, as well as the service and

supply industries that support their efforts.. Independent producers drill about 95 percent of American oil and natural gas wells, produce about 54 percent of American oil, and more than 85 percent of American natural gas.

Western Energy Alliance represents over 450 members involved in all aspects of environmentally responsible exploration and production of oil and natural gas in the West. The Alliance represents independent oil and gas producers, the majority of which are small businesses with an average of fifteen employees.

The American Exploration & Production Council is a national trade association representing 28 of America's largest and most active independent natural gas and crude oil exploration and production companies. AXPC's members are "independent" in that their operations are limited to the exploration for and production of natural gas and crude oil. Moreover, its members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC's members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce crude oil and natural gas, and that allow our nation to add reasonably priced domestic energy reserves in environmentally responsible ways.

The US Oil & Gas Association was founded almost one hundred years ago and is the oldest national trade association for oil and natural gas producers. The Association's Division in Washington, D.C., is the umbrella for its Divisions in Texas, Louisiana, Oklahoma and Mississippi/Alabama. With nearly 5,000 Members, USOGA represents the full spectrum of the domestic petroleum industry; it provides a forum for the discussion and advocacy of mutually beneficial domestic exploration and production policies for all members regardless of size.

The member companies of the Associations have valid existing and producing oil and gas leases on federal and Indian lands, and plans that include future leasing, exploration and production activities on federal and Indian lands. Consequently, the companies will be directly affected by the many requirements that the Proposed Rule seeks to impose.

The Associations have made significant progress in addressing the issues of venting, flaring, and methane emissions from their oil and gas operations, and will continue to do so. However, after careful examination, we have concluded that the Proposed Rule, which addresses those issues, is arbitrary and in excess of BLM's legal authority and should not be promulgated. Among other things, the Proposed Rule is in direct conflict with the written approvals that BLM has given to hundreds of operators to vent and flare. It is also focused in many respects on reducing methane emissions, which BLM lacks authority to do, rather than on preventing the "waste" of gas.

At a minimum, we urge BLM to suspend its rulemaking efforts until the Environmental Protection Agency (EPA) has finished the work it has recently begun on regulations governing the emissions of air pollutants from existing oil and gas sources. In accordance with BLM's own policy, that would insure that the regulated community is not subjected to conflicting or redundant federal mandates. Instead, BLM should redirect its resources towards processing applications for the pipeline rights-of-way across federal and Indian lands that are essential for the building of gas capture technology. Timely processing of such applications would have a much greater and more immediate impact on reducing flaring levels than BLM's proposed one-size-fits-all, command-and-control regulation.

Should BLM choose to proceed with the Proposed Rule despite its lack of authority, the Associations urge BLM to make numerous revisions to the Proposed Rule which, in its current form, is unworkable for the oil and natural gas industry as well as BLM. We have provided numerous detailed suggestions on how to make the Proposed Rule workable in this letter. We look forward to working with BLM to reduce any "waste" of gas that may be occurring due to venting and flaring from the operations of our member companies on federal and Indian lands.

II. GENERAL LEGAL AND POLICY CONCERNS

A. Work on the Proposed Rule should be suspended pending the completion of EPA's "existing sources" rule

A primary focus of BLM's Proposed Rule is to reduce venting and flaring from existing oil and gas operations.[1] However, on March 10, 2016, the White House announced that EPA, as part of the President's climate change agenda, will immediately begin developing regulations that will regulate methane emissions from existing oil and gas operations. In view of this announcement, BLM should suspend further development of the Proposed Rule until it can insure that the requirements of the Proposed Rule, when considered together with the regulations for existing oil and gas operations that EPA is now developing, will not subject operators to "conflicting or duplicative Federal mandates." [2] It would be a significant waste of the time and resources of both BLM and the regulated community to continue to work on the development of the Proposed Rule without knowing what EPA will soon propose in its regulations for existing oil and gas operations. Moreover, as explained below, BLM lacks the authority to directly regulate the emission of methane and should not be engaged in any such effort under any circumstances.

B. The Proposed Rule is arbitrary and should not be promulgated

Under the Administrative Procedure Act, a court may set aside agency actions that are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."[3] The Supreme Court has stated that an agency rule is arbitrary if "the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem," or failed to "articulate a satisfactory explanation for its action, 'including a rational connection between the facts found and the choice made.'" [4] It has also stated that a rule that is intended to replace an existing policy is arbitrary if the agency "disregards [the] facts and

[1] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 6616, 6627 (Feb. 8, 2016).
[2] *Id.*
[3] 5 U.S.C. § 706(2)(A).
[4] Motor Vehicle Mfrs. Ass'n v. State Farm Ins., 463 U.S. 29, 43 (1983).

circumstances that ... were engendered by [its] prior policy."[5] As explained below, BLM has violated these well-established standards in developing the Proposed Rule. The Proposed Rule is therefore arbitrary and should not be promulgated.[6]

1. BLM may not justify its waste prevention measures by reference to the reductions in methane emissions that they might achieve

One of the primary goals of the Proposed Rule is to reduce the amount of methane emissions from oil and gas operations. In fact, the way the Proposed Rule is promoted, this appears to be the primary goal of the Proposed Rule. The Proposed Rule is cited as one of the principal methane reduction actions under the President's *Climate Action Plan: Strategy to Reduce Methane Emissions.*[7] In addition, BLM has repeatedly emphasized the methane reductions the Proposed Rule would achieve as a justification for its provisions. Most recently, in announcing the extension of the comment period on the Proposed Rule, BLM referred to the Proposed Rule as the "Proposed Rule to Reduce Methane Emissions, Wasted Gas on Public Lands," and as the "Methane and Waste Prevention Rule," and touted the fact that the "proposal is consistent with the Obama Administration's goal to cut methane emissions from the oil and gas sector by 40-45 percent from 2012 levels by 2025." As explained below, BLM lacks authority to require the oil and gas industry to reduce such emissions, except as those reductions may occur as an incident of an otherwise lawful measure to prevent the "waste" of gas adopted pursuant to BLM's authority under the Mineral Leasing Act ("MLA").

BLM is proposing to adopt the waste prevention measures in the Proposed Rule based on the authority granted to it by section 225 of the MLA.[8] That section provides that federal oil and gas lessees, as a condition of their leases, must "use all reasonable precautions to prevent waste

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[5] FCC v. Fox TV Stations, Inc., 556 U.S. 502, 516 (2009).

[6] The Proposed Rule is unclear in its applicability with respect to instances of mixed ownership. We seek clarification from BLM on whether operators drilling from a location on state or fee surface ownership that enter or pass through federal minerals will be subject to the Proposed Rule. We contend that these locations should be exempt from compliance with the Proposed Rule. Should BLM apply the Proposed Rule to these locations, it would need to revise its cost-benefit analysis to reflect that decision, as that would add significant costs for operators.

[7] WHITE HOUSE, CLIMATE ACTION PLAN: STRATEGY TO REDUCE METHANE EMISSIONS (2014), https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf

[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.

of oil and gas developed in the land." [9] The Proposed Rule purports to be an attempt to clarify what constitutes a "reasonable precaution" against "waste."

For purposes of the MLA, it is well established that gas is "wasted" only if it could have been economically captured and marketed or put to beneficial use on the lease, but is not. Thus, to establish that a proposed waste prevention measure is a "reasonable precaution" against "waste," and authorized under the MLA, BLM must demonstrate that the gas that is subject to the measure can be economically captured by the operator. If the gas cannot be economically captured, then it is not being "wasted," and BLM has no authority to otherwise regulate what is being done with it, no matter how much methane it may contain.

Even taking BLM's cost-benefit analysis of the Proposed Rule at face value,[10] it is clear that BLM cannot make the required demonstration with respect to several of its proposed waste prevention measures. For example, BLM estimates that its requirement to replace certain pneumatic pumps with zero-emission pumps would impose costs of $2.7 million per year, but would result in only $2.2 million in savings. Thus, the requirement has a negative cost-benefit ratio, or, in other words, BLM cannot demonstrate that the gas that is currently be vented from the pumps subject to the Proposed Rule can be economically captured by replacing the pumps with zero-emission pumps. Even assuming the validity of BLM's analysis, the only way BLM can justify the measure on a cost-benefit basis is by adding in the $18 million in "monetized benefits" that it believes can be achieved in terms of climate change by the reduction in methane emissions that would occur if zero-emission pumps were used.

However, BLM lacks authority under the MLA to justify its waste prevention measures by adding in the supposed climate change benefits that might be realized by society generally from the incidental reduction in methane emissions that would occur if the measures are implemented. Neither the MLA, nor any of the other statutes that BLM cites in the Proposed Rule's preamble, gives BLM the authority to regulate the emission of gas from oil and gas

[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.
[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.

operations out of a concern about the effect those emissions may have on climate change. That authority, to the extent it exists, has been given by Congress exclusively to EPA under the Clean Air Act. By relying on the benefits of methane reduction to justify its waste prevention measures, BLM is clearly "rel[ying] on factors which Congress [did] not intend it to consider" when developing such measures under the MLA, and is therefore acting arbitrarily and in violation of law.

To demonstrate that a particular measure is a "reasonable precaution" against "waste," BLM must demonstrate that the gas subject to the measure can be economically captured by the operator. Whatever benefits calculated using the social cost of methane might be realized as a result of the measure have no place in that demonstration. The benefits that may flow to society generally are irrelevant to the question of whether the gas can be economically captured by the operator. Put simply, because those benefits do not flow to the operator, they are not benefits that can be spent to capture the gas. Thus, while an otherwise "reasonable" measure to prevent the "waste" of gas may have the incidental effect of reducing the amount of methane that is emitted from oil and gas operations, such a measure may not be made "reasonable" for purposes of the MLA by virtue of that incidental effect.

Federal oil and gas lessees have a right to develop the oil and gas resources on their leases, subject to the requirement that they take "reasonable precautions" to prevent the "waste" of those resources, and that they comply with other applicable federal laws and regulations, like the ones adopted by EPA to regulate air emissions. If they are not "wasting" those resources—i.e., if those resources cannot be economically captured—BLM is not free to impose so-called waste prevention measures on them pursuant to its MLA authority just because society as a whole may benefit from the incidental methane reductions that would occur if the measures were implemented. The oil and natural gas industry has and will continue to work voluntarily to address methane emissions, but federal oil and gas lessees may not be made to bear the costs of reducing those emissions under the guise of BLM's authority to impose "reasonable precautions" to prevent the "waste" of gas.

BLM seems to suggest (without explanation) that its obligation under the Federal Land Policy and Management Act ("FLPMA") to manage public lands under the principle of multiple use, which is defined as "management in a 'harmonious and coordinated' manner 'without permanent impairment to the quality of the environment,'" may provide it with the authority to regulate methane emissions.[11] But that general reference to the "permanent impairment of the environment," which is found only in the definition section of FLPMA, cannot be read as a substantive grant of authority to BLM to set its own methane emission standards, or to limit methane emissions out of a concern for the effect they may have on climate change. There is nothing in the substantive provisions of FLPMA that would support such a reading, or that would give BLM any parameters to observe in exercising such an authority. Especially in light of the detailed and complex provisions for that Congress has established for the regulation of air quality in the Clean Air Act, it is unreasonable to suppose that Congress would give BLM the authority to regulate air quality completely untethered to any substantive guidance from it as to how to exercise that authority. At most, the provision in FLPMA can be read as requiring BLM to insure that activities conducted on federal lands comply with all applicable environmental standards, as established by the agencies with express and substantive authority from Congress to do so.

BLM further confirms the air quality focus of the Proposed Rule when it notes that:

> This waste of gas through flaring can affect the quality of life for nearby residents, who note that flares are noisy and unsightly at night. Venting, flaring, and leaks of gas also contribute to local, regional, and global air pollution. Volatile Organic Compounds (VOCs) and hazardous air pollutants (components of the gas, such as benzene, toluene, ethylbenzene, and xylene) are released into the atmosphere when natural gas is released through venting, flaring, or incomplete combustion at a flare. VOCs combine with sunlight and Nitrogen Oxides (NO_X), which are created by burning fossil fuels, to form ground-level ozone, or smog, which causes a wide range of health effects. Benzene and other components of natural gas are also classified as hazardous air pollutants, which are

[11] 81 Fed. Reg. 6629.

> known or suspected to cause cancer or reproductive effects. Flaring of gas produces NO_X and particulate matter, both of which can cause respiratory and heart problems.[12]

However, as explained above, BLM lacks the authority to regulate such emissions for the sake of air quality.

Moreover, even if BLM somehow had authority to require federal oil and gas lessees to reduce methane emissions out of a concern for the effect they might have on climate change, BLM would still have to provide a reasonable justification for doing so, which it has not. Indeed, it is extremely unlikely that the Proposed Rule will have any meaningful impact on global greenhouse gas (GHG) emissions. Global methane emissions are estimated at 6,875 million metric tons CO_2-eq per year, whereas U.S. methane emissions are about 708 million metric tons per year, or about 10.2% of global emissions. BLM estimates that the Proposed Rule will reduce between 4.1 and 4.2 million metric tons of CO_2-eq per year.[13] Taking BLM's 4.2 MMT CO_2-eq per year, the Proposed Rule provides a reduction of 0.061% of global methane emissions. More importantly, methane emissions make up only a small portion of total global GHG emissions. EPA estimates put annual global greenhouse gas emissions at approximately 45,863 million metric tons of CO_2-equivalent (CO_2-eq) in 2010.[14] By BLM's most ambitious estimates, which are likely overstated, its Proposed Rule will reduce greenhouse gas emissions by 4.2 million metric tons of CO_2-eq. That's approximately 0.0092% of global greenhouse gas emissions.

While BLM asserts that "[v]enting and leaks of natural gas in the oil and gas production process also contribute to climate change,"[15] the empirical evidence on this record contradicts BLM's assertion. BLM's proposal is devoid of any discussion or evidence demonstrating how significantly less than a 1% reduction in domestic methane emissions will have any impact on climate change. The APA demands far more than regulation via the precautionary principle. See e.g., Washington Environmental Council v. Bellon, 732 F.3d 1131, 1145 (9th Cir. 2013) (striking

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[12] 81 Fed. Reg. 6627

[13] *Fact Sheet on Methane and Waste Reduction Rule*. Bureau of Land Management. January 2016.

[14] U.S. EPA, Climate Change Indicators in the United States, https://www3.epa.gov/climatechange/science/indicators/ghg/global-ghg-emissions.html (last visited Apr. 6, 2016)

[15] *Id.* at 6627.

down Plaintiff's arguments that "any and all contribution of greenhouse gases must be curbed," and noting the common-sense notion that, as articulated in Massachusetts v. EPA, regulatory action should focus on reducing "meaningful contributions" of GHGs).

On a global scale, the purported impact of the Proposed Rule is far from "significant." It is hard to imagine anywhere else where a 0.0092% reduction of anything would be considered significant, particularly given that climate change is a global phenomenon, generally measured on the basis of country-by-country or even continent-by-continent contribution. By justifying the Proposed Rule by reference to climate change benefits and contributions towards mitigating climate change impacts, the Proposed Rule proposal falls far short of the rational basis that the APA requires to support a rulemaking. Simply put, BLM does not make even a slightly credible case that the Proposed Rule will have any impact on climate change.

The Proposed Rule also ignores the reality on the ground in the oil and natural gas production industry. To date, industry has achieved remarkable emission reductions without duplicative and burdensome federal regulations. Methane emissions from oil and natural gas exploration and production (E&P) are 1.07 percent of total U.S. GHG emissions[16] and the natural gas sector alone has reduced methane emissions by 38 percent since 2005. *See EPA, 2014 GHG Reporting Data* (2014). In 2013, "reported methane emissions from petroleum and natural gas systems sector" decreased by 12 percent from 2011, and the largest reduction came from

[16] EPA has announced modification of the petroleum and natural gas systems methane emissions estimates in the GHG Inventory. EPA asserts that this change reflects new data. Two changes affecting the exploration and production component are at issue. The first involves estimating emissions from gathering and boosting activities that have not been reported under the GHG Inventory which EPA is arbitrarily assigning to production. The second involves methane reported under Subpart W suggesting that some exploration and production emissions are higher than previous estimates. Much of EPA's rationale for increasing the GHG Inventory for these emissions hinges on scaling up the Subpart W reported emissions to reflect the entire industry. EPA indicates that only 30 percent of exploration and production facilities report under Subpart W. However, EPA's efforts to scale up emissions appear to rely too heavily on the facility number rather than its nature. Clearly, the non-reporting facilities would overwhelmingly be marginal oil and natural gas wells. Marginal wells would have a very different and lower emissions profile than the larger facilities reporting under Subpart W. Even EPA initially recognized this distinction when it selected the facility size for reporting under Subpart W. It chose the threshold that yields the 30 percent of facilities reporting because EPA concluded that these facilities accounted for 85 percent of emissions. Consequently, EPA's actions to alter the GHG Inventory need to be thoroughly vetted before they are accepted. If they are found to be accurate, these changes increase the "production" segment of the petroleum and natural gas systems share of GHG emissions to 2.45 percent of the total GHG Inventory or 1.83 percent if the historical definition of exploration and production were used. However, these changes would not be an actual increase in emissions but an alteration of the entire baseline for the Inventory.

hydraulically fractured natural gas wells (resulting in a decrease of 73 percent in emissions). *Id.* According to a study by the University of Texas, Austin, methane emitted from all upstream source categories at natural gas production sites represents just 0.42 percent of gross natural gas production volumes.[17] On a national scale, despite significant growth in production in this sector over the past several years, methane and other emissions have continued to decline.

Technological and operational improvements in this sector continue to advance at remarkable rates and the emissions profile for new and modified facilities is declining and will only continue to do so, particularly as operators move towards centralized gathering systems and tankless or pressurized tank facilities. For example, in Colorado, recent emissions inventories for the oil and gas sector demonstrate significant *decreases* (*i.e.*, more than 60 percent through 2017) in VOCs despite a growth in production. *See Overview of 2011 and 2017 VOC and NOx Emission Inventories*, Colorado Regional Air Quality Council, at 7 (November 19, 2015). These decreases are due to advances in technology, facility design, better emissions controls, and the inherent incentive to capture and sell as much methane as possible. New facilities in combination with growing infrastructure and voluntary and state-led emission control efforts are already resulting in decreases in sector emissions. Unlike virtually every other industrial sector, production in upstream E&P sources declines over time bringing with it declining emissions (of both VOCs and methane). The Proposed Rule ignores these fundamental realities. Until these contradictions can be satisfactorily explained, any decision to regulate in the face of such overwhelming data would be arbitrary.

In fact, by making natural gas development more expensive and time consuming, the result will be less American natural gas production than without the Proposed Rule, which is directly at odds with the President's overall climate goals. Specifically, since increased natural gas electricity generation is the primary reason that the United States has reduced GHG emissions, as recognized by the International Energy Agency, the Energy Information Administration, and EPA's data, the Proposed Rule is actually counterproductive to efforts to

[17] David T. Allen et al., *Measurements of Methane Emissions at Natural Gas Production Sites in the United* States, 110 Proc. of the Nat'l Acad. of Sci. of the U.S. 18023 (2013).

address climate change.[18] By focusing on the small picture, BLM is losing sight of the bigger picture.

2. BLM's prohibitions on venting and flaring by operators with NTL-4A approvals are arbitrary

Another primary goal of the Proposed Rule is to reduce the amount of associated gas that is being routinely vented or flared from development oil wells. Under current BLM policy, which is set forth in NTL-4A, such venting and flaring is generally prohibited and may only take place with BLM's written approval. To obtain that approval, an "operator [must] demonstrate to the satisfaction of" BLM, based on "an evaluation report supported by engineering, geologic, and economic data, "that the expenditures necessary to market or beneficially use such gas are not economically justified and that conservation of the gas, if required, would lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered if the venting or flaring were permitted to continue." Hundreds of operators have made the demonstration required by NTL-4A to BLM's satisfaction and are currently venting or flaring with BLM's written approval.

BLM is now proposing, however, to do two things in section 3179.6 of the Proposed Rule that are in direct conflict with those approvals. First, it is proposing to prohibit all routine venting of gas, subject to certain narrow exceptions. In other words, it is proposing to find, as a matter of law, that routine venting, regardless of the circumstances of the operator and any approval that has been given to it by BLM under NTL-4A, is a "waste" of gas. Second, it is proposing to limit all routine flaring of gas, subject to certain narrow exceptions, to 1,800 Mcf/month per well. In other words, it is proposing to find, as a matter of law, that "very high rates of flaring from a lease—that is, rates above the proposed 1,800 Mcf/month limit—constitute unreasonable waste under the MLA," regardless of the circumstances of the operator and any approval that has been given to it by BLM under NTL-4A.[19] BLM is proposing to say, in effect, to all operators who currently have BLM's express approval to vent under NTL-4A

[18] U.S. Int'l Energy Agency, World Energy Outlook, (2011) http://www.iea.org/Textbase/npsum/weo2011sum.pdf.; See Figure 12 at U.S. Energy Information Admin., U.S. Energy-Related Carbon Dioxide Emissions, http://www.eia.gov/environment/emissions/carbon/ (last visited Apr. 6, 2016).
[19] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. at 6639.

(based on BLM's case-by-case examination of their particular circumstances) that they may no longer vent, and to all operators who have BLM's approval under NTL-4A to flare amounts of gas in excess of 1,800 Mcf/month per well (based on BLM's examination of their particular circumstances) that they may no longer do so. And BLM is proposing these new prohibitions, which may lead to the shutting-in of wells, without any explanation as to why the venting and flaring it approved should now be prohibited.

In making its proposal to replace NTL-4A with the Proposed Rule, BLM is "disregarding [the] facts and circumstances that ... were engendered by [its] prior policy"—i.e., the well-specific determinations that it made under NTL-4A that current levels of routine venting and flaring of associated gas from particular oil wells is not a "waste" of gas—and is proposing to simply declare by fiat that what it once considered not "wasteful" it now considers "wasteful." By failing to explain on a case-by-case basis why its existing approvals should be revoked, BLM has "entirely failed to consider an important aspect of the problem" that it claims it is trying to address. Thus, the proposed prohibitions on venting and flaring in section 3179.6 are arbitrary as applied to operators who are currently venting and flaring with BLM's approval. Unless and until BLM can explain, on a case-by-case basis, why its previous approvals, on which operators have reasonably relied, are in error, it may not simply set those determinations aside and impose new prohibitions on the operators. Consistent with its obligation not to act arbitrarily, BLM cannot say one day to an operator that a particular practice, as a matter of fact, is not "waste," and then say to that same operator the next day that that same practice, as a matter of law, is "waste."

The Proposed Rule does give operators subject to the flaring prohibition (but not those subject to the venting prohibition) the option of applying for an alternative flaring limit. But operators should not be put to the time and expense of demonstrating to BLM under the Proposed Rule what they have already demonstrated to BLM under NTL-4A—i.e., that the flaring they are doing is not a "waste" of gas. The demonstrations required by NTL-4A having been made to BLM's satisfaction, BLM now bears the burden of explaining with supporting facts why the NTL-4A approvals that were based on those demonstrations should be set aside. Unless BLM provides such an explanation based on the particular circumstances of each

operator, operators with approval to vent and flare under NTL-4A must be exempted from the Proposed Rule's venting and flaring prohibitions. If BLM were to retroactively reverse course on currently approved venting and flaring, many well would need to be plugged and abandoned, resulting in the loss of otherwise economically recoverable oil and natural gas reserves.

3. The 1,800 Mcf/month flaring limit is arbitrary

As explained above, BLM's MLA authority is limited to requiring that operators take "reasonable precautions" to prevent "waste" of gas. The Proposed Rule is based on the notion that a "reasonahle precaution" would be to limit the amount of gas that can be flared from each well to 1,800 Mcf/month. For three reasons, however, the proposed limit is arbitrary and should not be promulgated.

First, as explained above, the limit is arbitrary as applied to operators who are currently flaring with BLM's approval. Unless and until BLM can justify, on case-by case basis, the setting aside of those approvals, any imposition of a new limit is arbitrary.

Second, the limit is arbitrary as applied to leases issued after the effective date of the Proposed Rule because it makes no allowance whatsoever for the widely varying circumstances of the leases and the wells drilled on them. Under the Proposed Rule, if a well is drilled on a lease that is issued after the effective date of the Proposed Rule, it is subject to the flaring limit, regardless of the circumstances. NTL-4A, on the other hand, has wisely recognized for over 30 years the undeniable fact that there are a variety of factors that must be taken into account in determining whether gas from a particular well can be economically captured. It therefore provides all operators, regardless of when their lease was issued, the opportunity to seek an exception from NTL-4A's general prohibition against venting and flaring on a well-by-well basis. In the preamble to the Proposed Rule, BLM justifies its change of course on the backlog of sundry notices awaiting approval. While we are concerned with this backlog of sundry notices, we would argue that BLM's resources could be better put to use by addressing that backlog, rather than embarking on a time-consuming new regulatory process.

Third, the 1,800 Mcf/month limit is itself arbitrary, regardless of how it is applied to different classes of operators. "To select an appropriate numeric limit for flaring," BLM simply "analyzed data indicating the average flaring rates across wells."[20] Based on that analysis, it then calculated the number of the oil wells that would be impacted by limits of 1,200, 1,800, 2,400 and 3000 Mcf/month. For example, it calculated that a limit of 1,800 Mcf/month would "impact about 16 percent of the oil wells flaring associated gas." It then chose the 1,800 Mcf/month limit, not because of its effect on preventing "waste" of gas, but because, it "would effectively maximize flaring reductions while minimizing the number of affected leases."[21]

Fourth, BLM's own economic analysis recognizes that, at best, the proposed flaring limit benefits are highly uncertain. At worst, those benefits could be negative by as much as $10 million, indicating a net cost to society[22].

What is entirely missing from BLM's analysis is any attempt at all to calculate how much "waste" each of the flaring limits it considered would prevent. Reductions in flaring, which is the only metric BLM used, do not equate to prevention of "waste." There is no linear relationship between the two concepts, as witnessed by the amount of flaring that is taking place pursuant to NTL-4A approvals, and is therefore not a "waste" of gas. Unless and until BLM can demonstrate the effect that the 1,800 Mcf/month limit will have on reducing "waste," it is an entirely arbitrary limit that may, in fact, require significant reductions in flaring that is not "waste." On the current record, it is obvious that BLM, in proposing the 1,800 Mcf/month flaring limit, is interested only in reducing flaring solely for the sake of reducing flaring, and its associated methane emissions, rather than reducing flaring for sake of preventing "waste" of gas.. As explained above, however, BLM does not have authority under the MLA to require operators to take "reasonable precautions" to prevent flaring; it only has authority to require operators to take "reasonable precautions" to prevent "waste." Due to BLM's lack of analysis, it

[20] *Id.*
[21] *Id.* at 6640. This, of course, is not true. A 1,200 Mcf/month limit would "maximize" flaring reductions, while a 3000 Mcf/month limit would "minimize" the number of affected leases.
[22] *Id.* at 6620

is impossible to discern whether the 1,800 Mcf/month limit is a "reasonable precaution" against "waste."

The 1,800 Mcf/month number was derived from the Utah and Wyoming state rules, referenced below, that are totally unfit as models for a nationwide standard. Utah's flaring limit of 1,800 Mcf/month is set forth in 1988 in Section 1.1 of Utah's Administrative Code, R649-3-20 *Gas Flaring or Venting.* Utah's decision to adopt the limit was based on the unique operational and geologic conditions in the Altamont Bluebell field in Utah's Uinta Basin during the 1970s and 1980s. The Altamont Bluebell field is a vertical play; even today, little horizontal drilling exists as compared to other large unconventional plays. Geologically, the reservoir is primarily tight sandstone with extensive natural fractures. The main hydrocarbons are a high paraffin crude oil, known as "waxy crude" that is substantially different in its chemical composition from the light shale oils being developed in today's unconventional plays in the Bakken and Permian basins.

BLM's proposed flaring limit a one-size-fits-all solution rather that fails to recognize that different regions have different challenges. The proposed limit on flaring is so far from reality in certain basins that it would make future development of federal oil wells nearly impossible. The proposed limit is based on a limit that was developed for conventional plays in Utah and Wyoming with adequate infrastructure that have been primarily developed with vertical wells. However, today's unconventional plays allow one well to replace four or even eight conventional vertical wells. Overall, this trend offers tremendous environmental benefit by greatly reducing the surface impact of development. Notably, though, these new horizontal wells are replacing many vertical wells and have commensurately higher production. These unconventional plays are relatively new, which means that the full development cycle of a field is not yet fully understood. Some operators have found that GOR actually increases as unconventional wells decline. This could have potentially complicating implications for long-term development, particularly under extremely tight flaring limits.

According to one New Mexico operator, BLM's proposed 1,800 Mcf/month flaring limit would cause them to reduce the amount of production so significantly that they would only

produce 17 barrels of oil a day (BOD). Currently, the average GOR of this particular operator's wells in New Mexico is 3,500 scf producing an average of 68 BOD. Limiting flaring to 60 Mcf per day, given their GOR, would, in turn, cause them to limit oil production to 17.1 BOD. Requiring operators to limit production to 17 BOD significantly impacts their ability to cost-effectively operate these wells. Operators have predetermined fixed costs that cannot be paid if they have to curtail their production. This will further impact their ability to drill additional wells as their cash flow declines. Not only will operators' cash flow plummet, but so will the federal and state governments' stream of income which depends on royalties—again directly contrary to the stated purpose of the proposed regulations. This also greatly impacts private mineral owners with royalty in federal CAs or units. To meet these thresholds in the Bakken, additional equipment must be installed to shut-down wells based on a flare meter. Pigging will also be problematic, as it requires maintaining flow even as pressures go up and will result in increased flaring. A solution involving well shutdowns will lead to cycling across the whole field as various operators turn production streams off/on. Equipment failures will increase in areas constrained to make sales.

Bakken wells produce more than twice the oil and about 1.5 times more gas in the first month of production than an Altamont Bluebell development well. After the first year of production, the typical Bakken well produces 140 barrels of oil per day (bopd)/150 Mcf per day (Mcfpd). By comparison, production after the first year from Altamont Bluebell wells averages 53 bopd/120 Mcfpd. There is also a vastly different scale of development between the two fields. Since 2000, only 462 wells have been developed in the Green River or Wasatch formations in the Altamont Bluebell field. In the Bakken, 10,629 wells have been developed in the Bakken or Three Forks formations during that same time.

In certain areas of the Bakken, an operator may exceed the proposed 1,800 Mcf/month limit in a period of hours, as GOR can be up to 4 Mcf/bbl. What is lost in BLM's monthly limit is proportionality to the well. A horizontal well equates to several vertical wells, in the range of eight to twenty, depending on the number of frack stages and the length of the lateral. Applying the same flaring limit to a low volume vertical well as to a horizontal well equivalent to multiple vertical wells is simply not logical.

In the Permian Basin, the problem is also severe. One member reports its production from federal wells averages 68 bopd/238 Mcfpd. The Southwest New Mexico portion of the Permian Basin contains over 4 million acres of federal minerals with 2,350 well developed since 2010. As a result, increasing gas capture in the Permian is an entirely different undertaking compared to the relatively modest volumes produced in Utah's Altamont Bluebell filed.

Even after applying the flexible monthly averaging proposed by BLM, there is no way around the basic reality that BLM is two orders of magnitude apart from the on-the-ground reality in unconventional plays. That means that per-well gas production in some unconventional plays may 100 times greater than BLM's proposed flaring limit. The economic impacts on Permian and Bakken wells will be significant on both existing leases and future development. Even after applying the flexible monthly average limit, these volumes are too low for Permian and Bakken operations and will significantly impact well economics on existing leases and future development if/when the infrastructure catches up.

4. BLM fails to consider the most important factors affecting the availability of pipeline infrastructure

BLM states that "the primary alternative to flaring associated gas from oil wells is to capture [it], transport [it] in pipelines, and process [it] for sale."[23] BLM states further that the primary reason that more gas is not being captured and transported in pipelines is that "[i] n some areas, there is capture infrastructure, but the rate of new well construction is outpacing infrastructure capacity," while in other areas, "capture and processing infrastructure has not yet been built out."[24] Thus, in order to justify imposing a flaring limit on operators – which is based on the assumption that operators could capture more gas than they currently are – BLM must demonstrate that its Proposed Rule will solve the problem of pipeline availability. Without solving that problem, operators will have little chance of meeting the flaring limit and its imposition on them will be arbitrary.

[23] *Id.* at 6619.
[24] *Id.*

In BLM's view, the primary reason that capture infrastructure is not available is that "in a new field, operators and the midstream processing companies that commonly build and operate gas gathering and processing infrastructure may not have sufficient information about how much gas will be produced to invest in building gathering lines and processing plants."[25] It therefore proposes to solve this problem by requiring in section 3162.3-1(j)(4)(v) that operators develop and submit a "waste minimization plan" with each Application for Permit to Drill (APD) that includes a "[c]ertification that the operator has provided one or more midstream processing companies with information about the operator's production plan, including the anticipate completion dates and gas production rates of the proposed well or wells."

In designing its solution to the problem of pipeline availability, however, BLM "entirely failed to consider [two] important aspect[s] of the problem," and its solution is therefore arbitrary and destined to fail.[26] First, BLM assumes that gas capture infrastructure will be developed in advance of proven oil production and increased field development if operators would only share information about their project production rates with midstream processing companies at the time it submits an APD to BLM. However, in reality, operators must first prove production for a new oil play and initiate larger scale development before the midstream processing companies are willing to invest capital in new facilities or in the expansion of existing facilities. Just sharing "projected gas production rates" with midstream processing companies is not enough.

Second, BLM completely overlooks the most significant reason why new production outpaces infrastructure capacity—i.e., the time-consuming process of obtaining the necessary pipeline rights-of-way from BLM. The process of obtaining the necessary rights-of-way can sometimes take years. In these situations, operators are left with no choice but to flare associated gas from production or shut in their wells.

The following provides illustrative details of the time needed to obtain approval to construct a pipeline across federal land, including tribal land, in this case, the Fort Berthold

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[25] *Id.*
[26] Motor Vehicle Mfrs. Ass'n v. State Farm Ins., 463 U.S. 29, 43 (1983).

Indian Reservation. It does not even take into account the time needed to obtain the necessary approvals to cross state and private land:

1. Obtain permission to survey (PTS) from landowners and submit to BIA (Bureau of Indian Affairs) New Town office for approval. ***(4 weeks)***

2. "Soft stake" the pipeline centerline after PTS has been granted by BIA (surveying company/ engineers). ***(1 week)***

3. Schedule Environmental Assessment (EA) onsite with representative from the BIA-New Town office. ***(1 week)***

4. Prepare final plans. ***(3 weeks)***

5. Prepare and send scoping letter for approved pipeline (if applicable, for trunk lines only, lateral lines to well locations will not require scoping). ***(4 weeks)***

6. The EA cannot be submitted until the end of the 30-day comment period

7. Schedule Right-of-Way (ROW) onsite with the BIA-New Town office. ***(1 week)***\

8. Prepare EA and cultural reports; from initial surveys conducted in step 3. ***(12 weeks)***

9. If habitat for a listed endangered/threatened species is present, an informal consultation with the US Fish and Wildlife Service (USFWS) is required. Project must reeeive concurrence from USFWS. ***(8 weeks or longer)***

10. Submittal of EA to BIA Aberdeen office and Finding of No Significant Impact (FONSI) is reached. ***(4 weeks)*** There is a 30-day notice period after the FONSI is issued

11. Pipeline Company obtains landowner signatures agreeing to terms and payment. These signatures are then filed in the ROW application that is submitted to the BIA New Town office for approval. ***(4 weeks)***

12. Construction operations can begin only after the BIA issues a Notice to Proceed and ROW grant. ***(5 weeks)***

The above-described times for completion of each stage will increase depending on: BIA onsite schedule, completeness of supplementary information, results of resource surveys, results of onsite surveys, completeness of application packages, public response to projects, weather conditions, and, of course, securing proper consents from all necessary landowners.

If BLM is serious about reducing flaring that occurs, by its own analysis, because "the rate of new well construction is outpacing infrastructure capacity," then it must it must design a rule that facilitates the timely and predictable processing and approval of pipeline right-of-way applications.

5. BLM fails to establish a rational connection between "the factors driving flaring" and the choices it made in the Proposed Rule

BLM "recognizes that ... operators do not want to waste gas," as it is "a valuable commodity that operators can sell at a profit."[27] Yet the need for the Proposed Rule is based on the premise that notwithstanding that powerful economic incentive, operators are "wasting" a substantial amount of gas through venting and flaring and must therefore be prevented from doing so. Accordingly, to justify its Proposed Rule, BLM must explain why the operators are acting against their own economic self-interest, and why and how its Proposed Rule is necessary and effective to change that behavior.

In addition to the lack of capture infrastructure, which is discussed above, BLM gives four other explanations for why operators are allegedly "wasting" so much gas in spite of the economic incentive they have to capture it. First, BLM asserts that because the "the economic

[27] *Id.* at 6638.

return on oil production is substantially higher than the economic return on gas production ... there is an economic incentive for individual operators to focus on oil development at the expense of gas-capture."[28] But operators' focus on oil development is an entirely rational one, and it is one that presumably benefits the federal government in the form of higher royalties, which is one of the principal goals BLM claims it is seeking to achieve through adoption of the Proposed Rule. This explanation therefore does not provide a rational basis for the Proposed Rule's requirement that operators capture more gas where "the economic return of oil production is substantially higher than the economic return on gas production," as doing so will work to the economic detriment of both the operator, the federal government, the public and Indian tribes.

Second, BLM asserts that some operators simply lack "awareness of the available cost savings" from capturing more gas, and thus "fail to capture the economic benefits of investing in waste reduction measures."[29] But BLM offers no support for its inherently implausible assertion that operators are ignoring significant cost saving opportunities. Accordingly, it is reasonable to conclude that there must be some other reason that would explain their behavior. Indeed, as discussed above, BLM completely overlooks one of the primary reasons why are operators are not capturing more gas, which is that, in spite of the best intentions of operators and pipeline companies, the build out of the pipeline infrastructure that is needed for gas capture is heavily dependent on the pipeline companies receiving in a timely fashion the necessary rights-of-way from BLM, state, tribal and private landowners. Those approval processes can take an inordinate amount of time. Moreover, even if BLM were correct in its assertion about lack of operator awareness, it does not take a complex command and control regulation of the type that BLM is proposing to solve the problem. BLM could simply provide the operators the information of which it claims they are unaware, and then let the strong economic incentive that they already have motivate them to capture the gas.

Third, BLM notes that some companies fail to invest in gas-capture technologies because of "limited capital availability."[30] Where this is the case, the problem will not be solved by the Proposed Rule. Instead, by placing an arbitrary and across-the-board limit on the amount of gas

[28] *Id.*
[29] *Id.*
[30] *Id.*

that can be flared, the Proposed Rule may cause operators to forego development of certain oil reserves entirely. In the example referenced above, a Permian operator reporting a field average of 68 bopd/238 Mcfpd would be forced to choke back its oil production from 68 bopd to 17 bopd in order to meet BLM standards. That translates into a 75% decline in production, and consequently in revenue and royalties. Besides limiting the economic viability of oil development in that particular basin, it represents a waste of resources, which should be considered antithetical to a rule proposing to minimize "waste."

Fourth, BLM underestimates the fact that even when gathering infrastructure is in place, some flaring and venting may be unavoidable due to gas quality, plant processing capacity, maintenance and other factors. Under NTL-4A, flaring due to equipment failures, relief of abnormal system pressures, or other conditions resulting in short-term venting or flaring is authorized without incurring royalty obligations. These situations often occur over a short period of time and may come with little to no notice. Generally, they are outside of operators' control and even close coordination between upstream and midstream companies will not eliminate them entirely. To assume otherwise would be unreasonable.

Finally, BLM asserts that "operators typically consider only the costs and revenues of gas capture with respect to their individual operation," and that "in many instances, when costs and revenues are evaluated across a larger area, ... gas capture ... may be more economical."[31] However, operators can only "consider ... the costs and revenues of gas capture ...across a larger area" when they control the assets in that larger area, which is often not the case. They do not know, and cannot consider, the "costs and revenues of gas capture" of their competitors.

As BLM fails to establish a rational connection between the factors it believes are driving flaring and its proposed solution of requiring operators to provide more information to "midstream processing companies" at an earlier date, and complying with one-size-fits-all venting and flaring limits, the solution is arbitrary.

[31] *Id.*

6. BLM has not demonstrated that it will have the resources necessary to administer the Proposed Rule in a timely fashion

The Proposed Rule would place significant new responsibilities on BLM, as set forth in sections 3162.3-1, 3197.7, 4179.10, 3179.11, 3179.201, 3179.202, and 3179.401. BLM's ability to perform those responsibilities in a timely manner is key to the successful working of the Proposed Rule. Yet the preamble contains no estimates of the additional resources that BLM will need to administer the Proposed Rule, nor any assurance that those resources will be available to it, nor does it set any deadlines for BLM's fulfillment of its responsibilities so that operators can reliably plan their operations.

BLM is already failing to timely fulfill its current oil and natural gas program responsibilities, particularly with respect to the approval of APDs and pipeline rights-of-way across federal lands. This latter failure is particularly significant in light of the Proposed Rule's effort to stimulate the timely building of more pipeline infrastructure so that more gas can be captured. Thus, before any final rule is promulgated, it is imperative that BLM assess and disclose to the regulated community whether it will be able to effectively administer the rule with the resources available to it. Just as BLM was required to quantify the time burden and costs that the information collection requirements of the Proposed Rule will impose on the public, so should it be required to quantify the time burdens and costs that the Proposed Rule will impose on itself, and to demonstrate that it will be able to fulfill its new administrative responsibilities in a timely fashion. BLM should not impose significant new requirements on the oil and gas industry without demonstrating that it will not become a bottleneck in the industry's efforts to comply with those requirements.

7. BLM's Regulatory Impact Analysis is deeply flawed and does not support adoption of the Proposed Rule

We have attached a thorough analysis of the Regulatory Impact Analysis ("RIA") on which the Proposed Rule is based. The analysis demonstrates that the Proposed Rule will impose costs of $1.26 billion annually to the economy, and that those costs far outweigh even the

highest end BLM benefit estimate of $384 million.[32] This is based on a price for natural gas of $2.00/Mcf.[33]

This year, natural gas prices have dropped to as low as $1.57 per million BTU and $1.40 Mcf according to the EIA and media sources. Discounting the idea that a reduction in potential methane emissions would have any benefit on the environment that could be monetized, a more reasonable calculation of the potential benefit of the Proposed Rule would be $90 million. With a cost of $1.26 billion and a potential benefit of just $90 million, the Proposed Rule does not produce a net social or economic benefit. Additionally, those economic losses create an additional loss of $114,112,000 in federal and state taxes.

The benefits as laid out by BLM are also speculative at best as they rely on passage of EPA Subpart OOOOa and on certain flawed assumptions that methane gas reductions have a social cost benefit.

In addition to not completing the RIA in accordance with published OMB guidelines, BLM included a number of assumptions that were on their face either false, or should not have been used as part of this type of analysis. The most glaring problem, however, is BLM's inflated commodity price estimates which underlie the economic benefit estimate in an economy where commodity prices, significantly for oil and natural gas, are in their biggest bear market in 30 years. Additionally, the central purpose of any regulation is to have an in-depth safety focus, which is not examined in any real depth in this RIA, especially when limits for venting or flaring per well are suggested as a remedy in a very broad context.

BLM's failure to conduct a comprehensive alternative analysis was clearly in violation of the OMB guidelines. An alternatives analysis may have shown that the proposals could actually lead to increased and significant economic costs to the oil and gas industry.

In addition to the flaws in the RIA, the Associations are concerned by the numerous instances where BLM ignores significant economic burdens that would result from its Proposed

[32] Op. cit. Regulatory Impact Analysis, pages 6-8.
[33] Op. cit. Regulatory Impact Analysis, page 42.

Rule. This is particularly evident in the proposed flaring limits, but runs throughout the Proposed Rule. BLM generally underestimates or ignores entirely the development costs in terms of both time and capital with building out pipeline infrastructure. The proposed flaring standards, when applied broadly, will severely limit producers' ability to develop oil wells and will discourage investment in new plays. BLM's economic analysis understates the complexity of the economics of developing pipelines.

In the immediate term, the effects of the Proposed Rule will be pronounced, but in the longer term it means that the domestic energy renaissance we have recently witnessed would be extremely difficult to sustain. The overwhelming capital costs of developing new fields and expanding current fields into new areas would strongly deter investment and would have lasting economic, geopolitical and environmental consequences in this country. In addition to the potentially severe economic consequences the proposed rule would create, BLM failed to fully contemplate the environmental impacts of its proposal. Since oil and natural gas can be produced in many different countries the regulations may simply transfer activity from the United States to Russia, Mexico, Iraq or Nigeria. This can not only impact the American economy but could also lead to increased methane production.

8. BLM overstates the effectiveness of remote gas capture technology

In the preamble of the Proposed Rule, BLM describes several alternative gas capture technologies that it believes can be used as an alternative to flaring. However, in support of this, BLM relies heavily on the Carbon Limits study that bases its assumptions on gas prices that are more than double today's market value of natural gas. BLM goes on to suggest that due to these remote capture technologies, "[w]hile flaring in these situations has generally been considered unavoidable, the BLM believes this assumption is challenged by the development of the alternative capture technologies described above, which calls into question whether it remains reasonable to assume that there are no alternatives to flaring when a field produces only a small quantity of natural gas."[34]

[34] *Id.* at 6637.

This selective review of remote capture technology fails to acknowledge the overwhelming evidence from on-the-ground experience with these control strategies. Numerous operators have deployed remote gas capture technology in the field, and their experience has clearly demonstrated that in the vast majority of cases, this technology is not economically viable.

Additionally, the expanded use of remote natural gas capture technology would necessitate expanding the footprint of many wellpads to safely accommodate the additional equipment. The emissions, noise, and dust associated with the additional construction requirements would have environmental consequences that BLM has failed to fully consider. The installation, operation, and maintenance of these remote capture facilities would also require additional truck traffic, resulting in additional vehicle emissions.

According to one North Dakota operator, "based on its extensive evaluations of remote capture technology, [we have] concluded that the technologies are not economically viable given their substantial cost in comparison to the nominal value of gas being flared.... To the extent that they are economically viable at all, remote capture technologies have the greatest likelihood of providing an economically viable alternative to flaring when the technologies are deployed to capture gas flared from stranded wells (i.e., wells incapable of being connected to a pipeline). Unlike wells connected to pipelines, which intermittently and unavoidably flare negligible volumes of gas, stranded wells flare larger volumes of gas..."

Another operator found, "[o]ur efforts to date establish that remote capture technology is uneconomic and will not alleviate flaring or resolve pipeline capacity and constraint issues."

A third operator noted, "[t]he remote capture technologies presently available are uneconomical and they do not entirely resolve gas flaring. The lease cost of the remote capture units (NGLs) are greater than the value of the natural gas liquids they produce at current market prices.... NGL units are notoriously difficult to winterize and have low winter runtimes. NGL units require semi-stable inlet gas rates to run; many connected sites flare intermittently which would make operation difficult and runtimes low. NGL units require a large footprint to safely operate, which is an issue on smaller pads. [Current] vendors are not able to scale down further

than 250 [Mcfd], which is greater than the amount of flaring on most connected sites. Additionally... the NGL unit will reduce but not eliminate the flare."

One operator developed an economic model that represents a theoretical application of remote capture technology in which 12 months of gas capture is required to satisfy regulatory requirements for a new location. This model is based on average costs incurred over 15 locations during 2014, and pricing believed to be available in October 2015. A unit with 2,000 Mcfd capacity was selected to match with production forecast in month 4 of production. Prior to month 3, some gas will be flared. After month 3, the equipment will be underutilized. A location gas capture goal of 85% is assumed.

The following assumptions were made:

Gas Capture Unit Capacity: 2,000 Mcfd

Direct Service Costs Including:

Mobilization and installation charges

Costs of moving equipment to location, cranes, pipe, valves, and fittings, roustabout work, electrical installation, hydrostatic testing, and commissioning. Assumed equipment is moving from gulf coast.

Monthly fees to service company

Includes lease, operation, and maintenance of compressors (2), mechanical refrigeration unit (2), stabilizer (2), natural gas generators (2), product storage tanks (2), and waste tank (1).

Project term: 12 months

Demobilization fee at term end

Includes breakdown and removal of piping, electrical, crane, and trucks to lift and remove equipment skids from location

Total payments to gas capture operator: $750,000

Company Costs: $124,430

Site preparation

Company oversite billed to location

Company gas capture supervisor on location 8 hours per week during operation, plus one company consultant on location 8 hours per week during operation. Excludes cost associate with field safety and environmental personnel, and administrative costs.

Tie-ins to gas plan

Includes custody transfer gas supply meter to gas plant and meter for residue gas stream to flare, and piping required to connect treaters to gas plant

Total Costs for Four-Month Operation: $874,430

Production Data

Equipment availability assumed: 90%

Total gas processed: 492,750 Mscf

Assumed that 75% utilization of available capacity is used due to production decline below equipment capacity maximums

Average gallons extracted per Mscf processed: 2

Total NGLs extracted and sold: 985,500 gallons

2015 Economics of Project

Average revenue per gallon after	$0.22

transportation, fractionation, and marketing	
Total project revenue	$216,810
Total project costs	$874,430
Net project profit/(loss)	($657,620)

This economic analysis underscores how critical it is for BLM to recognize current commodity prices in its analysis. Using an outdated study based on inaccurate price data tells a vastly different story than an analysis based on current economics. As the above analysis based on real-world market conditions demonstrates, BLM's belief that these types of remote capture technologies are economical cannot be supported.

III. SECTION-SPECIFIC CONCERNS

Many of the provisions that we discuss below have been addressed by EPA in its proposed rule for new and modified sources of emissions or will be addressed by EPA in the rule that it is now developing to address existing sources of air emissions from oil and gas operations. These include venting and flaring limits, Leak Detection and Repairs (LDAR), replacing high-bleed pneumatic controllers and pneumatic pumps, and limiting emissions from downhole well maintenance and liquids unloading. Consistent with BLM's policy, which is to avoid mandates that would be duplicative of, or conflicting with, those imposed by EPA, BLM should defer to EPA on this issue and not proceed with its proposal. If BLM chooses to promulgate the provisions in spite of their arbitrary nature and BLM's lack of authority to do so, then it must address the following concerns that we describe below.

A. Actions to reduce the "waste" of gas

1. Prohibiting venting of associated gas

Section 3179.6(a) "would require operators to flare all gas that is not captured, except under certain limited circumstances."[35] The Proposed Rule states that the "operator must flare rather than vent any gas that is not captured."[36]

As explained above, this prohibition should not apply to operators with current NTL-4A approvals. However, regardless of to whom it applies, it is not a "reasonable precaution" against the "waste" of gas, and should not be promulgated. As explained below, a total cessation of venting is not feasible in many instances for safety and economic reasons. Moreover, it is grounded in a concern for the reduction of methane emissions, rather than in a concern for the prevention of the "waste" of gas, as is required by the MLA. If BLM chooses to promulgate the prohibition, in spite of its arbitrary nature and lack of authority to do so, then it must address the following concerns.

1. The Proposed Rule's stipulation of a "no venting" standard is highly problematic and fails to acknowledge the operational realities of the oil and natural gas industry. Operators minimize the venting of gas whenever possible for economic and safety considerations. Venting is generally avoided when it is feasible and practical to do so.

However, there are situations when a "no venting" standard is impossible to meet. There are numerous instances where a *de minimis* volume of gas will be vented and any attempt to capture that gas would be technically and economically infeasible. For instance, during drilling operations, there are very small volumes of gas entrained in drilling mud. When mud is processed, small pieces of drilling cuttings are filtered out using devices like mud shakers. During the process of removing these cuttings, some of the gas entrained in the drilling mud will be released into the atmosphere. These volumes are exceedingly low and have virtually zero economic value, and it would be impossible to completely eliminate these emissions in meeting a

[35] *Id.* at 6666.
[36] *Id.* at 6682.

"no venting" standard. Other instances in which such a standard is infeasible would be when small amounts of gas have to be vented to blow and depressurize equipment to work on it. We ask BLM to clarify that these instances would be clarified in its clause on technical infeasibility.

Other situations may involve low API gravity oil production from certain wells. In instances where the gas-to-oil ratio (GOR) is low or an oil is particularly heavy there may be very low volumes of associated gas that cannot be feasibly separated out at the wellhead. In these instances it is unrealistic and unreasonable for BLM to expect operators to totally eliminate venting.

Permian Basin production offers another example of the infeasibility of a "no venting" standard. A significant amount of associated gas is produced with horizontal drilling in the Permian Basin. Many wells do not have gas in the formation downhole, but rather it is actually dissolved in the oil and water and is only present as the pressure is reduced on the liquids. This pressure drop occurs when the oil and water are sent from the flowback separator at 50-200 psi to the tanks which are at atmospheric pressure. There will always be some gas that comes out of solution during this process and is vented through the tanks.

If BLM adopts a venting prohibition, then it must clearly allow an exception for the venting *de minimis* volumes like the examples describe above; requiring operators to eliminate venting entirely is impossible given today's technological and economic constraints.

2. It is clear from the preamble that the prohibition is intended to apply only to venting from development oil wells, but the Proposed Rule does not so state. Accordingly, section 3179.6(a) should be revised to state that "the operator of a development oil well must flare rather than vent any gas that is not captured."

3. While section 3179(a) of the Proposed Rule states that the "operator must flare rather than vent gas that is not captured," section 3179.6(b) states that an operator "must not flare or vent gas" (emphasis supplied) in excess of the limits that the Proposed Rule establishes, thus appearing to allow an operator to continue to vent gas as long as the total volume of gas that is

flared or vented is not in excess of the limits. If this is what BLM intended, it would be preferable to the total prohibition of venting, and should be clearly stated.

4. It is not clear from the Proposed Rule when an operator must be in compliance with the prohibition. Section 3179.9 says that NTL-4A approvals "to flare or vent at a level above the 7,200 Mcf per month limit ..., which are in effect as of the effective date of this rule, will continue in effect until [90 DAYS AFTER THE EFFECTIVE DATE OF THE FINAL RULE]." Does that mean that approvals to flare or vent at a level below the 7,200 Mcf per month limits will remain in effect in accordance with the 3 year phase-in set forth in section 3179.6? That would be preferable to the flat cut-off of all venting as soon as the Proposed Rule becomes effective that is suggested by the language of section 3179.6(a). Obviously, operators cannot be expected to cease all venting from one day to the next.

2. Setting limits on the flaring of associated gas

To address the waste of associated gas from flaring, the Proposed Rule proposes to "establish a limit on the average rate at which gas may be flared of 1,800 Mcf per producing well on a lease" per month. The limit will apply immediately to new wells, and after a two-year phase-in period to existing wells. For the following reasons, the proposed limit is arbitrary and should not be adopted by BLM.

As explained above, the limit is arbitrary as applied to operators with existing NTL-4A approval to flare above the limit, and to operators of new wells.

The limit is also arbitrary because it is based on outdated economic data. BLM apparently took its cue for the establishment of flaring limits from a 2010 GAO Study, which was entitled "Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared natural Gas Which Would Increase Royalty Payments and Reduce Greenhouse Gases" ("GAO Study").[37] As an explanation of the need for its rulemaking, BLM states that "GAO found that 'around 40 percent of natural gas estimated to be vented and flared on onshore Federal leases

[37] GAO-11-34 (Oct. 2010).

could be economically captured with currently available control technologies.'"[38] Using 2008, the RIA cites a GAO estimate that about 128 billion cubic feet of natural gas was either vented or flared from Federal leases, of which 50 billion cubic feet was economically recoverable.[39] This recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon monoxide equivalent emissions.

This reasoning, however, does not reflect the current state of the market. First, the average natural gas price for the full year 2008 was $8.85 per MCF, as compared to the spot price of natural gas in March of 2016 which is $1.40 on March 14, 2016.[40] This is an 84 percent drop in the price of natural gas since the 2008 time frame used in the RIA. Based on the 84 percent reduction in the price of natural gas, the $23 million dollar figure presented by the BLM would drop to $3.68 million.

If BLM chooses to proceed with adopting the limit in spite of the arbitrariness of the limit and its own lack of authority, then the following concerns need to be addressed.

1. Under the Proposed Rule, alternative limits may only be granted if the operator can demonstrate that complying with the required limits "would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves." But the flaring limits alone may not be the sole determining factor in a well's economic viability. The Proposed Rule imposes layers of cost through a variety of requirements – e.g., the cost of replacing high-bleed pneumatic controllers, the cost of developing and implementing a leak detection and repair (LDAR) program, the added administrative burden of recordkeeping and reporting for federal wells, etc. Operators don't make decisions about these costs in a vacuum; they are considered in concert. BLM should allow for similar considerations as part of the alternative flaring limit requirements. One factor alone may not be enough to render a well uneconomic, but the myriad and burdensome requirements of the Proposed Rule might when taken together. The total cost of

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[38] 81 FR 6617.

[39] Government Accountability Office, *Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases,*. GAO Report 11-34, October 2010, at: www.gao.gov/new-items/d1134.pdf.

[40] Braziel, E. Russell, The Race To Liquids, Oil & Gas Finance Journal, August 1, 2010, on-line at: www.ogfj.com/articles/print/volume-7/issue-8/features/the-race_to_liquids.html; CNBC.com for March 14, 2016 natural gas price.

implementing the Proposed Rule is certainly relevant to an operator's determination about whether it can afford to continue to produce from a well, and the total cost of implementing the Proposed Rule should therefore be relevant to BLM in determining whether to grant relief from the Proposed Rule's requirements. Moreover, the granting of an alternative limit should not depend on a demonstration that without such a limit there will be "significant" abandonment of oil reserves. That would mean that to prevent the "waste" of some gas through flaring, BLM could, in effect, force operators to "waste" substantial amounts of oil and gas by leaving it in the ground.

2. There is no explanation on treatment of waste gas from the remote capture technology—i.e., after the NGLs are removed, the remaining gas goes to flare and should be considered unavoidable and not included in limits or royalty calculation. The North Dakota Energy and Environmental research committee evaluated remote capture technology. Its conclusion is summarized in the following: "New Technology Investigations. The Energy & Environmental Research Center." EERC conducted an assessment of alternative gas uses upstream of traditional gas-processing plants. The study investigated using associated gas for power production, transportation fuel, and chemical production, as well as analyzed small-scale gas processing to recover NGLs. Although intriguing, the economic viability of these alternatives was complicated by the distributed and transient nature of flared gas, requiring innovative approaches to effective implementation."[41] This reinforces the belief that the gas is not wasted but is an uneconomic byproduct of the oil production.

3. The flaring limits cannot be reasonably enforced with Federal and Non-Federal wells on the same gas sales line. Non-Federal well will make sales and block Federal wells, thus competitively ruining production on Federal land.

4. With respect to alternate flaring limits, no valuation of flared gas is provided. Flared gas cannot be valued the same as sales gas because it must properly account for implementation of a redundant gathering system. When these added costs are considered, the netback price of the gas is essentially zero.

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[41] https://www.undeerc.org/bakken/Reduced-Gas-Flaring.aspx.

5. BLM proposes that under § 3179.8, "operators would need to estimate or measure all volumes of gas vented or flared" which includes "flaring of associated gas, and flaring that occurs during well drilling (proposed § 3179.101)...". This is technically infeasible. Gas flow meters require a steady stream of gas to be accurate. Drilling operations do not provide the requisite steady stream of gas required. Furthermore, gas rate meters will not work in the presence of liquids – an element often included in the gas stream from drilling operations. In sum, measuring the gas stream from drilling operations is technically infeasible and estimating the gas stream is a highly subjective process. Instead of relying on inaccurate and costly metering, operators should be allowed to use a GOR to calculate total produced gas or measure total produced gas then use calculation: (Total Produced Gas – Lease Use – Gas Sales). Based on our analysis, BLM's cost estimate for flare meters is extremely low. On any given day, an operator could temporarily lose access to natural gas sales and lines and be above 50Mcfd. Based on this reality, BLM's proposed requirements would necessitate a meter on every site production could be greater than 50 Mcfd. Even if sales are not lost, virtually every well will flare > 50 Mcfd at some point due to compressor maintenance, force majeure, and emergencies and would then have to measure. It appears BLM did not consider this factor when estimating the number of impacted sites. In addition, there is no measurement that will accurately measure the very big swings in flow. If flare meters are required for every flare that hits 50 mcfd at any point in time, nearly every flare will require a meter. And the vast majority of those meters will have zero flow most of the time, then spike during temporary periods of flaring. There is no meter on the market that can accurately gauge volumes at a spike period when generally it has no flow. BLM should consider more carefully examining their metering requirements so that meters are only required if 50 Mcfd is estimated for more than 60 days.

6. In many instances, oil and natural gas production and natural gas gathering systems are operated by separate companies. BLM's discussion of third party natural gas gathering systems in the Proposed Rule underestimates the complexity of the agency approval process even with a robus dialog between oil and natural gas producers and midstream system operators. Although companies can and do work together in good faith to ensure resources are developed efficiently and responsibly, market dynamics play an equally important role. A producer cannot

necessarily influence how a midstream operator builds out its gathering system, allocates available capacity, and plans its maintenance schedules, among other decisions. It is unrealistic to place the burden of complying with a standard on an operator that cannot control third party infrastructure. In order to accommodate the many situations that can arise when, despite good faith efforts, operators are unable to utilize gathering systems, BLM should provide adequate exemptions for lack of gathering capacity, maintenance schedules, and other force majeure situations.

This problem is particularly acute in areas like North Dakota. Gas gathering and processing infrastructure exists, but lacks capacity or where new development has occurred without pre-existing infrastructure. Where it is practical, producers will nearly always develop in areas near gas gathering systems. This allows maximum economic and environmental benefits. But it is not always practical to develop near this infrastructure—especially in very remote areas (such as certain parts of North Dakota). Producers do not always have control over how gas gathering infrastructure is used. For example, in some cases, midstream companies may curtail the capacity made available for an operator's associated gas or other constraints. In others, lease terms and other constraints require the resource to be developed on a certain timeline despite dedicated infrastructure. The Proposed Rule appears to assume that availability of gas gathering infrastructure alone will largely solve these problems. In our experience, this is far from accurate. Capacity constraints on existing infrastructure can be both temporary and long-term problems that are very complex to address. Producers and midstream companies work together to minimize capacity constraints but in a dynamic industry like oil and natural gas production, the goal of maximizing gas capture is a constantly moving target. The Proposed Rule risks shutting down significant portions of this industry, which is already strained by low commodity prices. Such consequences are likely to be borne disproportionately by smaller producers.

Further complicating matters, some wells may come online with a high initial production (IP) rate. In these instances, the large volumes of associated gas produced may overwhelm limited gas supply capacity. Operators are left with little choice but to flare that associated gas or risk damage to the reservoir of a highly productive oil well by choking it back. That could

have significant economic consequences for operators as well as mineral owners, including the federal government.

If BLM fails to allow adequate provisions, operators would be forced to consider building out redundant gathering systems which is cost-prohibitive and creates added environmental impact through construction, or curtail production which would decrease royalty payments to the federal government and could potentially permanently damage otherwise productive reservoirs.

7. The proposed natural gas measurement requirements are potentially infeasible in certain situations. Low pressure vapors coming from production sites are difficult to measure, but are more easily calculated. BLM should allow operators to determine flaring volumes through calculation, which has proven to be accurate. Metering simply adds cost and logistical difficulties without providing environmental benefit or reducing waste.

8. By requiring that no flaring take place above a certain limit, the Proposed Rule gives pipeline companies unfair leverage to raise their pipeline usage rates. This has been demonstrated in Utah, which imposes a flaring limit similar to the one in the Proposed Rule.

9. We encourage BLM to defer to state flaring rules where such rules exist, like North Dakota, New Mexico and Texas. By doing so, BLM will create a clearer path for development while still utilizing standards that are protective of the environment.

3. Detecting and repairing leaks

The Proposed Rule would require operators to develop LDAR programs for 'all wells that produce natural gas, ... including oil wells."[42] Operators would be responsible for inspecting for gas leaks on: 1) all equipment and equipment components at the wellhead; 2) all facilities that the operator operates[43]; and 3) all compressors located on the lease, unit, or CA that the operator owns, lease, or operates. BLM estimates that the requirement would affect up to

[42] *Id.* at 6685.
[43] What is meant by "facilities" is not clear. The term needs to be explicitly defined.

37,000-38,000 well sites per year. The requirement is objectionable for several reasons and should not be adopted.

1. The issue of leak detection and repair for existing equipment is an issue that will be addressed by EPA in the rule that it is now developing to address existing sources of air emissions from oil and gas operations, just as it has been addressed by EPA in its rule for new and modified sources of emissions. BLM has already stated that it "expects that the LDAR requirements ultimately adopted [by EPA] for new and modified well sites would be as effective in minimizing the volume of gas lost through leaks as the final BLM requirements" that BLM is proposing in the Rule, and that therefore compliance with the EPA requirements would satisfy BLM's requirements.[44] BLM has no reason to expect that "the LDAR requirements ultimately adopted [by EPA for existing well sites] would be [any less] effective in minimizing the volume of gas lost through leaks" than the requirements that BLM is proposing in the Rule for existing well sites. BLM's own cost-benefit analysis, even if it were accurate,[45] demonstrates that its LDAR requirement cannot be justified solely as a "waste" prevention measure. Therefore, instead of going to the trouble and expense of finalizing those requirements, only to have them supplanted by EPA's requirements, BLM should cease its efforts to develop an LDAR requirement.

2. Although BLM heavily touts the environmental benefits of the Proposed Rule, its proposal would create many negative environmental consequences. For example, in its Environmental Assessment, BLM claims the proposed LDAR program would require one to four truck trips per year to each of the roughly 38,000 wellsites impacted by the rule. This is likely understated given that many repairs could require multiple trips, and possibly multiple vehicles per trip, depending on the nature of the repair. This could add up to 150,000 truck trips or more, with many of these trips would be over many miles to remote locations and could have an impact on the local environment such as crop impacts for wellsites in agricultural areas and impacts to wildlife. Additionally, adverse weather could render many of these trips difficult or impossible at certain times of year.

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[44] *Id.* at 6648.

[45] See the attached economic analysis for an explanation as to why BLM's analysis is incorrect.

3. BLM acknowledges that its proposed approach "is similar to the requirements adopted by Colorado and Wyoming."[46] That being true, it should allow operators in those states to satisfy BLM requirements by applying their state-compliant programs on their federal leases. That would avoid duplicative efforts and unnecessary expense, while achieving substantially the same results in terms of preventing the "waste" of gas.

4. The Proposed Rule would impose sweeping, one-size-fits-all requirements in spite of BLM's acknowledgment of the following facts: 1) the Carbon Limits Study found that "about one-third of the facilities had no detectable leaks;"[47] 2) EPA found "higher volumes of fugitive emissions from gas wells compared to oil wells;"[48] 3) "[m]ultiple studies have found that a relatively small percentage of facilities are responsible for the majority of leaks and for most of the wasted gas;"[49] 4) "BLM believes [based on experience in the field] that there are systematic differences among operators' leak rates;"[50] and 5) most leaks are found in equipment that vibrates.[51] Given these facts, it is obvious that BLM's sweeping requirements do not achieve BLM's own goal of "reduc[ing] the most waste at the lowest cost."[52]

To achieve its goal, BLM should revise its requirements to focus on gross emitting components. The Proposed Rule should focus on: (1) the most common sources of leaks, such as valves, open-ended lines, and pumps, or "high motivated operation equipment;" and (2) only those components with the potential to operate at or above sales line pressure. This would allow operators to maximize the cost effectiveness of their LDAR programs by focusing the most resources on quickly identifying and addressing the largest leaks.

Providing operators flexibility in developing LDAR programs similar to directed inspection and maintenance (DI&M) programs tailored to their specific facilities or groups of facilities would provide significantly greater fugitive emissions benefits at a much lower cost than the type of rigid and inflexible program in the Proposed Rule. See Management of Fugitive

[46] *Id.* at 6647.
[47] *Id.* at 6646.
[48] *Id.* at 6649.
[49] *Id.* at 6648.
[50] *Id.*
[51] *Id.* at 6650.
[52] *Id.* at 6648.

Emissions at Upstream Oil and Gas Facilities, Canadian Association of Petroleum Producers (In the upstream oil and gas sector "[o]nly a small percentage of the equipment components have any measurable leakage, and of those only a small percentage contributes to most of the emissions. Thus, the control of fugitive emissions is a matter of minimizing the potential for big leaks and providing early detection and repair.") Accordingly, we strongly support a flexible approach. Allowing operators to focus monitoring efforts on the components that are most likely to leak, and those that are most likely to have the highest leak rates, maximizes both the emissions reductions and cost-efficiencies of an LDAR program.

5. Section 3179.302 Approved Instruments and Methods – For all practical purposes, the Proposed Rule would require the use of optical gas imaging devices ("OGI") for inspections conducted by operators that operate "500 or more wells within the jurisdiction of a single BLM field office."[53] However, OGIs may not function well in all situations. For example, an OGI is not a quantitative tool and, depending on the camera, it may also detect water vapor and heat signatures. An OGI camera survey may not always be able to tell an operator whether a repair is necessary, since it is not quantitative. During periods of overcast skies, high winds, or inclement weather, OGI technology is unable to effectively detect hydrocarbon vapors. In certain parts of the West, such overcast and windy conditions can persist for long periods during the winter, and as a result operators could likely spend considerable time and money repairing leaks of just water vapor. Lastly, OGI cameras are generally not intrinsically safe and would require a hot work permit in many instances. Due to these numerous technical and practical limitations, it would be inappropriate for BLM to adopt a leak threshold definition. We support BLM's decision to not include such a definition in its proposed rule.

Rather, the Proposed Rule should give operators the flexibility to select the ideal monitoring technology for their particular conditions. Instead of having to obtain BLM's approval before using something other than OGI, operators should simply be required to file with BLM a statement identifying the technology and certifying that it meets or exceeds the effectiveness of OGI in detecting leaks.

[53] *Id.* at 6685.

The Proposed Rule also would stifle innovation of more effective monitoring and measuring equipment. Instead of prescribing two methodologies, the Rule should permit flexibility, in accordance with other successful LDAR programs. For example, in Colorado, 5 C.C.R. 1001-9 (Regulation 7) gives operators some flexibility in choosing a leak detection technology. EPA's vendor testing program for flares and combustors may also be another viable option. Under this program, EPA allows vendors to test according to protocols set by EPA and determine standard operating procedures for control devices. New and innovative technologies are constantly involving in this space and the rule should encourage, not stifle, such progress. We encourage BLM to make very clear in the rule that new technologies are encouraged and will be approved and allowed through a straightforward and expedited review process (i.e., avoiding an onerous, years-long application process that would otherwise be applied to actual emissions control devices or continuous emissions monitoring systems). We would welcome the opportunity to work with BLM to determine what methods should be approved for LDAR monitoring and verification.

6. Section 3179.303 Leak detection inspection requirements - We strongly oppose an inspection schedule that varies in frequency. While we appreciate BLM's intent to create a performance-based program, in practice this approach will create a disproportionately large administrative burden while offering minimal environmental benefit. Instead, we urge BLM to implement a fixed annual inspection schedule.

BLM acknowledges the Carbon Limits Study that demonstrated that annual surveys "generally resulted in net benefits to the operator," and that quarterly surveys imposed net costs on the operator. Second, as BLM is well aware, EPA also concluded that "the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions..."[54]. Further, BLM admits that its proposed inspection requirements with "inspection frequencies that vary over time and across an operator's well sites" can be confusing.[55] Accordingly, instead of burdening operators with a set of confusing inspection requirements that will have small to negative net benefits, the rule should simply

[54] 80 Fed. Reg. 56636.
[55] 81 Fed. Reg. at 6648, 6650.

require annual inspections at all sites. Based on the results of those inspections, BLM should then evaluate its inspection requirements at the end of five years.

The Proposed Rule's LDAR inspection requirements take a one-size-fits-all approach that is impractical for many facilities. To treat a well that produces six barrels of oil per day like a centralized well pad with eight horizontal wells is unrealistic. Stripper wells producing less than 15 barrels of oil equivalent per day (boe/d) do not have the potential to emit at the same rate as larger producing facilities, and should therefore be exempted from the proposed LDAR requirements. Although BLM claims that LDAR at stripper wells will offer significant emissions benefit, industry experience indicates otherwise.

In the preamble of the Proposed Rule, BLM itself recognizes that a one-size-fits-all approach will likely not yield equitable costs and benefits. "EPA's emissions factors indicate generally higher volumes of fugitive emissions from gas wells, compared to oil wells. Assuming these emissions factors are accurate, this indicates that focusing more inspection resources on gas than oil wells would identify and save a relatively larger volume of gas at roughly the same cost." Yet BLM goes on to impose blanket requirements that treat all facilities as equals.

We agree with BLM's assessment that the requirement for OGI only applied to large operators with 500 or more wells per BLM field office. For small operators, the cost of an OGI or Method 21-based LDAR program would be particularly burdensome, and we urge BLM to retain this exemption in the final rule. In some instances, these small operators have only a few wells or wells with low production volumes; and therefore the cost of the equipment or implementing the program may vastly exceed the emissions being saved. As an alternative to expensive instrumental surveys, we recommend that BLM allow for soap bubbles as a potential screening method (only where appropriate, considering the caveats in EPA Method 21, Section 8.3.3.1). EPA already recognizes the effectiveness of soap bubbles in its Method 21, Section 8.3.3 procedure.

We also urge BLM to clarify the phase-in period for its proposed LDAR program. In order to allow companies sufficient time to develop LDAR programs, train staff, and procure

equipment, we suggest a 12-month phase-in. BLM should also provide a variance for state LDAR programs as being sufficient to satisfy BLM's requirements.

BLM also solicits comment on the use of third-party LDAR inspections (81 FR 6649) which we strongly oppose. Under no circumstance should BLM impose this needless burden that is devoid of any environmental benefit. BLM does not have unfettered authority to promulgate regulations that could force the entire industry to change the way in which it designs and operates its facilities or reports information—particularly where the rule has neither demonstrated the need to do so, nor discussed the environmental benefits to be obtained or the costs to be incurred. BLM's LDAR program must be reasonable with respect to its requirements and its consequences. On balance, we do not believe requiring third party certification of LDAR is reasonable.

7. Section 3179.304 Repairing leaks – The Proposed Rule would require operators to "repair any leak not associated with normal equipment operation as soon as practicable, and in no event later than 15 calendar days after discovery, unless good cause exists for repair requiring a longer period."[56] Given the fact that repairs often cannot be made within 15 days due to weather conditions or the availability of parts, BLM should adopt a more realistic repair window of 30 days, with the possibility to extend for an additional 30 days, in the event that parts are unavailable. This would significantly reduce the paperwork required, and that benefit would clearly outweigh the detriment that might be caused by whatever small amount of gas might leak from a particular component during the extra 15 days. We also ask that BLM clarify that decisions regarding feasibility due to weather or "good cause" allow for operator discretion, as they best understand when weather or other conditions can render repair work infeasible or hazardous.

Further, as most companies do not allow hot work without shutting in production, the Proposed Rule should state that where shut-in is required before a repair can be made, the operator shall make the repair immediately after the next scheduled shutdown, but in no event

[56] *Id.* at 6686.

later than six months after the leak is detected. EPA made a similar allowance in its New Source Performance Standards (NSPS) Subpart OOOO regulations, which provide that "[d]elay of repair for equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown."

8. Section 3179.305 Leak detection inspection recordkeeping – The requirement that the report include a "description of the leak" is ambiguous and superfluous. Requiring operators to document the first attempt at repair is also redundant. All that really needs to be recorded is the component on which the leak was found and the fact that it was repaired.

4. Replacing high-bleed pneumatic controllers

The Proposed Rule would require operators to replace approximately 15,600 existing high-bleed pneumatic controllers—i.e., existing pneumatic controllers with a continuous bleed rate greater than 6 standard cubic feet per hour--with low-bleed pneumatic controllers within one year of the effective date of the rule. The requirement is objectionable for several reasons and should not be adopted. If BLM decides to adopt a replacement requirement in spite of the objections noted above, the requirement should be revised as set forth below.

1. The preamble states that the Proposed Rule would require the replacement of pneumatic high-bleed controllers with low-bleed controllers. The Proposed Rule should make clear that high-bleed controllers may also be replaced with intermittent controllers because they are not a significant source of emissions. A 2014 study conducted by Oklahoma Independent Producers Association (OIPA) examined 205 producing wells and 680 pneumatic controllers.[57] The study determined that on average, intermittent vent controllers emitted 0.40 standard cubic feet of gas, a miniscule amount. OIPA's analysis found that prior estimates underestimated the number of vent controllers at visited sites, but overestimated emissions, and overestimated both the number of continuous bleed controllers and their emissions. OIPA's analysis provides further support for allowing intermittent controllers.

[57] Pneumatic Controller Emissions from a Sample of 172 Production Facilities, Oklahoma Independent Petroleum Association, November 20145.

2. Operators should be given at least two years to replace their high-bleed pneumatic controllers. It will take that long for companies to plan accordingly, budget funds to support implementation costs, order and purchase equipment, and complete installation of the replacement equipment. Indeed, given the sudden and significant demand for new controllers that will be created by BLM's replacement requirement, it is highly likely that current supplies will not be adequate to meet the demand and that operators may face significant delays in obtaining the new equipment.

3. The Proposed Rule states that an operator may be exempted from the replacement requirement for a particular controller if it notifies BLM and BLM agrees that compliance with the replacement requirement "would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease."[58] This is the standard that was developed to justify an exemption from the flaring limits for all oil wells on a lease and is not appropriate for use here. Instead, it should be based on the cost of replacing a single pneumatic controller.

4. BLM substantially underestimates the cost of replacing pneumatic controllers in its proposed rule by keeping the focus of its analysis too narrow. The cost of this requirement is not limited to the cost of installing a new controller. There are significant labor costs as well as the costs of downtime and lost production during installation to consider. The Proposed Rule would also lead to a dramatic increase in demand for controllers, particularly given the short implementation window. This could potentially lead to difficulties for manufacturers' ability to meet the new demand, which would in turn drive prices of the device up. There are further downstream effects to consider too, as the increased requirements to capture and route gas will lead to additional demand for pneumatic controllers to manage those systems. This in turn will further drive demand (and therefore costs) higher.

[58] *Id.*

5. BLM should allow for use of high-bleed pneumatic controllers where they remain necessary for safety reasons. EPA makes such an allowance in its proposed NSPS OOOOa and we recommend that BLM do the same.

5. Replacing certain pneumatic pumps

The Proposed Rule would require operators to: 1) replace existing pneumatic chemical injection pumps and pneumatic diaphragm pumps with zero-emissions pumps, or 2) route the emissions from those pumps to a flare device on-site. BLM estimates that 8,775 pumps would be subject to the requirement. The requirement must be met within one year of the effective date of the rule. The requirement is objectionable for several reasons and should not be adopted.

If BLM chooses to adopt a replacement requirement in spite of the general objections noted above, then the requirement needs to be amended as set forth below.

1. The Proposed Rule requires replacement of all chemical injection or diaphragm pumps regardless of the amount of their actual emissions. If there is to be a replacement requirement, BLM should exempt pumps with *de minimis* emissions. Such pumps would include pumps that are: 1) not in constant service—i.e., operate less than 2,160 hours/yr; 2) portable; 3) routed to a process; or 4) whose emissions are less than 6 scfh.

2. The Proposed Rule states that a pump may be exempt from the replacement requirement if the gas that would normally be vented is routed to a flare device. However, flaring gas from pneumatic pump exhaust may not technically feasible in certain situations. Thus, many pumps subject to the rule will need to be replaced. BLM needs to reflect that fact in its cost-benefit analysis. BLM relies heavily on WDEQ's Upper Green River Basin (UGRB) Existing Source Rule pneumatic pump requirements to justify the proposed requirements in § 3179.202. BLM fails to acknowledge that such requirements were promulgated by WDEQ to regulate emissions in an ozone nonattainment area. It is unacceptable to apply a standard for a specific nonattainment area nationwide. It is also important to note that the UGRB is a unique basin that supports a multi-well pad approach to development. Because of this supported

development, it is easier for operators to route pneumatic pumps to combustion devices than it will be in other basins, nationwide.

Both in the UGRB and nationwide, not all pneumatic pumps can be effectively routed to an existing control device. Accordingly, operators will have to install a control device specific to pneumatic pump emissions. Take, for example, natural-gas fired piston pumps (i.e. pneumatic methanol injection pumps) located at the wellhead. Pneumatic methanol pumps at the wellhead are far from where existing combustors are typically located at a site (e.g. at the production equipment and /or storage vessels). As a result, there will be insufficient pressure from the exhaust of the pneumatic pumps to be routed back to the combustor. Operators will not be able to control emissions from these pumps with existing controls.

3. Operators should be given three years to comply with the replacement requirement. It will take that long for companies to plan accordingly, budget funds to support implementation costs, order and purchase equipment, and complete installation of the replacement equipment. Indeed, given the sudden and significant demand for new zero-emission pumps that will be created by BLM's replacement requirement, it is highly likely that current supplies will not be adequate to meet the demand and that operators may face significant delays in obtaining the new equipment. Operators may have hundreds of natural gas driven pneumatic pumps in each basin. One year is an insufficient amount of time to evaluate each pump, order and install replacement pumps or control devices and confirm proper operation. BLM relies on Wyoming's UGRB Existing Source Rule to justify the proposed requirements of § 3179.202 in the preamble. The UGRB Existing Source Rule was effective on June 30, 2015 and provided operators until January 1, 2017 to replace all pneumatic pumps with zero-emissions pumps, route such equipment to a line or closed loop system or route emissions to a control device. The UGRB Existing Source Rule covers a more sensitive area (i.e. an ozone nonattainment area) than BLM's nationwide rule and still provided a year and a half for compliance. A three year deadline to comply with § 3179.201 will give operators a more reasonable amount of time to ensure compliance. Increased compliance will decrease the "waste of natural gas" and conserve BLM inspection and enforcement resources upon final rule implementation.

4. The Proposed Rule states that an operator may be exempted from the replacement requirement for a particular well if it "provides an economic analysis that demonstrates, and BLM agrees, ... that installation of a zero-emissions pump would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease." As stated above, this standard is inappropriate. Instead, it should be based on the cost of replacing a single pneumatic pump.

6. Limiting venting from storage vessels

The Proposed Rule requires operators within six months to "route all tank vapor gas" that is vented from existing storage vessels that have "a rate of total VOC emissions equal to or greater than 6 tons per year" "to a combustion device or continuous flare, or to a sales line."[59] BLM estimates that the requirement "would affect about 300 existing storage vessels on BLM-administered land." The requirement is objectionable for several reasons and should not be adopted.

BLM's decision to use VOCs as a proxy for methane emissions is unreasonable. Generally, when crude oil has reached storage tanks it has undergone separation, where natural gas is removed from the product stream and diverted to sales. Although there will be some residual gas entrained in the crude oil, the vast majority of associated methane has been removed. Therefore BLM's calculations about the benefits of storage tank controls, which rely heavily on the social cost of methane (SCM), are inaccurate. BLM also underestimates the number of affected storage vessels in its analysis of the provisions. One single operator estimates that it will have approximately 100 storage vessels impacted by the proposed

If BLM chooses to adopt the requirements in spite of the general objections noted above, then the requirements needs to be amended as set forth below

1. The cost of controlling the vapors from existing storage vessels is much higher than for new storage vessels, and the life of an existing storage vessel is shorter. Therefore, the emissions

[59] *Id.* at 6685.

threshold for controlling the gas vapors from existing storage vessels should be higher than the 6 tons per year standard established by EPA for new storage vessels.

2. BLM has failed to consider the potential negative effects on climate change that may result from the control of tank vapors. The installation of combustion controls to reduce methane emissions from storage tanks may in fact increase the overall GHG emissions impact as a result of dramatically increased CO2 emissions. The example provided for a typical storage tank battery producing oil from the Bakken formation in North Dakota demonstrates that the installation of combustion controls increases the overall GHG impact by 228 percent. Considering that the Proposed Rule is a component of the President's White House strategy for climate change, it should clearly result in a net benefit in GHG emissions which BLM has failed to demonstrate.

3. Given all of the other requirements that would be placed on operators by the Proposed Rule, operators should be given at least one year to meet the routing requirement for storage tanks, and should be given six months to determine the rate of emissions from their storage vessels. Wyoming's UGRB Existing Source Rule was effective on June 30, 2015 and provided operators until January 1, 2017 to control or route to a sales line all applicable storage vessels. The UGRB Existing Source Rule covers a more sensitive area (i.e. an ozone nonattainment area) than BLM's nationwide rule and still provided a year and a half for compliance. In addition, BLM should clarify what is meant by a "new source of production." Is the rule intended to require an operator to determine the rate of emissions from a storage vessel whenever it receives production from a new well on the same lease as the well[s] from which it has previously received production?

4. The Propose Rule appears to blur the line between a storage vessel and a battery of storage vessels. EPA created some similar confusion in its 2012 NSPS OOOO rulemaking, which it later clarified in its "OOOO 1.75" amendments. NSPS OOOO provides that a "storage vessel affected facility" is an individual storage tank. BLM's Proposed Rule, however, defines a storage vessel as "a crude oil or condensate storage tank or battery of tanks that vents, or is designed to vent, to the atmosphere during normal operations." (emphasis added). The emission

control applicability threshold in BLM's Proposed Rule is defined by the PTE of a crude oil or condensate tank or a "battery of tanks," indicating that operators must determine applicability based on each tank's PTE and, where more than one tank is present, the sum of the PTE associated with multiple tanks in a battery. In light of BLM's definition of "storage vessel," BLM's proposed regulations for existing storage vessels is more stringent that EPA's control requirement for new and modified storage vessels. We strongly encourage BLM to maintain consistency with EPA and apply its storage vessel requirements to individual vessels, not storage vessel batteries.

Applying BLM's requirements to storage vessel batteries would dramatically increase the cost, complexity of requirements, and the number of vessels affected. Such a significant shift would likely necessitate BLM revisiting its cost benefit analysis here. One member reports having at least one basin with over one hundred applicable storage vessel facilities. With an estimated cost of $30,000 - $40,000 to purchase and install emission control equipment, the cost to comply with § 3179.203(c) appears overwhelming. Given this, it would appear BLM's estimate of 300 affected facilities is significantly understated.

A regulatory scheme, like the one BLM has proposed, that imposes more stringent requirements on existing tanks, which are a less significant source of emissions, than EPA imposes on new tanks makes no sense. We therefore urge BLM to forego the regulation of existing storage vessels. In the event BLM moves forward with its regulations, we recommend BLM revise the definition of storage vessel in § 3179.3 to read:

> a crude oil or condensate storage tank that vents, or is designed to vent, to the atmosphere during normal operations.

7. Limiting emissions from downhole well maintenance and liquids unloading

The Proposed Rule "would prohibit new wells from unloading liquids by simply purging the wells."[60] For both new and old wells, operators would be required to use "practices that maximize the recovery of gas for sale and must flare gas not recovered." BLM estimates that the requirements will impact 1,550 existing wells, as well as an undetermined number of other wells that are currently equipped with plunger lifts but not "smart" automation. The requirements are unreasonable and should not be adopted.

BLM bases its requirements on its belief that "[r]ecent technological developments allow liquids to be unloaded with minimal loss of gas," and that it is therefore "reasonable to expect operators to use these available technologies to minimize gas losses."[61] However, BLM's belief is at odds with tbe conclusion recently reached by EPA in its consideration of new source performance standards for VOC emissions from liquids unloading activities. After an exhaustive examination of the issue of emissions from liquids unloading, EPA concluded as follows:

> Data reviewed also show that liquids unloading events are highly variable and often well-specific. Furthermore, questions remain concerning the difficulty of effective control for those high-emitting events in many cases and concerning the applicability and limitations of specific control technologies such as plunger lift systems for supporting a new source performance standard.[62]

As a result of its analysis, EPA declined to regulate liquids unloading in its proposed NSPS OOOOa, as did the state of Colorado upon adoption of Regulation 7. The Colorado Department of Public Health and Environment (CDPHE) recognized that operators need flexibility to employ best management practices on a well-by-well basis.[63] CDPHE went on to recognize that automated plunger lifts are not pollution control devices and are not used in the field unless the

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[60] *Id. at* 6655.
[61] *Id.*
[62] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56593, 56645 (Sept. 18, 2015) (proposed rule).
[63] *Well Liquid Unloading Frequently Asked Questions.* CDPHE. August 17, 2015.

well design, geologic conditions, and gas content are appropriate for it. Given the significant difference of opinion between BLM and EPA on the feasibility of controlling emissions from liquids unloading, BLM should postpone adopting any liquids unloading requirements until that difference is resolved. The federal government should speak with one voice on this important issue.

We have serious concerns with the proposed liquids unloading requirements, particularly with the prohibition of well purging. The proposed Best Management Practices (BMPs) may not be adequate as a well declines, and later in its productive life, even a well classified as "new" under the Proposed Rule may need to be purged. Plunger lift systems are effective only to a point and do not serve as a panacea for well purging. Plunger lift systems will not be installed on all new gas wells at initial production. A plunger lift generally will not be used until the well has been on production for some time. At that point in time, if a plunger lift were installed at initial production, it would have to be replaced due to age. Differentiating between new and existing sources in this category is not logical as wells generally do not unload until later in life. We ask BLM to consider the following example:

Pipeline companies put back pressure valves on their pipelines. These are typically set at very low pressures in areas with low pressure gathering systems. The purpose of these valves is to protect the pipeline from surges in volume or pressure that in the opinion of the pipeline company might damage their line or metering equipment.

In these same areas, plunger lifts and intermitters are also often used. Intermitters are systems using pressure, or timer, controls that allow well pressure to build up in a well and then they open a control valve on the flow line based on a set time or pressure to allow the well to surge and flow at higher rate than the well could maintain on a continuous basis thereby carrying fluid to surface that would not be carried out if the well were flowing at the rate it can support on a continuous basis. Plunger lifts also use intermitters with the addition of a small plunger made of metal or a synthetic material that travels from a resting point on a stop in the tubing near the top of the wellbore perforations to the surface up the tubing. During each of these cycles, fluid and gas is pushed the hole and is pushed to the top of the tubing by well pressure. The plunger is

retained in the wellhead for a short period by pressure and flow. After a certain set period of time, or at a set pressure, the control valve on the flow line closes. After the valve closes, the pressure build-up cycle begins again. In the case of a plunger lift, the plunger drops back down the tubing to a spring loaded stop set in the tubing near the top of the perforations and it sits on the stop until the control valve on the flow line opens for the next cycle. In both cases, pressure builds and fluid that will be carried out of the hole enters the well during the shut-in period. Both of these are automatic unloading devices commonly used, and sometimes used in association with soap sticks and surfactants.

These pipeline backpressure valves cause problems with automatic unloading systems. When the well surges when an intermitter opens there is a higher initial pressure and gas rate with a duration of a few seconds to a few minutes. The volumes actually produced in the first minute would be small. The rate starts high but drops very quickly so the amount of gas flowing at the end of a minute may one quarter of the initial rate at the beginning of the plunger lift cycle or less. Very little gas is produced in the first minute or so of flow. Some of these systems cycle as few as one to three times per day. A more typical number of cycles might be eight to twelve times per day.

The increased gas rate and pressure at the start of a cycle would typically be inadequate in gas volume to make the sales line pressure up sufficiently to damage the line, even with poly line systems. However, the surge pressure causes the pipeline backpressure valve to shut in many cases because the valve just sees the pressure, it cannot detect the surge volume and associated pressure is inadequate to damage the line. Many of these valves have to be manually reopened. If one shuts it likely means a loss of production for 24 hours and sometimes more plus a fee to reopen them in some cases. Therefore operators in some areas use what is commonly known as a divert valve or "B Valve".

These diversion valves open at the beginning of a intermitter cycle and divert all or a portion of the gas flow depending on how they are designed into a tank, typically for a few seconds to less than a minute, although some may run longer. They bleed the surplus pressure and gas to a storage tank until the pressure drops enough to allow the gas to enter the pipeline

without tripping the pipelines backpressure protection valve. They can be controlled on a set time or pressure. After a certain time period or at a certain pressure the divert valve closes directing all the gas into the gathering line through the sales meter.

These systems are fairly common throughout low pressure gas and oil producing areas with low pressure gathering systems and they allow substantial natural gas, oil and condensate volumes to be economically produced when taken in aggregate over hundreds to thousands of wells in an area. They allow these reserves to be produced from formations where no other system would allow the economic production of these reserves. Their gas losses are minimal on a day-to-day basis and the operators are highly motivated to keep the diversion valves open only long enough to get the pressure low enough to get it into the line without causing the pipeline backpressure valve to shut, as they are losing revenue on every bit of gas going into the tank. The variety of these situations makes it difficult to suggest a simple requirement, which further underscores the inappropriateness of attempting to regulate liquids unloading.

These kind of systems result in minimal gas losses. We suggest an outright venting exemption from the regulations for plunger lift and intermitter systems using a divert valve unless the divert valve is found by BLM to not be closing at all, or in a reasonable period of time, and the operator fails to correct the problem within 5 days or notice being received from the BLM. Shutting the well in until repairs or adjustments could be made would be considered compliance with the 5 day rule.

The Proposed Rule also fails to describe the information collection expectations for subsequent unloading events by well purging at such wells. We would object to subsequent purging events leading to additional information collection requirements that aren't expressly state in the Proposed Rule. Requiring operators to document and notify BLM of all subsequent purging events will be unreasonable for operators and is unnecessary for the proper functioning of BLM. Well purging by liquids unloading is standard industry practice, with individual operators commonly reporting hundreds of liquids unloading events per year. Having to document and notify BLM of all purging events would be extremely burdensome for operators and would be unnecessary for the proper functioning of the BLM because operators are already

required to report unloading events under certain state programs (e.g., Wyoming) and pursuant to EPA's Greenhouse Gas Reporting Program. Furthermore, the deluge of notices BLM will receive if all purging events must be reported will overwhelm agency resources and prevent BLM staff from focusing on more important duties.

The Proposed Rule states that "[b]efore [an] operator purges a well for the first time after effective date of this section, the operator must document that other methods [of liquids unloading] are technically infeasible or unduly costly." This is an unreasonable requirement. As BLM notes, "operators must remove or 'unload' the liquids to maintain or restore production."[64] The rule should not require operators to immediately halt their maintenance or restoration efforts for an indefinite period of time while the feasibility and cost of other methods of liquids unloading besides purging are evaluate. Instead, operators should be given at least one year following the effective date of the rule before the documentation requirement must be met for any particular well. That will give operators adequate time to plan for the implementation of the requirement without bringing a halt to their ongoing maintenance or restoration efforts.

The Proposed Rule prohibits all "liquids unloading by well purging" for wells "drilled after the effective date" of the rule. Given the variety of factors from well to well and from field to field that may affect the technical feasibility and cost of using methods other than purging for liquids unloading, operators should be given the flexibility to employ best management practices in a fit-for-purpose manner based on the specific design, casing configuration, geology, and other factors. The state of Colorado acknowledged that need and BLM should as well. BLM's conclusion that "the alternative technologies discussed above [in 81 FR 6654-6655] now generally make well-purging unnecessary" is incorrect. Therefore, the prohibition on purging of new wells is infeasible.

The prohibition on purging will also require well swabbing or other maintenance operations. Swabbing is time-consuming, expensive, results in lost production due to well downtime, and still requires venting in the form of well blowdowns. Well blowdowns must occur before swabbing operations in order to depressurize the system and allow for safe working

[64] 81 Fed. Reg. at 6654.

conditions. The result is that BLM's prohibition on purging will not eliminate emissions from liquids unloading; it simply displaces them to another process while simultaneously adding cost that detrimentally impacts operators and royalty owners. This problem is further compounded because swabbing operations or similar maintenance may need to be done more frequently, again adding emissions and unnecessary costs.

8. Limiting emissions from well drilling and completions

The Proposed Rule would effectively prohibit the venting of any gas that reaches the surface during drilling and certain well completion operations. The gas must instead be captured and sold, flared, used in operations on the lease, or injected. These prohibitions are objectionable for several reasons.

1. Both sections 3127.101 and 102 require that gas that cannot be captured and sold or used in operations on the lease must either be flared or injected. As explained above, this preference for flaring (and injecting) over venting is not a "waste" prevention measure, as it does not prevent any "waste" of gas; instead, it is solely intended to reduce methane emissions out of a concern for the effect such emissions may have on climate change. The requirement that gas that is not captured and sold or used on the lease be flared or injected must therefore be deleted from the Proposed Rule. Moreover, as not all gas will be capable of being economically captured and sold or used on the lease, the Proposed Rule must state that gas that cannot be economically captured and sold or used on the lease may be vented.

2. Section 3179.101 effectively prohibits any venting of gas that reaches the surface during drilling. But achieving a no venting standard is not technically feasible in all circumstances, particularly when the gas reaches the surface through gas in solution, entrained gas or unplanned gas kicks. Gas in solution or entrained gas may be of insufficient volumes to burn continuously even after processing the drilling mud through a gas buster and sending the gas to flare. The gas will go to the flare but may not burn resulting in venting to the atmosphere. Gas from kicks in deeper formations goes to flare after separation in the gas buster but gas constituents such as high CO2 may prevent the gas from burning. Drillers must circulate

the gas out of the well to maintain control and venting is the only solution when gas quality is incombustible. Shallow gas kicks create unique circumstances. Shallow kicks occur when drilling surface hole without conventional BOP equipment. In areas of known shallow gas, a diverter with extended blooie lines is installed to prevent gas from accumulating under the rig in the event shallow gas is encountered. In general, it is not possible to shut in the well due to weak formations and controlling the influx requires diversion away from the rig as quickly as possible. The control method for shallow gas is to pump at the highest rate possible to raise the equivalent circulating density and control the influx. The high velocity mixture of gas, fluid and cuttings is not conducive to separation in a vessel to separate gas from the liquids and solids. The only safe solution is to vent to maintain control of the well.

3. Section 3179.102 effectively prohibits any venting of gas that reaches the surface during well completion and post-completion, drilling fluid recovery, or fracturing or refracturing fluid recovery. BLM should clarify, for fracturing and refracturing, that "gas reaching the surface" refers to the flowback following hydraulic fracturing and refracturing. Meeting a no venting standard is not technically feasible for flowback. Until a two or three phase separator can be operated, the only option for flowback is venting. Moreover, in fields with small volumes of associated gas like the Permian Basin, operators may be unable to run a two or three phase separator, and in fields that produce heavier crudes like Utah's Uinta Basin, operators may also not be able to run two or three phase separators. EPA's regulations allow venting from flowback until a gas/liquid separator can be operated so that sufficient gas can be captured and sent to a flare or put to beneficial use. BLM must allow venting in this circumstance as well.

4. BLM should also exempt wells with less than 300 scf per stock tank barrel of oil produced and wells with artificial lift equipment from the no venting standard, just as is done in EPA's regulations. We also encourage BLM to allow for pilot lights to be used on flares for drilling and completion operations in order to accommodate the variable quality and volume of associated gas that is produced during these processes.

5. BLM should not promulgate requirements for well completion operations following fracturing or refracturing as they duplicate EPA's NSPS Subpart OOOO and proposed OOOOa.

Subpart OOOOa will become applicable to each well completion with hydraulic fracturing or refracturing for all new gas wells and for all new oil wells with a GOR greater than 300 scf of gas per barrel of oil produced if NSPS OOOOa is promulgated as proposed. New wells are already covered by a specific NSPS, including requirements for emission controls, monitoring, recordkeeping and reporting. BLM will not benefit from any additional "waste" recovery by including their own well completion requirement.

6. EPA's OOOOa already includes recordkeeping and reporting requirements for compliance with the control requirements from flowback following hydraulic fracturing or refracturing. States have primacy to enforce NSPS regulations, and there are penalties for non-compliance. No additional compliance assurance will be achieved by requiring operators to submit a Sundry Notice to BLM stating compliance with NSPS OOOOa

9. Requiring the development of waste minimization plans

Section 3162.3-1 would require operators "[w]hen submitting an Application for Permit to Drill an oil well" to "also submit a plan to minimize waste of natural gas from that well."[65] In their plans, operators would be required to "set forth a strategy for how the operator[s] will comply with the requirements ... regarding control of waste from venting, flaring, and leaks and must explain how the operator[s] plan to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible."[66] Although the waste minimization plans would not be enforceable, "[f]ailure to submit a complete and adequate waste minimization plan [would be] grounds for denying or disapproving an Application for Permit to Drill."[67] The proposed requirement is objectionable for several reasons and must not be promulgated.

1. Requiring waste minimization plans is unnecessary – Requiring waste minimization plans is not necessary to achieve BLM's stated goal and is therefore not a "reasonable precaution" against "waste" of gas and is beyond BLM's authority to impose under the MLA.

[65] Waste Prevention, Production Subject to Royalties, and Resource Conservation,81 Fed. Reg. at 6679.
[66] *Id.*
[67] *Id.*

BLM "believes that requiring submission of a waste minimization plan would ensure that as an operator plans a new well, the operator has the information necessary to evaluate and plan for gas capture."[68] In other words, BLM is assuming that unless operators are required to gather certain information that they will need to comply with the venting and flaring limits, they will not do so. This is an insupportable assumption. Operators routinely conduct extensive planning about the current and future availability of infrastructure in their development plans for the express reason of minimizing flaring and maximizing gas capture.

Moreover, in order to comply with the venting and flaring limits, operators will of necessity have to plan how they will do so, even if there is no requirement to develop a waste minimization plan for submission to BLM. In other words, the existence of the limits themselves will motivate operators to plan; they will not need to be required to plan by BLM.

In addition, operators are fully capable of identifying what information will be needed to prepare their plans. Thus, having to generate and collect the information required by the Proposed Rule and then submit it in a prescribed format to BLM for review will serve no useful purpose. Preparing the plan for BLM will simply be a needless bureaucratic exercise that will waste the time and resources of operators in preparing the plan, as well as the time and resources of BLM in reviewing the plans to determine if they are "adequate and complete."

BLM states that the information required in waste minimization plans is comparable to the information that the North Dakota Industrial Commission ("NDIC") requires in gas capture plans. *See* 81 FR at 6642. However, the NDIC limits the amount of information that operators must provide from midstream companies with which they have no contractual relationship. For gas capture plans in North Dakota, operators simply relay information provided to them from the specific midstream company that is contracted to take that specific operator's gas. An operator must have a pre-existing contract with a gathering company in order for that company to take the operator's gas and to provide the operator the information requested by the NDIC. However, in the Proposed Rule, BLM seeks information operators do not have and may not be able to collect

[68] *Id.* at 6642.

because no contractual relationship exists, or are based on dedications that specific operators cannot use..

2. Requiring waste minimization plans for venting and leaks is unnecessary – The Proposed Rule would prohibit venting, except in specified circumstances, and would require the development and implementation of a Leak Detection and Repair Program. Thus, requiring waste minimization plans to address what will be done to minimize venting and leaks is not necessary since BLM is already prescribing what those actions are to be. BLM should clarify that waste minimization plans need address only how the operator intends to comply with the flaring limits in areas with known capacity issues.

3. Requiring waste minimization plans will further slow an already slow APD approval process – Waste minimization plans will not be enforceable, but a failure to submit an "adequate and complete" plan will be grounds for denying an APD. BLM will therefore have to review each plan before it can approve an APD, thus slowing down the APD approval process, which already often takes more than a year to complete. BLM should not assign itself a new task when it has demonstrated that it is not capable of performing the tasks it already has in a timely manner, nor should it assign itself a new task without establishing a deadline by which it is completed and without demonstrating that it will have the resources to meet that deadline.

Moreover, because it already takes so long to get an APD approved, the information in a waste minimization plan may well be stale by the time the APD is approved, and will thus serve no useful purpose. On average, it takes BLM three to six months to approve an APD on federal lands and 12 to 18 months to approve an APD on Indian lands. The difference with NDIC's gas capture plan is that the NDIC approves APDs within 15-45 days and meets with midstream companies on a regular basis.

By the time BLM approves an APD, most of the information BLM has requested will be out of date. Moreover, some information BLM is requesting in the waste minimization plans is not information an exploration and production company has at the time of submitting an APD. Examples of highly speculative and variable data include the anticipated daily capacity of the

pipeline at the anticipated date of first gas sales from the proposed well and the anticipated gas production rates of a proposed well. The waste minimization information collection requirement does not help exploration and production companies better prepare to comply with proposed flaring limits. It will only act to memorialize information that is outdated by the time the APD is approved by BLM or request information the operator cannot know. It is difficult to find any value in outdated and/or obsolete information supplied to BLM at the time of the federal APD submission. The requirement to create and submit waste minimization plan must be removed or drastically modified in the Proposed Rule.

4. Waste minimization plans should not be required to contain confidential and unnecessary information - The information that must be included in a plan pursuant to section 3162.3-1(j)(4)(i-iv and vi), (5)(ii-iv), and (6) is confidential business information and should not be required to be included in a plan. Moreover, the information that must be included in the plan pursuant to section 3162.3-1(j)(4)(i-iv and vi) is in the control of the pipeline companies. Thus, even if it were not confidential, operators would likely not be able to obtain the information. BLM should not demand confidential business information in the form of decline curve projections, price, forecasts, anticipated pressures, etc., particularly from publicly traded companies. Also, operators will not be able to share plans for expansion of pipeline capacity for the area that includes the proposed well, as anticipated in the Proposed Rule, unless the expansion has been publicly announced.[69] BLM has no utility for this information, and if there was any utility, it would not be operators who could provide it.

Some of the information that BLM would require in a waste minimization plan is not necessary to achieve the purpose of the plan, which is to "set forth a strategy for how the operator will comply" with the flaring limits. For example, to achieve that purpose, an operator does not need to identify for BLM "all existing gas pipelines within 20 miles of the well," and "the location and name of the operator of each gas pipeline within 20 miles of the proposed well;" it only needs to identify the pipeline to which it intends to connect. The Associations would argue that information about existing pipelines in an areas is, as a practical matter, irrelevant because BLM cannot force an operator's gas to be delivered to a nearby pipeline

[69] *See* § 3162.3-1(j)(4).

owned by a third party gas gatherer where there is no contractual relationship, except after a full hearing pursuant to 30 U.S.C. 185(r)..

5. Waste minimization plans should not be required for every new oil well – BLM should clarify that waste minimization plans only need to be prepared for new oil wells with associated gas on leases that do not already have an easily-accessible pipeline connection. Further, operators should be allowed to develop and submit plans that cover multiple wells, especially for multi-well pads that will utilize a common pipeline tie-in point.

6. Requiring an alternative on-site capture approaches is not necessary – Each waste minimization plan must "explain how the operator plans to capture associated gas upon the start of production."[70] That explanation will necessarily include an explanation of any "on-site capture approach" that the operator intends to use other than connecting to a pipeline. Thus, unless the operator is claiming that capture by pipeline or some on-site method is not economic, there is no need for the requirement in section 3162.3-1(j)(7) that the operator prepare an "evaluation of alternative on-site capture approaches."[71]

BLM has identified the areas where high rates of flaring are taking place, notably, in the Bakken and Permian basins. Given that many other areas with extensive federal minerals, such as Utah's Uinta Basin and California's San Joaquin Valley, do not have high levels of flaring, requiring waste minimization plans in those areas would be a pointless bureaucratic exercise. It is simply common sense that BLM should not require the expenditure of time and resources to prepare plans in area that do not have a problem with high levels of flaring.

10. Section 3179.10 – Other waste prevention measures

Section 3179.10 states that if gas capture is not yet available on a given lease, BLM may "exercise existing authority to delay action on the APD for that lease." The preamble cites 30 USC 187 and 225 as this existing authority. BLM's position is apparently that its authority to prevent "waste" allows BLM to indefinitely suspend action on an APD until gas capture

[70] *Id.* at 6679.
[71] *Id.*

infrastructure is available. Even assuming the statutory provisions for "waste" prevention extend to such an action, the Propose Rule would allow BLM to stifle exploration in frontier areas distant from gas gathering infrastructure. Although the Proposed Rule also allows BLM to suspend a non-producing lease while action on the APD is held in abeyance (authority BLM already has under 30 USC §209), the point is that BLM is creating a chicken and egg situation: gathering infrastructure will not be built in an area until there is a proven supply of gas to transport, and the existence of that gas cannot be shown until wells are drilled. In addition, §3179.10 seems to ignore Sec. 366 of the Energy Policy Act which requires BLM to issue the permit within 30 days after receipt of a complete APD "if the requirements under the National Environmental Policy Act of 1969 and other applicable law have been completed within such timeframe" or defer a decision and provide the applicant a notice that specifies any steps the applicant could take for the permit to be issued AND a list of actions that BLM needs to complete together with timelines and deadlines for completing such actions. In frontier areas, there will be nothing the applicant can do to make "gas capture capacity" available unless it is willing to bear the expense of installing electricity generation or gas liquidation facilities in advance of knowing whether the well will produce sufficient quantities of gas to power those facilities. A regulation that allows BLM to delay indefinitely the approval of an APD in areas where gathering infrastructure is not yet available could seriously diminish the value of leases covering lands in remote areas and work as a disincentive to test new geologic concepts.

B. Criteria for determining when flared gas is "waste"

Section 3179.4 is intended to clarify the definition of what constitutes "unavoidable loss" of gas from flaring by, among other things, "listing specific operations and sources that produce gas that BLM would deem 'unavoidably lost,' as long as the operator has not been negligent, has not violated laws, regulations, lease terms or orders, and has taken prudent and reasonable steps to avoid waste."[72] The list needs to be expanded, as explained below.

1. The definition of "unavoidably lost" should include gas gathering force majeure events, which disrupt gas take-away capacity, and should not be subject to the 24 hour duration limit applicable to emergencies. Venting and flaring during a force majeure event should also

[72] *Id.* at 6665.

not be royalty bearing (3179.5) and should be excluded from flare limit calculations (3179.6) and measurement requirements (3179.8).

Volumes flared as a result of a force majeure event are unavoidably lost under NTL-4A Section II.C.(2) ("'Unavoidably lost' production shall mean...(2) that oil or gas which is lost because of line failures, equipment malfunctions, blowouts, fires, or otherwise..."). During a force majeure event, a well may continue to sell at its full rate or at a reduced rate, depending on whether the gatherer is flaring gas at the pipeline outlet and depending on how much line pack volume (spare capacity) is available before the pipeline reaches maximum allowable operating pressure (MAOP).

Once connected to a gas sales pipeline, all flaring due to "compressor or other equipment failures, relief of abnormal system pressures, or other conditions which result in the unavoidable short-term venting or flaring of gas" is authorized under NTL 4A Section III.A as an "Emergency" without incurring a royalty obligation. Gas is frequently flared in North Dakota when the line capacity or compression capacity is reached because allowing those volumes to flow (such as by increasing the separator pressure), creates the potential to exceed pipeline MAOP and risk line failure.

In addition, the State of North Dakota flaring regulations provide exceptions to the flaring limits for flaring that result from force majeure events.[73] The North Dakota requirements have achieved the goal of reducing flaring in the state while still providing critical flexibility that allows for continued operations without penalties during a force majeure event.

Thus, the Proposed Rule is inconsistent with the existing flaring regulations in North Dakota and the BLM's own existing regulations under NTL-4A, both of which provide essential exceptions for force majeure events. Because a force majeure event is, by its very nature, unforeseen and beyond an operator's control, all flaring during a force majeure event should

[73] *See* North Dakota Industrial Commission, North Dakota Industrial Commission Order 24665 Policy/Guidance, , available at https://www.dmr.nd.gov/oilgas/GuidancePolicyNorthDakotaIndustrialCommissionorder24665.pdf, stating that "[t]he operator is allowed to remove from the total monthly volume calculation gas volumes flared from wells already drilled and completed on the date a force majeure event occurs if the event is properly documented in writing by the gas gathering company."

constitute "unavoidably lost" gas under the proposed rule, should not contribute to any volume limitation, and should not require metering. BLM could simplify the rule by simply considering any gas flared from a well that is connected to a pipeline as being unavoidably lost. Obviously, once an operator has connected a well to a pipeline, it has every incentive to maximize the revenue from that investment. Any disruptions are going to be the result of operational events beyond the operator's control, such as those related to capacity issues.

2. Consistent with NTL-4A, losses from "low-pressure production vessels" (such as heater treaters, which function as secondary separation), should be considered "unavoidably lost" (3179.4), should not be royalty bearing (3179.5), and should be excluded from flare limit calculations (3179.6) and measurement requirements (3179.8).

Low-pressure production vessels typically include secondary (tertiary, etc.) separation equipment, wherein gas is recovered at pressures below the gathering pipeline operating pressure and wherein the gas volume contribution is too low to reasonably make sales without significant operating and/or capital expense.

For example, traditional facility setups in the Bakken include a first stage two phase separator, which separates the majority of gas from the combined liquid stream. It is followed by a three phase heater treater, which separates water from oil as well as any gas remaining with the liquid stream that is recoverable at the equipment's specific operating conditions. The standard practice is to operate the inlet separator at or slightly above (to account for line loss pressure drop between the separator and sales meter) the MAOP of the gas sales line. Thus as long as the pipeline has not reached its MAOP, all separator gas will sell.

The treater typically operates at least 15 psig less than the separator to allow liquids to dump via pressure between the two vessels. The treater's maximum allowable working pressure is typically 75 psig, which is less than typical sales line MAOP in the Bakken. Because this vessel operates at a very low pressure, closer to 30-50 psig, treater gas cannot normally enter the sales line and any treater gas vented or flared from this low-pressure vessel should constitute an "unavoidable loss" consistent with NTL-4A Section II.C.(1) ("'Unavoidably Lost' production

shall mean (1) those gas vapors which are released from storage tanks or other *low-pressure production vessels...*") (emphasis added). This exception in NTL-4A for low-pressure vessels reflects operational realities and must be included in the Rule. Note that the language of NTL-4A expressly provides a separate exemption for low pressure production vessels in addition to storage tanks. Per ASME Boiler & Pressure Vessel Code VIII, a "pressure vessel" is defined relative to a tank as operating above 15 psi, thus a Treater constitutes a "low-pressure production vessel."

Furthermore, to comply with NDIC Order #25417 (the "Oil Conditioning Order"), companies must operate treaters at or below 50 psig, which will ensure these treater gas volumes must go to flare rather than to sales based on typical gathering line pressures. Consequently, the proposed rule directly conflicts with existing North Dakota requirements, and it would be infeasible (if not impossible) to comply with both rules simultaneously.

Field measurements at a sample of sites across the Bakken where the separators and the treaters are equipped with allocation gas meters show that treater gas makes up approximately 3% or more of total, non-tank vapor gas on average for typical pressure conditions. Due to the relatively low volume of gas from the treater, it is infeasible, uneconomic and unnecessary to install pad compression or a vapor recovery unit to capture this low pressure gas. Again, NTL-4A reflects operational realities that the proposed rule fails to consider.

3. It is not feasible to add a redundant gathering system, especially with a dedicated gas contract in place. BLM has grossly underestimated the time, effort and cost to capture incremental volumes in a constrained system like the Bakken. The Rule must account for the economics specific to the well and region in question.

BLM's premise in the preamble, RIA, and Proposed Rule itself is that additional permanent infrastructure can be built to capture the incremental flare volumes where capacity is constrained or remote capture technology can be deployed to individual well sites where permanent infrastructure is undersized or infeasible. The RIA incorrectly asserts that in times of downturn and reduced activity due to low commodity prices, gathering companies can "catch

up." However, the exact opposite is true. When commodity prices are low, it also impacts the gas gatherers, making additional capital investment difficult and less likely.

Under NTL 4A, BLM may approve venting or flaring of oil well gas without incurring a royalty obligation based on engineering, geologic, economic, and recoverable reserves information. A narrower set of standards for existing wells is specified in Section 3179.7(a)-(c) of the new rule. In connection with a recent appeal to the BLM State Director of a BLM North Dakota Field Office Decision Record regarding the Field Office's proposed plan for processing flaring sundry notices, the State Director issued a decision ("State Director Decision") concluding, among other things, that the costs and economics of gas capture must be considered in making an "avoidably lost" or "unavoidably lost" determination.[74] BLM must revise the "unavoidably lost" definition to include gas flared once connected to a gas pipeline. However, if such a definition change is not made, section 3179.7 should be simplified to expedite the approval process and modified to apply to both existing and new pads with gas pipeline connections.

Gas pipelines require long term planning and investment, including lengthy ROW and permitting processes, particularly on tribal land. Often the slowest permits are related to the BIA, USFS, and BLM jurisdictions, and the State Director Decision recognizes these ROW challenges and deems all flaring while a ROW is pending to constitute "unavoidable loss". In addition, the "North Dakota Industrial Commission Order 24665 Policy/Guidance" document issued by the NDIC expressly provides for temporary exemptions for ROW delays. The local BLM authority in the Bakken and the State both recognize that flexibility is required for ROW delays. This concept is absent from the Proposed Rule and needs to be included.

Midstream companies gather gas from many pads from many operators under dedications because production from multiple locations is necessary to invest in the infrastructure, especially with rapid decline rates such as in the Bakken. It would be difficult and uneconomic for any single operator to pay for a dedicated gas pipeline and processing system with a few wells that

[74] *See* SDR No. 922-15-07 issued February 11, 2016 by Aden L. Seidlitz, Acting State Director, at 9, 10, 12.

quickly decline to low volumes. To support infrastructure investment, gas gatherers require commitments from producers to ensure gas will flow through their infrastructure. These commitments vary by agreement and market but almost universally limit alternate gathering options. Furthermore, most dedicated contractual obligations make it difficult to bring a long-term secondary gathering system to the same pad location. If such a secondary agreement were allowed, it would only be allowed on an interruptible basis and would only be used sporadically, thereby making a secondary system even more uneconomic and infeasible.

Gas gatherer economics (a full discussion of which is beyond the scope of these comments) are heavily dependent on capturing volumes because most gas gathering agreements charge per unit of gas transported across the system. Gas gathering systems rely on pad-specific infrastructure that typically consists of a pipeline and measurement equipment that connects the pad to a commingled system of lower pressure trunklines, compressors, and higher pressure discharge lines to efficiently move the gas from the pad to a treating and/or processing facility to make the gas and associated liquids (if any) marketable to the downstream markets. Early production in a well's life is critical for the gas gatherer to recoup the investment for the pad-specific infrastructure. Any operation mode (e.g. automatic shut-ins or waiting until infrastructure "catches up") that risks flattening the decline curve by capping production could be expected to jeopardize gas gatherer economics and further hinder infrastructure investment.

Building a separate gathering system for each operator would not only be economically prohibitive, but it would also be redundant and require multiple ROWs in the same area and across the same landowner property. Repeated ROW requests increase surface use and have led historically to landowners unreasonably or intentionally blocking easements and demanding exorbitant compensation from operators.[75] A redundant plant and the necessary compressor stations further lead to increased surface use.

Any backup gas gathering infrastructure must be completely redundant and would require a cost burden of approximately 10 times the market value of the recovered gas, assuming gas

[75] The North Dakota Industrial Commission recognizes the difficulty in obtaining rights-of-way and specifically allows temporary exemptions for right-of-way delays.

volumes available for redundant sales of approximately 20%, based on current Bakken flare percentages. Lessees cannot afford this undue burden.

4. BLM should consider flaring associated with pigging activities "unavoidably lost."

Due to the high liquid content of the gas in some areas, the gas gatherers must frequently pig their lines, sometimes multiple times in the same day, to manage liquid buildup. Pigging essentially involves launching a malleable or hard plug (called a pig) from an upstream location and allowing pressure to carry the pig to a receiver. The pig sweeps liquid forward and thus reduces liquid in the line. As the pig and liquid front sweep through the system, pressure increases upstream and can thus reduce sales volumes.

Pigging is generally not considered a force majeure event, but it can cause operational outages similar to a force majeure event. Furthermore, during pigging operations, it is undesirable to completely shut-in upstream wells as the drive mechanism for the pig will be lost and the likelihood of a stuck pig scenario will be increased, which would only exacerbate flaring or keep wells shut-in longer.

Flaring during pigging operations should be considered "unavoidable". Given the frequency of pigging, it is infeasible and unduly burdensome for the gatherer to document and provide notice of all pigging events. Therefore, proper gathering line operation and pigging further justify that all flaring from wells connected to pipeline constitutes "unavoidably lost" gas without necessity of BLM approval.

5. It is not a given that associated gas produced from a well will be of sufficient quality to be marketed, and in some instances the cost of processing gas to bring it to pipeline specification may exceed the value of the recovered product. We urge BLM to consider exempting gas based on the presence of CO2, Oxygen, Nitrogen, H2S, and other impurities.

C. Royalty rates for newly-issued competitive leases

1. The process for raising the royalty rate above 12.5%

In accordance with the MLA, the Propose Rule would authorize BLM to set the royalty rate on competitive leases issued after the effective date of the rule at not less than 12.5%. BLM states that it "does not currently anticipate increasing the base royalty rate for new competitively issued leases above 12.5 percent," and that "[b]efore making such a change, the BLM would announce the change prior to the effective date, and would provide for a public comment period."[76] It also lists some of the "relevant factors" that it would "potentially" take into account in any decision to raise the royalty rate. BLM requests comment on "the adequacy of the public process [it] outlined."

As was made clear in the numerous responses that BLM received in response to its Advanced Notice of Proposed Rulemaking on the subject of raising royalty rates,[77] any decision to do so would be highly significant to a wide variety of stakeholders, and should be informed by a wide variety of considerations. The public process for making such a decision should not therefore be based on BLM's non-binding statements in the preamble to the Proposed Rule; it should be set forth in the rule itself. Indeed, even if the public process were not set forth in the rule, a decision to raise the royalty rate would be a "rule" as defined by the Administrative Procedures Act,[78] and therefore could not be made except in compliance with the notice and comment requirements of that Act. Moreover, the Proposed Rule should state that royalty rates will not be raised on existing leases.

The Proposed Rule should identify the specific factors BLM shall consider in making a decision to raise the royalty rate in advance of any leases to which the increase rate would apply (including, at a minimum, the factors it identified in the preamble to the Rule), and should state that: 1) BLM will give public notice of its intent to raise the royalty rate at least one year in

[76] 81 Fed. Reg. at 6660.
[77] Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments, 80 Fed. Reg. 22,148 (Apr. 21, 2015) (advance notice of proposed rulemaking).
[78] 5 U.S.C. § 551(4).

advance of doing so; 2) the notice will include a full explanation of BLM's reasons for believing that a royalty rate increase is needed; 3) the public will be given at least 90 days to comment on the notice; and 4) BLM will respond in writing to the comments it receives before issuing its decision.

Moreover, even though BLM states that it "does not currently anticipate increasing the base royalty rate for new competitively issued lease above 12.5%," it is important to remind BLM that increasing the royalty rate above 12.5% would almost certainly have negative impact on oil and gas production on federal lands. John Dunham & Associates, an economic consultancy, has modeled the impact on federal production under twenty-four scenarios involving varying degrees of change to royalty rates and rental rates on federal leases.[79] Net expected production was calculated at a base royalty rate of 12.5%, and potential increases to 14.75%, 16.75%, 17.75%, and 18.75% with corresponding rental rates of the current $1.50/$2.00 per acre, $2.00 per acre, $3.00 per acre, $4.00 per acre, and $5.00 per acre. Under every scenario, raising royalty rates and rental rates had a negative impact on federal oil and natural gas production. The net result of that lost production is a reduction in federal energy revenues of up to about $51 million.[80]

While federal royalty rates are presently lower than royalty rates in some states,[81] there are good reasons why royalties on federal leaseholds are lower. For federal leases to be attractive to operators compared to leases on state and private lands, the federal lease rate must account for the time and expense involved in obtaining the lease, complying with overlapping state and federal regulations, performing the requisite environmental review required under federal law, and the difficulty involved with accessing federal lands. Our members' experience reveals that the overall cost of developing leases on federal and Indian lands is consistently higher than for similar projects on state and fee lands. While it is reasonable for BLM to attempt to set royalty

[79] Dunham & Associates' full report describing the modeling efforts and conclusions is attached as Exhibit A to these comments.
[80] *See* Ex. A at 1. It must be noted that the model used for this analysis only assesses development in thirteen western states: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Some states with meaningful activity on federal lands, particularly California and Alaska, are not included in the model. As a result, the model likely underestimates the value of lost revenue attributable to higher royalty rates and lease fees.
[81] *See id.* at 3, Table 2.

rates at values that maximize the federal government's return on federal leases, the marketplace sets a limit on how high rates can be before federal leases become an unattractive asset.

Higher royalty rates and associated lease fees impact federal oil and natural gas production in at least two ways: (i) higher costs make marginal projects uneconomical;[82] and (ii) higher costs increase the risk premium that oil and natural gas producers will require before bidding on leases.[83] The extent of the impact on production is likely to vary based on a host of geologic and economic factors. Under current production costs and economic conditions, for example, royalty rate changes may have little impact on projects focused on natural gas because commodity prices make new development uneconomic under any royalty scenario. In legacy oil fields, however, where many drilling permits are issued and the drilling of inexpensive vertical wells is common, the impact of increasing royalties and associated leasing fees is much more significant.

Nor are losses limited to lost royalty revenue. The oil and natural gas industry currently generates more than 173,000 direct jobs (not including additional secondary jobs) in the thirteen states the model analyzes. Depending on which of the twenty-four scenarios examined is ultimately adopted, as many as 1,330 direct jobs could be lost in these states alone. And because workers in the oil and natural gas sector tend to be highly compensated relative to workers in other economic sectors, job losses in oil and natural gas development disproportionately impact overall economic activity.[84]

Under the modeled scenarios, the loss of direct revenue to the federal government from oil and natural gas leasing resulting from a reduction in wells developed due to increased royalty rates and lease fees could be as much as $37 million annually. This represents meaningful losses

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[82] Higher costs also mean that projects that are not presently economic are even less likely to occur in the future because more significant economic change is necessary before those projects can become economic. At least one federal agency has concluded that the development of marginally economic projects is already deterred because of the federal government's "regressive fiscal regime." Irena Agalliu, U.S. Dep't. of the Interior, Bureau of Ocean Energy Management, Comparative Assessment of the Fed. Oil & Gas Fiscal System . 5 n.5 (2011), http://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Fair-Market-Value/CERA-Final-Report.aspx. Higher royalty rates and lease costs would further exacerbate this existing problem.

[83] One strategy that operators are likely to employ to achieve this risk premium is offering lower bonus bids when bidding on federal leases. *See* discussion *infra* Part II.C.

[84] Ex. A at 10-11.

to the federal government, but also to the states that receive fifty percent of all monies from oil and natural gas production on federal lands within a state's borders.[85] But losses are not limited to the revenues from wells that are not drilled. Federal, state and local governments also stand to lose business, property and personal tax revenue from companies and individuals in the oil and natural gas activity, as well as the benefits of economic activity associated with full employment in the oil and natural gas industry. Modeling results suggest that these losses could well exceed $13.8 million for the federal government alone.

2. Fluctuating royalty rates

Although it has not been formally proposed, BLM states that it is "considering a provision that would allow royalty rates on new competitively issued leases to vary after the first year, based on the lease holder's record of routine flaring of associated gas from the lease during the previous year."[86] The purpose of the provision, which BLM refers to as a "royalty adder provision," would be: "(1) To create an incentive for bidders to consider the availability of gas capture infrastructure and the proximity of gas processing facilities as attributes that add significant value to Federal oil development leases; and (2) To create an incentive for Federal lease holders to plan for gas capture prior to or in conjunction with the development of oil wells."[87] Such a provision would be both an abuse of the Secretary's discretion and inconsistent with the Rule, and should not be given any further consideration by BLM.

The MLA gives the Secretary the discretion to set the royalty rate for competitive leases, as long as the rate is not less than 12.5%. The Secretary is to use her discretion to set the rate at a level that will insure a fair return to the government for the use of public resources. It would be an abuse of that discretion for the Secretary to use her authority instead to promote her policy to reduce flaring.

The adder provision would also be inconsistent with the Proposed Rule. Under the Proposed Rule, BLM is telling operators of new leases that flaring done in compliance with the

[85] *See* 30 U.S.C. § 191(a).
[86] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. at 6660.
[87] *Id.*

1,800 Mcf/month flaring limit will not be considered a "waste" of gas, and will therefore not be subject to a royalty. Under the adder provision, however, BLM would be telling those same operators that unless they flare at a significantly lower rate, "the threshold flaring rate", they will have to pay additional royalty. BLM gives no adequate explanation for this disconnect; it justifies the adder provision solely in terms of its ability to incentivize lease holders to plan ahead for gas capture. But the flaring limit in the rule and the requirement that operators develop waste minimization plans were supposed to provide that incentive. It would be arbitrary to say that flaring in compliance with the rule's 1,800 Mcf/month limit is not a "waste" of gas, and to then turn around and say that compliance with anything less than the adder provision limit would be a "waste" of gas, and would subject operators to a royalty increase.

We endorse the comments submitted to OMB by the Council of Petroleum Accountants Societies on this subject. They demonstrate the impracticability of this provision from an accounting perspective.

D. State or Tribal Variances

As detailed in the preamble, states, tribes, and EPA all have programs that deal in one way or another with the venting and flaring issue. It is thus extremely important that the Proposed Rule contain a variance provision that is workable and that will give timely relief to operators from duplicative or conflicting requirements. We would prefer a general deferral to existing state and tribal programs, but the variance provision offers at least the possibility of eliminating overlapping and duplicative requirements as a means of reducing administrative costs and improving efficiencies. If BLM is unwilling to defer to existing State and tribal programs, the following changes should be made in section 3179.401. Also, a variance provision should be added to the section 3160 to allow for a State to request a variance from the waste minimization plans.

1. The section should state that the request for a variance automatically tolls any deadline for compliance with the federal requirement from which a variance is being sought. Failure to

provide such a provision will make the provision for a variance practically meaningless, as operators will be left in regulatory limbo.

2. The section should state that any request for a variance that is not approved by the BLM State Director within 60 days of its submission shall be deemed approved. This will insure that the variance provision does not become a bottleneck that leaves operators uncertain for indefinite periods of time about the requirements that will apply to them.

3. The provision states that BLM "reserves the right to rescind a variance or modify any condition of approval." This unfettered discretion which allows BLM to revoke a variance for any reasons or no reason at all is clearly unreasonable and should not be part of the Proposed Rule. It will put the plans and investments of operators at continual risk, as operators will always have to reckon with the possibility that BLM will arbitrarily revoke a variance on which they have based their operational and investment decisions.

4. The section should state that States and tribes may appeal any denial of a request for variance or any revocation or modification of a variance. Without the right to appeal BLM's decisions, there is no protection against a completely arbitrary denial or revocation of a variance. Indeed, without a right to appeal, and hold BLM accountable for its decisions, the right to request a variance is of little practical value.

Conclusion

In closing, we reiterate the tremendous progress that America's oil and natural gas industry has made, and will continue to make, in addressing issues associated with venting, flaring, and methane emissions. However, after a careful examination of the Proposed Rule, we have concluded that it is arbitrary and in excess of BLM's authority and should not be promulgated. If BLM nonetheless proceeds with the rule, it needs to be substantially re-written to make it workable for industry and BLM, consistent with the many recommendations that we have made above. At a minimum, BLM should suspend work on the Proposed Rule until it is clear how EPA will regulate air emissions from existing oil and gas sources. This would be

consistent with BLM's policy of avoiding duplicative or conflicting federal mandates. In the meantime, we would request that BLM direct its resources toward the timely processing of ROW applications, as that would have a much greater impact upon the reduction of flaring than the Proposed Rule.

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APPENDIX A

JOHNDUNHAM &ASSOCIATES
The Winning Side of Economics

MEMORANDUM

TO:	Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM:	Mike Stojsavljevich
DATE:	April 12, 2016
RE:	Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR 3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)

Executive Summary:

As per your request John Dunham and Associates (JDA) has reviewed *Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)*, which was produced by the Bureau of Land Management (BLM) in January 2016.[1]

This analysis of the proposed rules estimates the costs far exceeding the benefits. The proposed rules are estimated by the BLM give a high end cost of between $117 - $174 million (assuming either a 3 percent or 7 percent discount rate, Environmental Protection Agency (EPA) finalizing or not finalization of Subpart OOOOa, and various methane reduction assumptions).[2]

JDA estimates that the costs exceed $1.26 billion, while the benefits as estimated by the BLM are between $115 - $384 million (assuming either a 3 percent or 7 percent discount rate, EPA finalizing or not finalizing of Subpart OOOOa, and various methane reduction assumptions).[3] A more reasonable estimate of the benefits suggest that they are at best $90 million[4], hence the cost-benefit ratio of the proposed rules is nearly 14:1 cost to benefit.

The $1.26 billion cost of the proposed rule to the industry is best examined in three primary components. First, based on the costs of implementation outlined in the RIA prepared by the BLM, JDA estimates an economic impact on jobs, wages, and lost output of $997,199,000. Additionally, those economic losses create an additional loss of $114,112,000 in federal and state taxes. Finally, a conservative estimate suggests a total of $174 million in costs associated with implementing the rule.[5] This can be viewed as an annual incremental cost to the industry.[6]

Additionally, a reduction in oil well development from the proposed rules will leave 112.4 million barrels of developable oil in the ground.[7] This undeveloped oil is best viewed as oil that is shut-in due to the regulatory burden of implementing the proposed BLM rules.

Also, the BLM claims benefits of about $23 million in Federal royalties and 16.5 million metric tons of carbon dioxide equivalent emissions. This reasoning does not reflect the current state of the market. JDA estimates that the $23 million dollar figure presented by the BLM would drop to $3.68 million or possibly

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1 U.S. Bureau of Land Management, *Regulatory Impact Analysis for: Revisions to 43 CFR 3100(Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and gas Operations)*, at: www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.11216.File.dat/VF%20Regulatory%20Impact%20Analysis.pdf

2 Ibid., pages 6-8.

3 Ibid., pages 6-8.

4 Based on JDA estimates

5 Cost estimates rise to $319 million if all rules are implemented, EPA does not finalize Subpart OOOOa, and there are no methane offsets, which we detail below.

6 The economic impact of $1.26 billion is based on $997 million in economic impact, $114 million in lost taxes and $174 million in costs to the industry, which is our low end estimate based on BLM's RIA. JDA's internal cost estimates rise to $319 million and could increase the total economic impact to $1.43 billion.

7 Based on internal JDA estimates

considerably less, even approaching $0 when examining the current pricing environment and understanding the super-cyclical nature of the current oil and gas industry where inventory builds may create a situation where there is no additional demand for oil or gas

Background

This analysis also examines the claims and procedures of the regulatory impacts done by the Bureau of Land Management (BLM) and their proposed rulemaking, which would update 43 CFR Part 3100 (Onshore Oil and Gas Leasing) and 43 CFR Part 3160 (Onshore Oil and Gas Operations) and propose new regulations 43 CFR Chapter II, Subpart 3178 (Royalty-Free Use of Lease Production) and Subpart 3179 (Waste Prevention and Resource Conservation). The proposed Subparts 3178 and 3179 would update and replace the BLM's current policy document Notice to Lessees-4A (or "NTL-4A").

The BLM rule claims to have five specific goals:

1) Modify the requirements that limit the venting and flaring of produced natural gas. The proposed rule would prohibit venting of gas except in certain circumstances, and would limit gas flaring during normal production operations from development oil wells to 7,200 Mcf/month (on average, per well, across all of the producing wells on a lease) for the first year of the rule's implementation, 3,600 Mcf/month/well for the second year of the rule's implementation, and 1,800 Mcf/month/well thereafter. Gas flared from a well that is connected to infrastructure would be royalty-bearing except in certain narrow circumstances, such as emergencies.

2) Limit losses of gas through venting and leaks by placing requirements on other activities and equipment, including well drilling, completions and workovers, production testing, pneumatic controllers and pumps, storage tanks, liquids unloading, and leak detection and repair (LDAR). As a practical matter, many of the proposed requirements would impact only existing equipment or facilities that are not regulated by the EPA's existing New Source Performance Standards (NSPS) Subpart OOOO (nor by the EPA's recently proposed Subpart OOOOa, if that rule is finalized).

3) Conform the BLM's royalty rate provisions for competitive oil and gas leases to the corresponding statutory text, which prescribes a rate "not less than" 12.5 percent.

4) Require the operator to submit additional information to the BLM with its Application for Permit to Drill (APD) for a new oil well. Specifically, the operator must submit its plan to minimize the waste of natural gas from the planned well to the degree reasonably possible.

5) Clarify the parameters for an operator to use production on lease without paying royalties on that production. The changes would ensure that the royalty free use of production applies only to uses on the lease, unit, or CA. The changes would not prohibit the operator from using the production off the lease, unit, or CA, but those uses would incur royalties.

Conduct of a Regulatory Impact Analysis:

As part of the rulemaking process, all Federal regulatory agencies are required to conduct a Regulatory Impact Analysis (RIA). While these analyses are designed to determine if a proposed regulation will have a reasonable effect on the environment while not costing society substantial resources, they are also designed to determine if there are other alternative measures that the regulatory agency should take rather than proposing new rules. Unfortunately, the Bureau of Land Management (BLM), which developed this RIA has built a case for this regulatory endeavor by using outdated data sources and this flawed data and methodology have led to flawed conclusions.

The BLM performed an impact analysis for individual rulemakings under the Act's authority. The analysis must contain an analysis of each of the following impacts:

- The costs of compliance,
- Any potential inflationary or recessionary effects,
- Effects on competition with respect to small businesses,
- Effects on consumer costs, and
- Effects on energy use.[8]

This is not a true regulatory impact analysis but rather a general accounting based on outdated data sources of the direct costs of the proposed regulation. More importantly, two long-standing Presidential Executive Orders require all agencies, including the BLM, to conduct an analysis of the benefits and costs of a proposed significant regulatory action, including a comparison of the benefits and costs of alternative regulatory approaches.[9] Executive Order 12866 requires that all regulatory actions be reviewed by the Office of Management and Budget (OMB) and gave the Office broad powers to review and request revisions to all regulatory proposals.

This same Executive Order requires that an agency, including BLM, "Shall ... propose or adopt a regulation only upon reasoned determination that the benefits of the intended regulation justify (emphasis added) its costs."[10]

The Requirements of an RIA:

According to the Office of Management and Budget (OMB), there are 16 key elements that every Regulatory Impact Analysis (RIA) needs to address.[11] The OMB even provides agencies with a detailed primer on how to conduct an RIA in accordance with its guidelines and the underlying Executive Orders.[12] Additional requirements from the various laws governing RIAs such as the Unfunded Mandates Reform Act and the Regulatory Flexibility Act also need to be met by the BLM.

The OMB suggests that each agency include are:

1. A reasonably detailed description of the need for the regulatory action;
2. An explanation of how the proposed regulatory action will meet that need;
3. An appropriate baseline assessment of how the world would look in the absence of the proposed action;
4. An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action;
5. An explanation of why the planned regulatory action is preferable to the potential alternatives;
6. An uncertainty analysis;
7. A description and discussion of the distributive impacts of the potential alternatives;
8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action;
9. A clear and transparent table presenting anticipated benefits and costs.

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8 *Economic impact assessment*, United States Code, Title 42, Chapter 85, Subchapter III, Sec. 7617, at: http://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapIII-sec7617.htm

9 Federal Register, Vol. 58, No. 190, *Executive Order 12866 of September 30, 1993*, Monday, October 4, 1993, at: https://www.archives.gov/federal-register/executive-orders/pdf/12866.pdf

10 Ibid.

11 Office of Management and Budget, *Agency Checklist: Regulatory Impact Analysis*, www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/RIA_Checklist.pdf.

12 Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, at: www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf.

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner;
11. Provide the data, sources and methods used in the RIA to the public via the internet;
12. Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible;
13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible;
14. Explain and support how the benefits of the intended regulation justify its costs;
15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach;
16. Use appropriate discount rates for benefits and costs expected to occur in the future.

In addition to these 16 items, a proper RIA must examine a number of additional impacts including international effects and the effects on small businesses.

Very few RIAs ever fully follow the OMB guidelines, even though they represent best practices for this sort of analysis. This is definitely the case with the RIA performed by the BLM staff for this proposed rule. Not only does the RIA fail to perform 10 of the 16 checklist items, the analysis presented is biased, and uses many flawed assumptions.

Critique of the Analysis Prepared by the BLM:

This critique examines each of the items suggested by the OMB and outlines particular issues with how the BLM performed this particular study.

1. A reasonably detailed description of the need for the regulatory action: **The RIA does document a need for regulatory action on the part of the BLM.** According to the RIA, a large amount of natural gas is being wasted through venting and flaring at oil and gas production sites on Federal and Indian lands, despite the fact that this gas could be economically captured and delivered to the market. The RIA cites a 2008 GAO estimate that about 128 billion cubic feet of natural gas was either vented or flared from Federal leases, of which 50 billion cubic feet was economically recoverable.[13] The BLM claims that this recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon monoxide equivalent emissions.

   This reasoning does not reflect the current state of the market. First, the average natural gas price for the full year 2008 was $8.85 per MCF. This compares to a spot price in March of 2016 of just $1.40.[14] This is an 84 percent drop in the price of natural gas since the 2008 time frame which the GAO uses in its report. Based on the 84 percent reduction in the price of natural gas, the $23 million dollar figure presented by the BLM would drop to $3.68 million.

   Further, the RIA states that in 2013, about 98 Bcf of natural gas was vented and flared from Federal and Indian leases. At a $4/Mcf price of natural gas, this volume has a sales value of $392 million and a royalty value of $49 million. Of the 98 Bcf, the BLM estimates that 22 Bcf was vented and 76 Bcf was flared. The agency also estimates that 44 Bcf of the flared gas came from the Federal and Indian mineral estates with 32 Bcf coming from the estates of other mineral owners.[15]

   Therefore, the BLM in its analysis neglects to evaluate the current market landscape in terms of prices and industry dynamics which indicate rising inventory levels of natural gas and the potential for a

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13 Op. cit. Regulatory Impact Analysis, page 2.

14 Braziel, E. Russell, The Race To Liquids, Oil & Gas Finance Journal, August 1, 2010, on-line at: www.ogfj.com/articles/print/volume-7/issue-8/features/the-race_to_liquids.html; CNBC.com for March 14, 2016 natural gas price.

15 Op. cit. Regulatory Impact Analysis, page 3.

supply glut. Natural gas prices have been as low as $1.40 per Mcf in March of 2016 or 65 percent lower than the RIA estimate, implying a sales value not of $392 million and a royalty of $49 million but a number closer to $137.2 million in sales and $17.15 million in royalties.

Adding in the economic marginal impact of the additional volume in a market landscape with heavy inventories it could easily be assumed that all of that volume may be much lower and could have a marginal value approaching $0.

2. An explanation of how the proposed regulatory action will meet that need:
The BLM, with this proposed regulatory action explicitly seeks to enhance waste prevention and resource conservation. Explicitly stated and often discussed is methane reduction. The ability to measure methane reduction and tie it to conservation is not readily achievable. Air quality and pollution control regulations address "negative externalities" which represent the cost of pollution which is borne by society rather than producers. The RIA presupposes that methane emissions impose costs on society, such as negative climate, health, and welfare impacts that are not reflected in the market price of the petroleum produced. This can indicate that there is a need to promulgate regulations that minimize these costs. However, many scholars, including for example, Nobel Lauriat Ronald Coase, have suggested that there are other ways for society to alleviate the consequences of negative externalities. In fact, correcting an externality may impose externalities on different groups of people. This is why the OMB requires that all RIA submissions include an alternatives analysis.

   Without a proper baseline to measure the effects of the regulations, it is impossible to determine if they will meet the need of reducing any economic costs associated with "methane reduction."

3. An appropriate baseline assessment of how the world would look in the absence of the proposed action: **BLM does not provide a "null analysis" in its RIA.** There are no estimates of how this additional volume of natural gas that is brought to market would impact the current price of natural gas.

4. An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action: **Only a very general alternatives analysis is presented in the RIA.** Royalty rate alternatives were discussed in general terms with no analysis performed. In fact, only one actual alternative was presented and it related to the flaring of gas. This alternative simply reduced the amount of gas flared to 20 million cubic feet. This is not, as suggested by OMB, a range of potentially effective and reasonably feasible regulatory alternatives including deferral to state or local regulation, the use of economic incentives to encourage the desired behavior, market-oriented approaches, different compliance dates or different requirements depending on firm size. The whole reason for an RIA is to examine alternatives and weigh the costs and benefit of different approaches to achieving the same goal. The BLM's RIA completely fails on this important aspect. Additionally, this arbitrary number does not examine a significant issue, the appropriate amount of venting or flaring to achieve maximum safety.

5. An explanation of why the planned regulatory action is preferable to the potential alternatives: **One alternative was presented, but there is no explanation of why the BLM's preferred regulatory action is preferable. Additionally, very uncertain and potentially unrealistic natural gas price estimates were used.**

6. An uncertainty analysis: The BLM presents a sizable degree of uncertainty in just about every listed benefit that it claims the proposed rule would generate. In fact, the Agency suggests that it cannot even determine what the price of natural gas will be in the future. The BLM states that it "believes" that there are economical and cost-effective measures that operators could take to minimize waste

based on advancements in technology, yet they cite no advancements that would be relevant to minimizing waste.

7. A description and discussion of the distributive impacts of the potential alternatives: While the RIA contains a section labeled *Distributional Effects*, it only examines the impact of the regulations across two categories: Small vs. large businesses and across potential pollution sources. OMB states that the analysis of the distributional effects should examine the impact of the proposed action across the population and economy divided up by a range of demographic and economic categories.[16] **This is not an analysis of the distributional impacts of the proposed rule as laid out in OMB Circular A-4.**

   The need for a distributional analysis is particularly acute in that these regulations are geared toward a single industry – oil and natural gas production. Other methane producing industries are not included. Higher costs in one industry reduce investment and activity in that sector and as such, encourage investment and activity in another. If capital were to move from the production of oil and natural gas to the production of say beef cattle, then the amount of methane produced may actually increase. If this has an effect on "climate change," the effect may be greater. More importantly, since oil and natural gas can be produced in many different countries the regulations may simply transfer activity from the United States to Russia, Mexico, Iraq or Nigeria. This can not only impact the American economy but could also lead to increased methane production.

   Most importantly, the RIA completely fails to examine how the proposed regulations impact different segments of society and different areas of the country, a requirement specifically outlined in OMB Circular A-4.

8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action: **This is included in the analysis.**

9. A clear and transparent table presenting anticipated benefits and costs: **The analysis presents the calculated benefits and costs in a clear table.**

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner: As with many RIA documents, the agency involved is using the analysis to justify its proposed regulatory action. First the best data are not used. Specifically, data for natural gas prices at the peak of their historical range (2008) are utilized. Additionally, company profitability estimates come a select list of10-K financial filings from 2012-2014 for a sample of companies that are assumed to represent the industry. Survey data is also analyzed second-hand and not provided in raw form to the public.[17] What is even more astounding is that nowhere in the RIA is the volatility and economic hardship of the industry in 2015/2016 even stated. Much of this data is

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[16] Specifically Circular A-4 States: *Those who bear the costs of a regulation and those who enjoy its benefits often are not the same people. The term "distributional effect" refers to the impact of a regulatory action across the population and economy, divided up in various ways (e.g., income groups, race, sex, industrial sector, geography). Benefits and costs of a regulation may also be distributed unevenly over time, perhaps spanning several generations. Distributional effects may arise through "transfer payments" that stem from a regulatory action as well. For example, the revenue collected through a fee, surcharge in excess of the cost of services provided, or tax is a transfer payment.*

Your regulatory analysis should provide a separate description of distributional effects (i.e., how both benefits and costs are distributed among sub-populations of particular concern) so that decision makers can properly consider them along with the effects on economic efficiency. See: Office of Management and Budget, *Circular A-4*, September 17, 2003, at: www.whitehouse.gov/omb/circulars_a004_a-4#f.

[17] This specific survey data was analyzed by Carbon Limit (a consulting firm).

now out of date and not indicative of either the pricing environment for oil or gas, nor are the company financial filings reflective of the current financial state of the industry.

BLM bases its assumptions on the benefits related to reduced methane emissions, on past Environmental Protection Agency (EPA) analysis and on pronouncements from a Federal interagency working group. The RIA states that BLM has estimated "the quantity of methane reduction using emissions factors and reductions data made available by EPA."[18] BLM also states that it estimates the social cost of methane using the values presented by Marten et al (2014), EPA's analysis of Subpart OOOOa and EPA's New Source Standards for Municipal Solid Waste Landfills. Further, BLM states that they estimated social cost of carbon dioxide on the Interagency Working Group on Social Cost of Carbon.[19]

This is not a complete analysis and is clearly biased because the BLM must first have established that those methane emissions that might be prevented by this rule actually impact "climate change" in some way. OMB requires agencies to establish a baseline which represents the agency's best assessment of what the world would be like absent the action. This baseline needs to focus on benefits and costs that accrue to citizens and residents of the United States. According to OMB, where the agency chooses to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.[20] Nowhere in the document does the BLM document any baseline cost of climate change on the economy of the United States. As such it is impossible to determine if the benefits anticipated by the BLM even accrue to the American economy. It is also impossible to determine if they have any meaningful effect on the overall factor being measured, that is the perceived economic cost of "climate change."
Without a proper baseline to measure the effects of the regulations, it is impossible to determine if they will meet the need of reducing any economic costs associated with "climate change."

Additionally, the entire benefits calculation done by BLM is based on an EPA analysis which in itself is based on an extremely fragile examination of the "climate change" benefits. The values are not derived from any models presented in the study, but rather from a book published in 2000 which purports to measure the cost of supposed "climate change" due to carbon dioxide (CO2) emissions.[21]

The EPA analysis which BLM incorporates, states that although several researchers that had directly estimated the social cost of non-CO2 GHG emissions, there was considerable variation among these published estimates both in terms of the models and assumptions. Furthermore, none of the other published estimates of the social cost of non-CO2 GHG were consistent with the CO2 estimates developed by an interagency working group (IWG) that included other executive branch agencies which used three integrated assessment models (IAMs) to develop the CO2 estimates used in this RIA. These CO2 estimates were first released in February 2010 and updated in 2013. In other words, the analysis uses assumptions unilaterally decided on by the Federal Government to measure a social cost of CO2 emissions.

Also, BLM goes on to suggest that a paper published by Marten (2014) provides the first set of published methane estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the CO2 estimates. What the agency fails to mention is that the authors of this paper are all staff of the EPA. In fact, the Marten article does not even generate its own estimates of the potential economic benefits of reduced methane emissions, but rather calculates estimates of

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18 Op. cit. Regulatory Impact Analysis, page 32.

19 Ibid

20 Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, at: www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf.

21 Nordhaus, William D. and Joseph Boyer, Warming the world : economic models of global warming, Massachusetts Institute of Technology, 2000. Available on line at: http://eml.berkeley.edu/~saez/course131/Warm-World00.pdf

climate impacts of methane relative to CO2. In doing this the authors come up with a range of values of from $349 and $1,183 per ton, a 239 percent difference. In short, the figures used to calculate the purported benefits are based on an EPA sponsored paper that examines data on CO2 and makes a number of assumptive jumps to methane impacts. Even this paper admits to an extreme level of variation in its modeled figures.

This particular failing of the RIA is critical. In fact, this entire RIA presents little in the way of actual analysis. Rather it ties together a number of policy statements, and uses policy documents to support them. The RIA first determines that the production of oil and gas leads to the emissions of methane. From this point, the entire calculation of benefits is based on findings that are determined by the BLM to be self-evident, but which are not supported by facts. First, all of the literature cited about potential "climate change" costs of methane actually discusses CO2. The BLM bases their analysis on EPA, which then uses a paper produced by its own staff, which describes internal procedures used by EPA to translate methane into CO2 equivalents. While this paper may appear in a "peer-reviewed" journal, the paper and the journal were about internal bureaucratic processes, not chemistry.[22] In other words, it is saying "trust us" we know how this works.

BLM then multiplies these derived CO2 equivalents by a cost factor that comes not from independent research, but rather from an internal Administration working group. As such, these cost figures are not determined in an unbiased and independent manner, but by the agency that is promulgating the regulations. In fact, the entire process hinges on the unsupported assumption that the minor levels of methane emissions identified as coming from oil and natural gas developments have a negative effect on the economy. The entire analysis can be summarized by the simple statement, "Methane emissions have a negative effect on the economy because we (the BLM) say so." **This suggests that the RIA might not have been conducted in a non-biased manner.**

11. Provide the data, sources and methods used in the RIA to the public via the internet: While the report is extensively cited, much of the source material is not readily available or is not available without some additional cost. **The BLM does not provide a library of the materials or data used in its analysis that is available to the public without additional cost.**

12. Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible: **The RIA does not demonstrate a way to monetize the proposed benefits, but only quantifies a purported economic benefit from the regulatory action which is between $255 and $384 million annually depending upon various assumptions.**[23] There are some major analytical leaps to monetize these benefits, and the actual figures are all based on 2008 commodity prices, material lifted from 10-K reports from 2012-2014, and survey data from 2012 – 2014, which was analyzed second hand by a firm called Carbon Limits which focuses on climate change mitigation.[24]

    Also for example, the largest line item, leak detection and repair (LDAR) compromises $88-$119 million dollars of the $255 to $384 million benefit (roughly one third). In regards to this, the BLM states that "the impacts of an LDAR requirement are uncertain."

    Also, flaring requirement estimates show a potential $7 to $16 million cost (not benefit).

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22 Peer review is not a euphemism for fact. Many journals publish papers on topics that the reviewers are not familiar with. Papers may be published because the present an interesting data set, a new process, or a formal analysis. In this case, the paper was published because it described an internal EPA process, not because it presented the results from a chemical experiment.

23 Op. cit. Regulatory Impact Analysis, page 6.

24 Op. cit. Regulatory Impact Analysis, page 222.

The old data, broad ranging estimates and potential negative values significantly lower the actual benefits. Utilizing current data and modern analytical techniques would bring the total benefit $90 million.

13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible: According to the RIA, the costs to implement the proposed regulations could reach $174 million per year.[25] This is well below the actual cost of implementing the rules as proposed. In fact, JDA estimates that the total cost of implementation of the proposed rules to the industry is a staggering $1.26 billion dollars on an annual basis.

The cost components are in eight categories: Flaring Requirements, Well Completion, Pneumatic Controllers, Pneumatic Pumps, Liquids Unloading, Storage Tanks, LDAR, Administrative burden.

These numbers are derived primarily from certain key assumptions contained in the RIA and cited by the BLM. These are:

- A total of 37,000 – 38,000 wells are potentially impacted by LDAR inspections
- Flaring limits affect no more than the RIA's stated 1,111 well sites
- Flare metering rules affect no more than 635 sites
- Well drilling, completions and maintenance proposed rules will affect no more than 1,575 wells
- Liquids unloading proposed rules affect more than 1,550 well
- There are no additional exploration leasing and permitting costs

Table 1 presents the eight components and the costs per well.

Table 1
Costs by Component[26]

Affected Component	Cost per well	Number of affected wells
Flaring (total including limits and metering)	$73,583	1,111
Well Completion	$7,619	1575
Pneumatic Controllers	$384	15,600
Pneumatic Pumps	$307.69	8775
Liquids Unloading	$3,871	1550
Storage Tanks	$20,625	3,200
LDAR	$3,736.00	38,000
Administrative burden	$67.34	38,000
Total	$110,193	

The BLM's high end estimate would be the lowest reasonable cost estimate. However, the number of wells serviced per year could be much higher than 38,000 and potentially double the amounts listed above, which could drive these costs much higher. If the given range is $117 - $174 million, doubling of the wells service count would increase the cost range to $234 - $348 million.

14. Explain and support how the benefits of the intended regulation justify its costs:

[25] Op. cit. Regulatory Impact Analysis, page 81.
[26] Assumes that there are no additional remediation costs as no exploration or new wells are being produced.

Any benefits at all rely on two criteria, the recovery and sale of natural gas and natural gas liquids and the assumed benefits of reduced methane emissions.

From a macro level the recovery and sale of natural gas and gas liquids is a highly questionable endeavor in these market conditions, The RIA states that the BLM is "unable to account for existing LDAR programs, and that these benefits likely overstate the true benefit of the rule."[27] The LDAR benefit is the largest benefit component of the rule.

Further, market dynamics continue to be highly volatile as commodities specifically natural gas are currently perceived to be super-cyclical with global demand weakening inventory build may take years to work themselves out. During this period of time adding additional volume to the market could very well not be feasible.

Additionally, in regards to methane benefits, the science is unclear as to whether a social cost benefit exists for reduced methane. As discussed in point 10 above, BLM bases their methane benefit on EPA analysis, which rests on a potentially unstable academic foundation. Without further analysis and robust debate, the BLM cannot assume that there is any benefit at all to reduced methane emissions.

15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach: **A new estimate based on 2016 data, specifically prices should be conducted to reflect accurate net benefits.**

16. Use appropriate discount rates for benefits and costs expected to occur in the future: The BLM discounts its cost estimates using discount rates of three percent and seven percent; however, these are applied individually as separate analyses, and not used appropriately to discount effects on private capital (7 percent) and effects on private consumption (3 percent) as suggested by the OMB. **The discounting performed in the RIA is, therefore, not properly conducted.**

The Economic Impact of the Proposed Rules:

Table 2
Reduction in Oil Well Development Due to Proposed Rules

State	Estimated BLM Wells	Estimated Lost Wells	Well Loss Percent	Potential Lost Barrels of Oil
Arizona	2	-	0.00%	-
Colorado	6,878	(934)	-13.58%	(4,664,186)
Montana	2,819	(115)	-4.07%	(855,323)
Nebraska	31	(31)	-100.00%	(24,849)
Nevada	118	-	0.00%	-
New Mexico	30,490	(1,330)	-4.36%	(12,209,466)
North Dakota	1,874	(1,335)	-71.23%	(87,290,963)
South Dakota	87	(8)	-9.73%	(2,290)
Utah	8,909	(416)	-4.67%	(3,589,667)
Wyoming	31,647	(537)	-1.70%	(3,726,608)
Total	82,855	(4,707)	-5.68%	(112,363,352)

[27] Op. cit. Regulatory Impact Analysis, page 130.

The costs imposed by the proposed rules would significantly impact the economic dynamics of the oil and gas industry. Based on JDA's dynamic model of the oil and natural gas industry, it is likely that as many as 4,700 fewer oil wells would be undertaken as a result of the rules.

Table 3
Economic Impact of Proposed Rules

State	Direct Jobs	Total Jobs	Direct Wages	Total Wages	Direct Output	Total Output
Colorado	(313)	(461)	$ (31,354,725)	$ (40,564,096)	$ (111,825,404)	$ (135,583,684)
Montana	(22)	(35)	$ (1,891,244)	$ (2,442,224)	$ (6,906,425)	$ (8,671,377)
Nebraska	(4)	(4)	$ (203,759)	$ (218,971)	$ (823,259)	$ (871,976)
New Mexico	(284)	(432)	$ (22,738,385)	$ (29,643,023)	$ (88,125,869)	$ (109,183,574)
North Dakota	(936)	(1,777)	$ (101,895,616)	$ (144,462,783)	$ (253,428,069)	$ (377,768,038)
South Dakota	(1)	(2)	$ (51,516)	$ (92,917)	$ (228,566)	$ (395,277)
Utah	(103)	(202)	$ (8,035,385)	$ (12,813,377)	$ (27,294,340)	$ (42,191,094)
Wyoming	(118)	(144)	$ (11,446,685)	$ (12,736,722)	$ (50,313,519)	$ (54,363,414)
Entire United States	(1,780)	(3,845)	$ (177,617,315)	$ (308,296,515)	$ (538,945,451)	$ (977,199,362)

By reducing new oil and natural gas development, and potentially reducing continuing operation of marginal fields, the proposed regulations could have significant impacts on employment in regions where there are developments on BLM lands. This is particularly important considering that the industry is already suffering substantial job losses due to the current low market prices for petroleum products. Based on models developed by John Dunham and Associates for Western Energy Alliance, these proposed rules could result in as many as 1,780 lost jobs for people directly involved with oil and natural gas development and production, and as many as 3,850 jobs once all supplier and induced impacts are taken into account.[28] These are real people with real jobs, currently receiving as much as $308.3 million in wages and benefits. All told, the economy could lose as much as $977.2 million in overall economic output annually.

This lost economic activity will have a significant and direct fiscal effect, that in and of itself would be larger than any potential benefits that might result from the proposed rules. It is estimated that the annual fiscal effect of the proposed rules would be as high as $114.1 million, of which $65.6 million represents lost federal taxes. The remaining $48.5 million in lost revenues would be seen by states and local governments that depend in part of revenues from the development of oil and natural gas fields.

Table 4
Fiscal Impact of Proposed Rules

State	Federal Taxes	State Taxes	Total Taxes
North Dakota	$ (26,243,000)	$ (11,087,000)	$ (37,330,000)
Colorado	$ (7,591,000)	$ (4,964,000)	$ (12,554,000)
New Mexico	$ (5,548,000)	$ (4,771,000)	$ (10,319,000)
Wyoming	$ (3,162,000)	$ (2,272,000)	$ (5,434,000)
Utah	$ (2,130,000)	$ (2,026,000)	$ (4,155,000)
Montana	$ (464,000)	$ (337,000)	$ (800,000)
Nebraska	$ (7,000)	$ (21,000)	$ (28,000)
South Dakota	$ (8,000)	$ (7,000)	$ (15,000)
United States	$ (65,601,000)	$ (48,511,000)	$ (114,112,000)

Conclusions:

[28] Based on John Dunham and Associates, *Western Oil & Natural Gas Employs America*, prepared for Western Energy Alliance, 2014, at: www.westernenergyalliance.org/employsamerica

A careful analysis of the facts laid out in the RIA leads to one clear conclusion, and that is that the costs of $1.26 billion annually to the economy far outweigh even the highest end BLM benefit estimate of $384 million.[29] This is based on a price for natural gas of $2.00/Mcf.[30]

This year, natural gas prices have dropped to as low as $1.57 per million BTU and $1.40 Mcf according to the EIA and media sources cited above. Discounting the idea that a reduction in potential methane emissions would have any benefit on the environment that could be monetized[31], a more reasonable calculation of the potential benefit of the proposed rule would be $90 million.

With a cost of $1.26 billion and a potential benefit of just $90 million, this rule does not produce a net social benefit.

In addition to not completing the RIA in accordance with published OMB guidelines, the BLM included a number of assumptions that were on their face either false, or should not have been used as part of this type of analysis. The most glaring problem is the BLM's inflated commodity price estimate which underlies the entire economic benefit claimed. BLM fails to acknowledge that at current commodity prices the oil and natural gas industry is in its biggest bear market in 30 years, and implementing this extremely expensive rule would have a very adverse impact in such a depressed market, and will lead to lost development on federal lands. Additionally, BLM fails to address the fact that the rule in its imposition of a no venting standard would lead to unsafe drilling, completion and storage practices, which is not examined in any real depth in the RIA.

The BLM's failure to conduct a comprehensive alternative analysis was clearly in violation of the OMB guidelines. An alternatives analysis may have shown that the proposals could actually lead to increased and significant economic costs to the oil and gas industry.

Given such flawed analysis and self-reported doubts by the BLM in the RIA, it is very possible that a new analysis would find significantly varied results.

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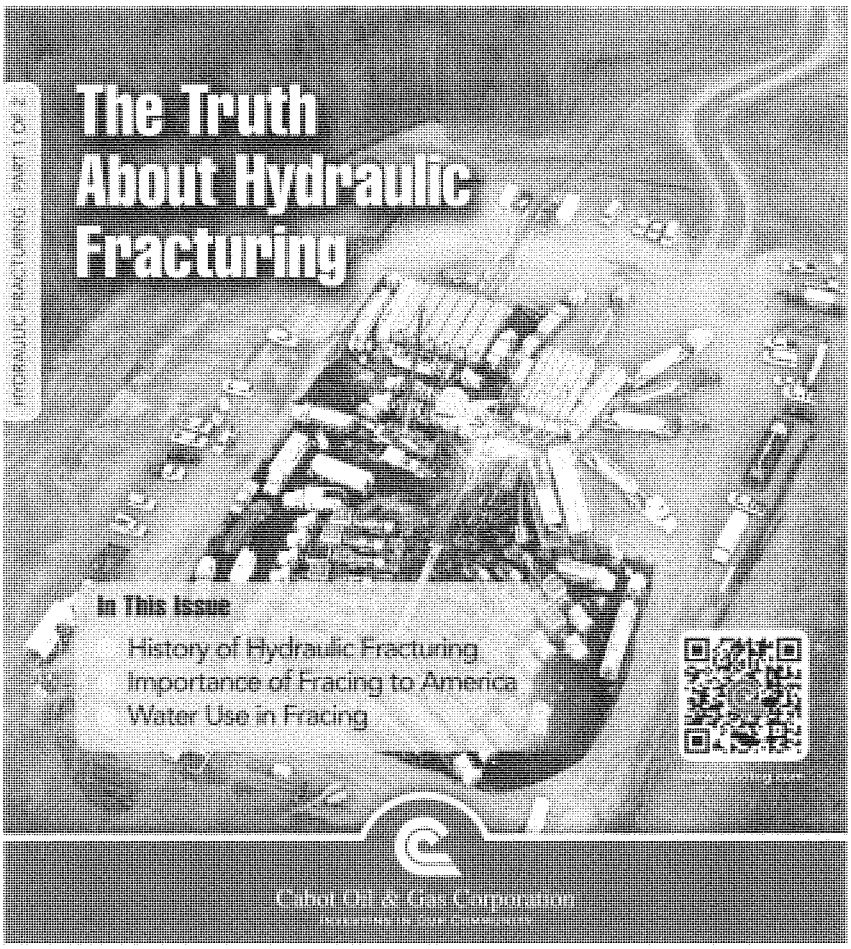
29 Op. cit. Regulatory Impact Analysis, pages 6-8.

30 Op. cit. Regulatory Impact Analysis, page 42.

31 The benefits as laid out by the BLM are also speculative at best as they rely on passage of EPA Subpart OOOOa and rely on certain assumptions that methane gas reductions have a social cost benefit.


The Truth About Hydraulic Fracturing
In This Issue
History of Hydraulic Fracturing
Importance of Fracing to America
Water Use in Fracing
Cabot Oil & Gas Corporation

COMPARED TO TRADITIONAL VEHICLES, THOSE OPERATING ON COMPRESSED NATURAL GAS HAVE REDUCTIONS IN CARBON MONOXIDE EMISSIONS OF 90 TO 97%, AND REDUCTIONS IN CARBON DIOXIDE EMISSIONS OF 25%.

2

WHAT IS HYDRAULIC FRACTURING?

Despite what you may have heard, hydraulic fracturing (often called "fracing" and incorrectly written as "fracking") is not a drilling process. It's a procedure that takes place after the drilled hole, or wellbore, is completed. In fact, the hydraulic fracturing process does not even occur while the drilling rig is on location.

As you can see on the front of this issue, the aerial photograph of the Heitzenroder pad site shows that most of the equipment present during the completions process are water trucks and hoses. It should be noted that site was fully tarped in black plastic for environmental protection purposes.

Put simply, hydraulic fracturing is the use of fluid and material to create or restore small fractures in a formation in order to stimulate production from new and existing oil and gas wells. These fractures are very small - so small in fact that they are propped open by granules of sand, called proppant. This creates enough space to release the natural gas trapped in the rock and allow it to safely rise to the surface within the self-contained system.

FRACING...SAFE AND EFFECTIVE FOR OVER 60 YEARS

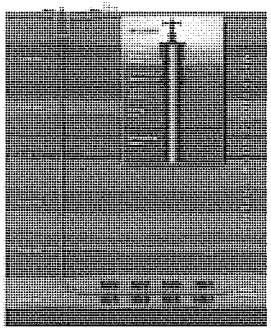
Since hydraulic fracturing was first introduced commercially in the 1940s, the process has been successfully used in over 1 million producing wells. Today, fracing is used in a majority of U.S. oil and natural gas wells to enhance well performance, minimize drilling and recover otherwise inaccessible energy resources. Today's wells can access over 60 times more below-ground area and retrieve the same amount of gas while producing 30% less waste than a decade ago.

In fact, 90% of all natural gas wells drilled in America use fracing to increase production, and there has never been a single case of groundwater pollution caused by the underground fracing process. That's not only due to industry safety precautions, but also because of the basic properties of the depth of rock layers.

To view a video on hydraulic fracturing, use your smartphone to photograph this QR code.

Why is Fracing So Important?

The fracing process is essential to developing the clean-burning natural gas resources of the Marcellus Shale. That's because the formation exists a mile or more below the surface. These depths plus the solid or "tight" nature of the shale make the gas trapped in the formation difficult to develop. Successful wells must produce a large amount of natural gas to justify the time, effort and expenses involved in creating and maintaining them.



Example of hydraulic fracturing for shale development

Water Use in the Hydraulic Fracturing Process

Water is a necessary part of the fracing process as it acts as a carrier fluid for the propping agents (grains of sand) used to prop open the tiny channels created to induce the flow of natural gas out of the rock formation.

The hydraulic fracturing process requires the greatest amount of water when drilling and completing a natural gas well. Cabot uses approximately 3,990,000 gallons of water in our Susquehanna County wells – approximately 3,780,000 gallons of that is used for fracing. While this may seem like a lot, it's equal to a mere 5.5 minutes of water usage in New York City.

Cabot also utilizes a closed-loop system to recycle up to 100% of the water used in our operations – including hydraulic fracturing – for use in later operations. This greatly reduces the volume of fresh water taken from local rivers and creeks while eliminating the need for open fluid pits.

A Key Part of America's Energy Future

America's energy demands are continuing to grow at a tremendous pace. At Cabot, we believe it's essential that America do all it can to develop domestic energy resources to reduce our dependence on foreign energy. That's why hydraulic fracturing plays such an important role in homegrown energy production. Without hydraulic fracturing America would lose close to half of its natural gas production. That's too significant to ignore – especially since the fracing process has been proven so safe and effective for over half a century of oil and gas exploration.

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cabotsusquehanna

www.cabotog.com

Since the 1940s, hydraulic fracturing has been successfully performed in over 1 million wells.

3

Terms around the Industry

Casing
Steel pipe used to line the inside of a wellbore.

JAMES EDWARDS

Completion Manager

Serving as Cabot's Completion Manager, Jim draws on years of engineering experience and expertise to coordinate and oversee best practices used in the hydraulic fracturing of well sites throughout Susquehanna County.

The position calls for daily communications with Cabot's staff of Completion Engineers, Water Engineers and Well Site Supervisors to properly design and manage multiple well site operations. Regular engineering reviews ensure that the more than 100 individuals working at well sites on any given day are following state and federal standards.

By working with Cabot's drilling, production, land and geology specialists, the Completion Manager helps make sure the hydraulic fracturing procedure is performed in a way that's efficient, effective and environmentally safe. Only then is it deemed a success.

Jim says he loves the friendly, hardworking people and beautiful landscape of Susquehanna County. And wants everyone to know that "the hydraulic fracturing process is managed by professionals like myself. We enjoy the outdoors and are dedicated to protecting the environment for the future generations to come."

Learn More About Hydraulic Fracturing in our

Next Issue

- Frac Focus & Frac Fluids
- Hydraulic Fracturing Process
- Flaring

Cabot Oil & Gas Corporation

INVESTING IN OUR COMMUNITY

Cabot Oil & Gas Corporation is an independent natural gas producer and a leading developer of the natural gas supply contained in the Marcellus Shale in Susquehanna County, Pennsylvania.

VISIT WWW.CABOTOG.COM TO LEARN MORE.

WASHINGTON Examiner (/)

Moniz: Fracking has been good for the environment

By JOHN SICILIANO (HTTP://WWW.WASHINGTONEXAMINER.COM/AUTHOR/JOHN-SICILIANO) • 8/15/16 6:29 PM

The oil and gas boom is reducing U.S. greenhouse gas emissions, Energy Secretary Ernest Moniz said Monday.

"The increased production of oil and natural gas in the United States has, obviously, been a major story in terms of our economy, and also our environment," Moniz said at a field hearing in Seattle convened by Sen. Maria Cantwell of Washington, the top Democrat on the Senate Energy and Natural Resources Committee.

"The natural gas boom, in particular, has led to the displacement of high-carbon coal with low-carbon natural gas producing fewer [carbon dioxide] emissions," Moniz said.

Moniz's comments follow those by the head of the Energy Information Administration, the Energy Department's analysis arm, earlier this month, indicating that carbon emissions are lower than they have been since 1992 because of increased reliance on natural gas from hydraulic fracturing, known as fracking.

Environmental groups have been heaping pressure on the Obama administration, Democrats and Republicans to support a ban on fracking, saying that the natural gas and oil produced from the process are raising greenhouse gas emissions and exacerbating climate change. Instead, they want 100 percent renewable energy.

Monday's hearing was meant to examine the increased pressure that oil and gas production has placed on the nation's infrastructure, especially for Cantwell's state that has become a key chokepoint for shipping U.S. fossil fuels and other commodities to foreign markets.

Moniz said the increased demand for moving oil and natural gas around the country has placed "big strains" on the nation's existing transportation infrastructure, where rail has been increasingly tapped to make up for the lag in pipeline capacity.

Nevertheless, slowing production has reduced pressure of rail shipments nationwide, except for the Northwest and Cantwell's state where traffic remains steady.

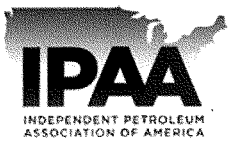
Cantwell, who supports taking steps to fight climate change and reduce emissions, did not appear opposed to keeping the oil trains from continuing to roll into her state. In fact, she said the oil and gas boom has achieved "energy independence" in making the nation less dependent on foreign oil.

"This is a pretty big shift for the United States of America," Cantwell said. "We wanted energy independence. But now we got it."

The issue in front of her is "our own safety and security issues in the Northwest," she said.

The priority is making sure it is transported safely, especially in her state where many of the trains move through highly populated areas to reach Washington's ports.

Her state's concern rises from the possibility of oil train derailments, which have become almost common place in recent years. The derailments have caused fires, explosions and even deaths.



June 16, 2014

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

Submitted via email to oilandgas.whitepapers@epa.gov

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

Dear Administrator McCarthy:

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

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

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

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

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

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

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

A. Comments on Compressors:

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

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

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

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

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

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

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

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

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

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

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

6. ***If there are emissions mitigation options for reciprocating and centrifugal compressors that were not discussed in this paper, please comment on the pros and cons of those options. Please discuss the efficacy, cost and feasibly for both new and existing compressors.***

7. ***Are there technical limitations that make the replacement of wet seals with dry seals impractical at certain existing centrifugal compressors?***

8. ***Are there technical reasons why an operator would use a wet seal centrifugal compressor without a gas recovery system?***

9. ***Are there technical limitations that make the installation of gas capture systems at certain reciprocating compressors impractical?***

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

10. ***Please comment on the prevalence of the different emission mitigation options in the field.***

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

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

We are not aware of ongoing or planned studies.

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

Before addressing the charge questions, we would like to make a few overarching comments that summarize our position related to hydraulically fractured oil well completions and associated gas during ongoing production. As an initial matter, the White Paper on this topic is not clear as to whether these questions apply to new sources, existing sources or recompletions. The responses are likely to vary considerably, with considerable differences for new sources versus existing sources. Additionally, the White Paper is not clear as to what constitutes a "hydraulically fractured oil well." The White Paper cites but does not necessarily endorse the UT Study gas to oil ratio of 12,5000 scf/barrel as a cut point. EPA's New Source Performance Standards Subpart OOOO did not define the difference and it is our understanding that EPA intends to propose some clarification of a "gas well" shortly in a second round of reconsideration rulemaking. A very large percentage of hydraulically fractured wells co-produce oil and gas. It also appears that EPA is relying on studies and statistics based primarily on what are considered "gas wells" and then extrapolating the results to oil well reduced emission completions ("RECs"). It is not that simple due to the different characteristics and operational procedures between gas wells and oil wells and EPA needs to more clearly articulate its assumptions with regard to the data presented in the White Paper. Finally, we question the need or benefit of EPA requiring reduced RECs or combustions devices/flares[1] at oil wells as operators are already engaged in such practices at a majority of the wells. There is a clear economic incentive to capture as much of the gas as possible and where it is not possible to capture the gas, safety concerns for the personnel at the well site drive the installation of flares. It is a matter of economics and common sense—if the gas can be captured economically, it will be. If it cannot be captured economically, and it is present in sufficient quantities to represent a safety concern, it is flared. A "one-size-fits-all" requirement for RECs or flares is unnecessary and will disproportionately affect marginal wells, low pressure wells and energized wells.

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

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

[1] "Combustion device" and "flare" are used interchangeably and are not flares subject to 40 C.F.R. § 60.18.

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

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

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

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

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

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

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

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

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

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

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

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

No.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We are not aware of others.

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

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

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

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

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

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

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

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

We are not aware of any ongoing or planned studies.

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

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

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

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

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

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

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

at Upstream Oil and Gas Facilities" used different emissions factors for different types of sites to account for such differences.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Please see our answer to question 12.

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

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

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

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

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

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

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

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

D. Comments on Liquids Unloading Processes:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

E. Comments on Pneumatics:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

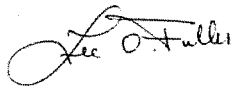
Solar can be and often is used to operate pneumatics in remote areas, however solar and electric systems are not as reliable as natural gas-driven pneumatics and cannot be used universally. It is critical to our members' operations that pneumatic controllers operate reliably for safety and well production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

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

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

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

Sincerely,



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

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

Plunger Lift

Advantages & Disadvantages

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

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Artificial Lift

PIONEER NATURAL RESOURCES

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

Artificial Lift

PIONEER NATURAL RESOURCES

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

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Sucker Rod Pump

Advantages & Disadvantages

Artificial Lift

PIONEER
NATURAL RESOURCES

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

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PIONEER
NATURAL RESOURCES

- **Sucker Rod Pump Advantages**
  - Most field and operating personnel are familiar with sucker rod type lift, the installation and operation is not complicated.
  - Design, analysis, optimization, and surveillance are developed and mature for this lift system.

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

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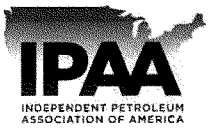

May 30, 2014

Mr. Tim Spisak
Senior Advisor – Conventional Energy
Bureau of Land Management
Washington, D.C.

RE: Comments of IPAA on Bureau of Land Management Venting & Flaring Public Outreach (NTL-4A)

Dear Mr. Spisak:

The Independent Petroleum Association of America ("IPAA") appreciates this opportunity to comment on the information provided during the four Venting & Flaring Public Outreach meetings held by the Bureau of Land Management ("BLM") in March and May of this year.[1] This comment letter supplements preliminary comments jointly filed by IPAA and the American Exploration & Production Council ("AXPC") on May 2, 2014.

IPAA represents thousands of independent oil and natural gas producers and service companies across the United States. Independent producers develop 95 percent of American oil and gas wells, produce 68 percent of American oil, and produce 82 percent of American natural gas.

Our members question the need for new or amended venting and flaring rules because the U.S. Environmental Protection Agency ("EPA") and the states have already promulgated emissions control regulations for oil and gas operations. Several states have recently passed even more stringent requirements, others are poised to do the same, and the EPA is currently seeking comments on five methane reduction strategy white papers. In light of the preceding, we believe that this rulemaking initiative is unnecessary, premature, and would very possibly result in duplicative or inconsistent regulatory requirements.

We also note that, although the sudden rush to revise or replace NTL-4A is very clearly part of the White House's Methane Reduction Strategy, any rulemaking must be conducted under the Mineral Leasing Act ("MLA") and must be based on waste prevention and royalty issues. Some commenters have suggested that the federal Clean Air Act ("CAA") and the

[1] Golden, Colorado (March 19, 2014); Albuquerque, New Mexico (May 7, 2014); Dickinson, North Dakota (May 9, 2014); and Washington DC (May 15, 2014).

Federal Land Policy and Management Act ("FLPMA") provide the BLM with general rulemaking authority over air quality and greenhouse gas ("GHG") standards. These contentions are inaccurate and misplaced because Congress reserved this authority to the EPA and the states.

In addition to these statutory issues, IPAA notes that a venting and flaring rulemaking may prove counterproductive—reducing royalties by driving capital investments away from federal lands. Oil and gas production involves very large capital expenditures and several of the BLM's proposed measures would further increase capital requirements and could even strand investments by imposing retroactive requirements. In particular, our members are concerned that periodic reevaluation of infrastructure requirements could lead to the shut-in and abandonment of wells. IPAA believes that an alternative approach, such as streamlining the permitting process for gas gathering infrastructure, would prove more effective.

In the sections below, we more fully explore the fundamental jurisdictional concerns raised by the information provided during the public outreach process. We also briefly address several of the more significant policy and technical concerns raised by our members.

Under the MLA, Rulemaking is Limited to the Prevention of Waste

We understand that the venting and flaring rulemaking would be an update to NTL-4A, which was last revised on January 1, 1980. In light of pending EPA methane reduction white papers, the ongoing implementation of NSPS Subpart OOOO, and the likelihood of additional EPA rules, and state emissions control regulations, we believe that revising or replacing NTL-4A is unnecessary and premature. If the BLM nevertheless proceeds with a proposal, the proposed regulations must adhere to the intent and limitations of the MLA.

NTL-4A, titled "Royalty or Compensation for Oil and Gas Lost" and issued pursuant to what is now 43 CFR Part 3160 (Onshore Oil and Gas Operations), addresses whether produced natural gas not captured for sale is royalty-bearing. The MLA was the primary authority for these regulations and limits the BLM's authority to revise or replace NTL-4A.[2]

Section 16 of the MLA states that oil and gas permits and leases must require that oil and gas operators "use all *reasonable* precautions to prevent waste of oil or gas."[3] When the

[2] 43 CFR § 3160.0-3 sets forth the statutory authorities for 43 CFR 3160. Although the National Environmental Policy Act ("NEPA") is also one of the listed authorities, we note that NEPA is a procedural statute and does not provide federal agencies with the authority to issue substantive environmental quality regulations.

[3] Emphasis added.

MLA was passed in 1920, the term "waste" meant the unreasonable loss of mineral resources and associated economic benefits. Accordingly, reasonableness is assessed using an economic cost-benefit analysis, with "waste" generally understood to mean a preventable loss, the value of which exceeds the cost of avoidance.[4]

As required by the MLA, the BLM's current regulations for the prevention of waste incorporate both reasonability and economic considerations. The BLM has defined "waste of oil or gas" as including "avoidable surface loss of oil or gas," meaning venting or flaring of produced gas resulting from negligence, a failure to take "all *reasonable* measures to prevent and/or control the loss," or a failure to comply with applicable regulations and orders. [5] Operators must market hydrocarbons, but only if doing so is "economically feasible."[6]

NTL-4A further clarifies whether natural gas venting and flaring is avoidable (and therefore royalty-bearing). In general, royalties do not attach if the gas is used for beneficial purposes, vented or flared pursuant to BLM or state agency authorizations, or unavoidably lost. For example, venting or flaring is authorized for certain well purging and well testing activities and storage tank emissions are recognized as an unavoidable loss.

There are two provisions in 43 CFR Part 3160 that address environmental quality. 43 CFR § 3161.2 directs the BLM to require that operations be conducted in a manner which protects environmental quality and 43 CFR § 3162.5-1 imposes corresponding obligations on operators. We anticipate that the BLM will receive comments portraying these regulatory provisions as a mandate for the BLM to stray beyond waste minimization and royalty issues.

However, the BLM has explained that these provisions merely require compliance with other applicable laws, such as the Safe Drinking Water Act, that are not themselves statutory authorities for the 43 CFR Part 3160 regulations.[7] Accordingly, these provisions are not based on some hypothetical general authority in the MLA pursuant to which the BLM may promulgate sweeping environmental quality regulations. Quite the opposite, these provisions are part of a regulatory structure in which the BLM must condition oil and

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[4] *See* WILLIAMS AND MEYERS, OIL AND GAS LAW vol. 8 at 1133 (2013) (citing McDonald, *Petroleum Conservation in the United States: An Economic Analysis* (1971)).

[5] 43 CFR § 3160.0-5 (emphasis added).

[6] *Id.* § 3162.7-1(a).

[7] 47 Fed. Reg. 47,758, 47,759 (Oct. 27, 1982).

gas authorizations on compliance with environmental programs (including air quality) over which it does not have jurisdiction.

In sum, the MLA, and the BLM's implementing regulations do not prohibit all oil and gas waste—they require only *reasonable* and *economic* measures for the prevention of waste. If the BLM proceeds with a regulatory proposal, the agency must ensure, pursuant to the MLA, that the rule is based on (and limited to) the reasonableness and economic feasibility of preventing and minimizing the waste of oil and gas resources.

The BLM Cannot Establish Air Quality Standards and Implementation Plans

In its public outreach sessions, the BLM communicated that, if a venting and flaring rule is proposed, its scope would be based, not on air quality, but on waste minimization and royalty concerns. As discussed above, IPAA believes that any rules proposed must be based on the MLA and that statute's narrow focus on the reasonable and economically feasible minimization of waste.

However, numerous commenters have urged the BLM to focus its rulemaking efforts on ambient air quality and climate change concerns, on grounds that certain provisions in FLPMA and the CAA provide the requisite authority. These allegations are incorrect—FLPMA and the CAA require the BLM to condition oil and gas approvals on compliance with CAA requirements established by the EPA and the states, but otherwise limit the BLM to an advisory role. As discussed below, any rulemaking based on air quality concerns would trespass on the express jurisdictions of the EPA and the states, contrary to Congressional intent.

The CAA Reserves Air Quality Jurisdiction to the EPA and the States

The CAA "creates a complex regulatory regime designed to protect and enhance the quality of the Nation's air resources."[8] The essential structure of the modern CAA emerged in 1970, when Congress amended the statute to require that the EPA establish primary and secondary National Ambient Air Quality Standards ("NAAQS")[9] and that the states develop

[8] *Sierra Club v. Jackson*, 648 F.3d 848, 851 (D.C. Cir. 2011) (citing 42 U.S.C. § 7401(b)(1)).

[9] The primary NAAQS are established based on the protection of public health. The secondary NAAQS are set based on "public welfare," meaning a wide set of potential concerns, including visibility impacts and impacts on wildlife and vegetation. *See* 42 U.S.C. § 7409(b).

State Implementation Plans ("SIPs")[10] designed to bring nonattainment areas into compliance with the NAAQS.

The CAA ensures nationwide consistency through the establishment of air quality standards and oversight by the EPA, while also promoting flexibility by allowing the states to determine the nature and scope of the emissions control measures best suited, based on their separate circumstances, to achieving and maintaining compliance with the NAAQS.[11] Significantly, Congress assigned each state the "primary responsibility for assuring air quality *within the entire geographic area comprising such state* . . . ."[12] This structure does not provide a jurisdictional role for the BLM.

The CAA Provides Only Limited, Advisory Roles for Federal Land Managers

In 1977, Congress amended the CAA to establish the Prevention of Significant Deterioration permitting program and provisions addressing visibility at "Class I" areas, such as national parks. Congress assigned the EPA responsibility for promulgating a list of Class I areas for which visibility is an important value and assigned the states responsibility for revising their SIPs to include measures to make reasonable progress towards national visibility goals.[13]

Significantly, Congress provided only a very limited role for federal land managers, such as the BLM. Most relevant here, 42 U.S.C. § 7475(d)(2) states that federal land managers must consult with the EPA regarding whether certain proposed major stationary sources could have an adverse impact on air quality related values within a Class I area and may file notices alleging that these sources may cause or contribute to a change in air quality.[14]

The above provision states that federal land managers "have an affirmative responsibility to protect the air quality related values (including visibility) of any such lands within a

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[10] Under certain circumstances, such as a state's failure to submit an approvable SIP, the EPA may backfill by promulgating a Federal Implementation Plan (FIP). 42 U.S.C. § 7410(c). The CAA does not provide for the issuance of FIPs by other federal agencies.

[11] "The Congress finds that air pollution prevention . . . and air pollution control at its source is the primary responsibility of States and local governments . . . ." 42 U.S.C. § 7401(a)(3).

[12] 42 U.S.C. § 7407(a) (emphasis added).

[13] 42 U.S.C. §§ 7491(a)(2) & (b)(2).

[14] Federal land managers were also required to consult with the EPA regarding the EPA's promulgation of a list of Class I areas for which visibility is an important value and to consult with the states on proposed revisions to SIPs. 42 U.S.C. §§ 7491(a)(2) & (d).

class I area . . . ." Some commenters have cited this language, without context, to incorrectly assert that it provides the BLM with general authority to pass air quality standards and to otherwise base revisions to NTL-4A on air quality concerns.

To counteract any misperception, we note that this language is buried in the air permitting provisions. Read with the surrounding text, the "affirmative responsibility" of federal land managers is merely to consult with the EPA and to provide notice where a proposed major stationary source may cause a change in air quality. As acknowledged by other federal land managers, this provision does not provide a basis for the BLM or other federal land managers to issue air quality standards or implementation plans.[15]

Other than the advisory role described above, the CAA includes "conformity" provisions that prohibit the BLM and other federal agencies from engaging in, supporting, or approving any activity which does not conform to a CAA implementation plan (i.e., a SIP or FIP).[16] These provisionswere primarily passed to force federal agencies to meet the same requirements as industry and other sources of air emissions and do not provide a basis for the BLM to pass air quality standards.[17]

BLM Regulation of Air Quality Would Infringe the Jurisdiction of the EPA and the States

Based on the above, it is exceedingly clear that Congress did not intend for federal land managers, including the BLM, to function as air quality agencies. Those roles were assigned exclusively to the EPA and the states, with other agencies serving as consultants in narrowly-defined areas. This structure was already clear in 1970, was reinforced by the dearth of air quality provisions in FLPMA (1976), and was reaffirmed by the 1977 CAA Amendments.

Our members have expressed strong concerns that the BLM intends to regulate venting and flaring from oil and gas operations based on air quality goals, and not the MLA, despite Congressional intent that jurisdiction over these issues be reserved to the EPA and the

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[15] In a 2010 report, the U.S. Forest Service, the National Park Service, and the U.S. Fish & Wildlife Service all stated that "[federal land managers] have no permitting authority under the Clean Air Act, and they have no authority under the Clean Air Act to establish air quality-related rules or standards." *Federal Land Managers' Air Quality Related Values Work Group (FLAG): Phase I Report—Revised (2010)* at xii (Oct. 2010), *available at* http://www.nature.nps.gov/air/pubs/pdf/flag/FLAG_2010.pdf.

[16] 42 U.S.C. § 7506(c).

[17] Of note, the conformity provisions do not allow federal agencies the discretion to determine when and how to make conformity decisions—Congress assigned even that level of authority to the EPA. 42 U.S.C. § 7506(c)(4)(A) ("The Administrator shall promulgate, and periodically update, criteria and procedures for determining conformity . . . .").

states. Our members are also concerned that the BLM will impose regulations which duplicate and/or conflict with EPA and/or state requirements.

In support, we note that many of the venting/flaring reduction options included by the BLM in the materials presented during the four public outreach sessions were clearly based on air quality measures, in particular the EPA's NSPS Subpart OOOO standards and certain state oil and gas emissions control regulations.

When promulgating air quality regulations, the EPA and the states must make numerous "line-drawing" decisions, such as identifying the emissions sources for which controls are needed, specifying the stringency of controls, and determining whether controls should apply to existing sources. These EPA and state regulations are already effective and the BLM already requires compliance with these regulations as a condition of leases and drilling permits.

Therefore, the only reasons for the BLM to pass regulations based on air quality would be to duplicate EPA and state requirements, which would be unnecessary, or to implement different or more stringent air quality measures. For example, the BLM's venting and flaring slide presentation appears to contemplate extending NSPS Subpart OOOO requirements for gas wells to oil wells and extending requirements for new sources to existing sources. These actions would constitute the BLM impermissibly replacing the regulatory considerations of the EPA and the states with its own contrary judgments.

The end conclusion is simple: to avoid trespassing on the air quality jurisdiction of the EPA and the states, the BLM must restrict its assessment of how and whether to revise or replace NTL-4A to the concerns jurisdictionally permitted under the MLA—waste prevention and royalties.

The BLM Does Not Have Jurisdiction to Regulate GHGs

During the four public outreach meetings, our members heard repeated comments regarding the need for stringent venting and flaring regulations as a means to reduce greenhouse gas (GHG) emissions. We also understand that the sudden rush to rulemaking on this issue is largely driven by the White House's pan-agency methane reduction initiative.

Our comments above regarding the CAA apply equally to the BLM's lack of jurisdiction to regulate GHGs. In addition, we note that the United States Supreme Court has already weighed in on the issue of regulatory jurisdiction over GHG emissions and concluded in

American Electric Power Co. v. Connecticut that such authority is vested in the EPA and the states.[18] The Court stated the following:

- "The critical point is that Congress delegated to EPA the decision whether and how to regulate carbon-dioxide emissions from power plants . . . ."
- "The appropriate amount of regulation in a particular greenhouse gas-producing sector requires informed assessment of competing interests. The Clean Air Act entrusts such complex balancing to EPA in the first instance, in combination with state regulators."

FLPMA Does Not Grant the BLM Jurisdiction to Promulgate Air Quality Standards

Section 108(a)(8) is a Non-Jurisdictional Policy Statement

As discussed above, the CAA prohibits the BLM from independently regulating air quality. However, certain commenters have asserted that Section 101(a)(8) of FLPMA nevertheless provides the BLM with broad and independent authority over air quality issues. Accordingly, we are also providing comments regarding the lack of BLM authority to pass air quality rules pursuant to FLPMA.

Section 101(a)(8) of FLPMA is very clearly a policy statement and is not a mandate or a jurisdictional grant—assertions that this provision provides the BLM with broad authority over air quality issues are either mistaken or a deliberate attempt to mislead. Properly quoted, Section 101(a)(8) states:[19]

> The Congress declares that it is the policy of the United States that . . . the public lands be managed in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values . . . .

To forestall any interpretations that the above language is no more than aspirational, Congress also stated that "[t]he policies of this Act shall become effective only as specific

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[18] 131 S. Ct. 2527 (2011). This case did not present an ideological split. The majority opinion was delivered by Justice Ginsburg, who was joined by Justices Roberts, Scalia, Kennedy, Breyer, and Kagan. Justice Alito filed a concurring opinion and was joined by Justice Thomas. Justice Sotomayor took no part in the consideration or decision of the case.

[19] 43 U.S.C. § 1701(a)(8). The BLM cites this provision in the "Authority" section of its Air Resource Management Program Manual, but properly notes that this language is a Congressional policy objective and does not explicitly state that this language confers a jurisdictional grant upon the agency.

statutory authority for their implementation is enacted by this Act or by subsequent legislation . . . ."[20]

Despite clear and express drafting by Congress, commenters often cite Section 101(a)(8) as a mandate, arguing that the BLM must manage the public lands in a manner that protects air and atmospheric values. For example, sixteen organizations made this exact assertion in a joint letter submitted to Secretary Sally Jewell in January 2014.[21]

FLPMA speaks for itself on this issue—the statute's policy goals are not a grant of regulatory authority. We comment here only to spotlight language (regarding policy) that is commonly omitted by others and to counteract the egregious mischaracterization of the statute as a Congressional mandate for BLM regulations concerning air quality.

FLPMA Requires Only that the BLM Provide for Compliance with Air Quality Regulations Promulgated by Other Federal Agencies and the States

Section 202(c)(8) is the only clear statutory command in FLPMA regarding air quality. It states that, when developing land use plans, the BLM must "provide for compliance with applicable pollution control laws, including State and Federal air, water, noise, or other pollution standards or implementation plans."[22]

This provision is clear evidence that Congress did not consider the BLM to be an air quality agency. Instead of directing that the BLM develop air emissions standards for federal lands, Congress simply required that the BLM condition land use approvals on compliance with the air quality standards and implementation plans developed by other federal agencies and the states.[23]

The above assessment is consistent with and reinforced by the conformity provisions and limited role for federal land managers established under the CAA Amendments of 1977, as previously discussed.

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[20] 43 U.S.C. § 1701(b).

[21] The letter faithfully reproduced the language in Section 101(a)(8), but omitted text from the beginning of Section 101(a) declaring the subsequent language to be policies. The letter is available at:

http://www.eenews.net/assets/2014/03/20/document_gw_01.pdf.

[22] 43 U.S.C. § 1712(c)(8).

[23] *See WildEarth Guardians v. Salazar*, 880 F. Supp. 2d 77, 94 (D.D.C. 2012) (concluding that the BLM satisfied its FLPMA obligations by preparing an oil and gas lease requiring compliance with air and water quality standards).

Normal Oil and Gas Emissions are Not Unnecessary or Undue Degradation ("UUD"); UUD is Determined on a Case-By-Case, Location-Specific Basis

As a final consideration, we note that FLPMA includes a requirement that, in managing the public lands, the Secretary shall "take any action necessary to prevent unnecessary or undue degradation of the lands."[24] When it comes to air quality, UUD must be read in conjunction with the CAA and Section 202(c)(8) of FLPMA as being applied on a case-by-case basis to ensure compliance with the air quality standards passed by the EPA and SIP provisions promulgated by the states.

For mining operations the BLM has defined UUD as including activities not "reasonably incident" to prospecting, mining, or processing operations.[25] Although UUD has not been defined for oil and gas exploration and production activities, the preceding definition indicates that impacts which are normal and typical are not UUD. In fact, this is the exact position adopted by the Interior Board of Land Appeals ("IBLA"). In *Biodiversity Conservation Alliance* (IBLA 2004-316, 2005-3), the IBLA recognized that the approval of oil and gas development does not constitute UUD and that UUD must be something more than the usual effects anticipated from such development.[26]

Regardless, how UUD applies to air emissions should be determined in the context of the CAA and the other provisions in FLPMA and the CAA. As discussed elsewhere, the CAA established an elaborate system of combined federal-state jurisdiction, but assigned federal land managers no more than an advisory role. We have also noted that there is only one clear statutory command in FLPMA regarding air quality and that provision limits the BLM's role to ensuring compliance with air quality requirements passed by other federal and state agencies.

In light of the preceding, it is difficult to imagine that Congress intended UUD (an undefined term) to provide the BLM with the authority to set nationwide air quality standards, much less standards different or more stringent than those established by the EPA and the states. In other words, to read such general language as giving the BLM extensive national air quality powers, powers that bypass the entire structure of the CAA, just doesn't make sense.

Lastly, we note that the multiple-use mandate imposed by FLPMA necessitates that, when it comes to air emissions, the BLM assess UUD issues on a case-by-case basis, and not as part of a nationwide rulemaking. For example, in a 2010 case concerning the scope of the BLM's

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[24] 43 U.S.C. § 1732(b).

[25] 43 CFR § 3809.5.

[26] 174 IBLA 1 (2008).

UUD obligations, the District Court for the District of Columbia held that "the BLM was not required, under FLPMA, to adopt the practices best suited to protecting wildlife, but instead to balance the protection of wildlife with the nation's immediate and long-term need for energy resources and the lessee's right to extract natural gas."[27]

The competing needs associated with various land parcels will vary from place to place, but this is especially the case for air quality, for which a nationwide system of air monitoring stations has been established and for which site-specific air dispersion modeling is commonplace in permit applications. This means that the BLM's assessment of air quality UUD issues, associated with the balancing of interests required by FLPMA, must be location specific and cannot provide the basis for a nationwide air quality rule.

Other Considerations and Comments

As previously noted, this comment letter is focused primarily on communicating our members' substantial jurisdictional concerns. However, we are also providing brief comments regarding several other significant issues. Because the list of issues discussed below are not exhaustive, IPAA is also fully endorsing the broader list of issues included in separate comments to be submitted by the AXPC.

"Best Practices" Must be Identified Based on Waste Prevention Criteria

The BLM's presentation materials note that NTL-4A no longer reflects best management practices and that the agency will consider Federal, tribal, and state rules and industry best practices as part of the venting and flaring public outreach process. These statements provide no insight into the criteria that the BLM will use to identify the new best practices that would be incorporated into a revised NTL-4A or a replacement rule.

Many of the venting and flaring practices currently required by EPA and state rules were identified and selected based on a cost-benefit analysis for the reduction of air pollutants, such as volatile organic compounds and hazardous air pollutants and not for waste minimization. These best practices for air quality control are not necessarily best practices for waste minimization.

The issue is that the metrics for pollution control are very different than the metrics for waste prevention. In the air quality world, best practices may result in a net cost of thousands or even tens of thousands of dollars per ton of emissions reduction and yet be

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[27] *Theodore Roosevelt Conservation Partnership v. Salazar*, 744 F. Supp. 2d 151, 157–58 (D.D.C. 2010). *See also Biodiversity Conservation Alliance v. BLM*, No. 09-CV-08-J (D. Wyo. 2010) (noting in the context of whether UUD obligations were met that the BLM is required to balance interests pursuant to its multiple use mandate).

deemed cost-effective. In contrast, the economic analysis for waste prevention is based on conservation of a valuable resource and therefore considers whether the prevention costs exceed the value gained—a net zero metric.

If the BLM proceeds with a rule proposal, best practices cannot be selected on grounds that they are already widely-employed because the very reason they have become commonplace is for purposes of air quality. Instead, the BLM must choose best practices based on an independent assessment of waste minimization principles, such as an analysis of the value of the resources preserved and the associated costs.

Infrastructure Expectations Should Not Change Over Time

The installation of additional infrastructure, which we understand to mean requirements to install gas collection pipelines, was included in the BLM's public outreach materials as one of the measures that could be included in a possible venting and flaring rule. These same materials note the possibility of periodic economic reevaluations.

As a result, our members are very concerned that the BLM will approve flaring during the early stages of field development, but may then revoke or deny renewal of those approvals and at some undetermined point require the shut-in of existing wells pending the permitting and installation of gas collection pipelines.

Oil and gas leasing, exploration, well drilling, and well completion involve very large capital expenditures. Accordingly, before drilling commences, operators need assurances that wells will not be shut-in and the associated capital will not be stranded. In addition, given the significant delays and difficulties in obtaining permits for infrastructure projects on public lands, shut-ins could last for several years. Due to time discounting, production delays would result in a net loss of value, even if the same volume of reserves were ultimately recovered.

If BLM rulemaking increases uncertainty with regard to the long-term viability of capital investments, many operators will reduce or eliminate their capital investments on federal lands. This would have the counterproductive effect of reducing production on federal lands and reducing net royalties received by the federal government, the states, and the tribes. Therefore, infrastructure requirements, if any, should not be retroactively imposed.

Streamlining Infrastructure Permitting Would More Effectively Meet the BLM's Goals

Regulatory obstacles to obtaining timely permits have significantly inhibited the construction of natural gas collection infrastructure, which in turn has resulted in flaring.

This phenomenon is particularly significant on federal lands, due to overly lengthy and arduous permitting requirements.

IPAA believes that a command-and-control rule that mandates controls and/or imposes one-size-fits-all venting and flaring restrictions is the wrong way to address venting and flaring, as it will dis-incentivize capital investments on public lands. Instead, we believe that efforts to streamline the siting, permitting, and construction of natural gas infrastructure on federal lands would better achieve the BLM's policy goals.

IPAA appreciates the opportunity to provide these comments regarding venting and flaring under NTL-4A. Please feel free to contact me at dnaatz@ipaa.org if you have any questions regarding the issues discussed herein.

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Can Natural Gas Save Lives? Evidence from the Deployment of a Fuel Delivery System in a Developing Country
Resul Cesur, Erdal Tekin, and Aydogan Ulker
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ABSTRACT

There has been a widespread displacement of coal by natural gas as space heating and cooking technology in Turkey in the last two decades, triggered by the deployment of natural gas networks. In this paper, we examine the impact of this development on mortality among adults and the elderly. Our research design exploits the variation in the timing of the deployment and the intensity of expansion of natural gas networks at the provincial level using data from 2001 to 2014. The results indicate that the expansion of natural gas services has caused significant reductions in both the adult and the elderly mortality rates. According to our point estimates, a one-percentage point increase in the rate of subscriptions to natural gas services would lower the overall mortality rate by 1.4 percent, the adult mortality rate by 1.9 percent, and the elderly mortality rate by 1.2 percent. These findings are supported by our auxiliary analysis, which demonstrates that the expansion of natural gas networks has indeed led to a significant improvement in air quality. Furthermore, we show that the mortality gains for both the adult and the elderly populations are primarily driven by reductions in cardio-respiratory deaths, which are more likely to be due to conditions caused or exacerbated by air pollution. Finally, our analysis does not reveal any important gender differences in the estimated relationship between the deployment of natural gas networks and mortality.

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I. Introduction

The recent emergence of natural gas as an abundant, efficient, and relatively inexpensive source of fuel has been transforming the world energy landscape. The new discoveries of large gas fields and technological innovations in drilling, such as hydraulic fracturing (aka fracking), are unlocking massive reserves of natural gas and threatening the position of coal as the dominant source of energy in many parts of the world. Natural gas is now the fastest-growing fossil fuel, with an annual growth rate of 1.9 percent, while coal is the slowest-growing fuel and is projected to be surpassed by natural gas by 2030 (U.S. Energy Information Administration, 2016). As a result of these developments, the average carbon intensity (CO_2 per unit of energy) of the global energy supply has started to decline as CO_2 emissions from the combustion of natural gas are about half as much as those from the burning of coal.[1] In fact, the combustion of natural gas results in much lower emissions of nearly all types of pollutants (Knittel et al., 2015).[2] Furthermore, natural gas requires limited processing to prepare it for end use, which makes it ideal for the purposes of domestic and commercial space heating. As a result of these qualities, some experts view the ongoing replacement of coal by natural gas as a positive development, which could be leveraged as a common sense approach to address the problem of global carbon emissions in the near- to mid-term, even if it cannot be the sole basis for efforts to achieving a completely renewable future long-term energy landscape (Brown et al., 2009; Center for Climate and Energy Solutions, 2013; Levi, 2013; Moniz et al., 2011).

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[1] It is important to note that total CO_2 emissions continue to rise despite the decrease in carbon intensity. But it is projected that the share of coal in overall fuel consumption would fall from 28 percent in 2012 to 22 percent in 2040, while that of natural gas would rise from 23 percent to 26 percent (U.S. Energy Information Administration, 2016).

[2] For example, natural gas virtually emits no sulfur oxides and particulates, and it releases about one-fifth of the nitrogen oxides released by coal. See http://www.c2es.org/energy/source/natural-gas.

While many developed countries have enacted environmental policies and regulations, and established effective monitoring systems to reduce carbon emissions, the progress in the developing world has been relatively stagnant because there are barriers to effective enforcement of regulations due to weak governance and corruption (Cesur et al., 2016; Greenstone and Hanna, 2014; Jayachandran, 2009). Environmental concerns are also overshadowed by the pressure that governments in these countries are facing in order to maintain robust economic growth. As a result, heavy reliance on coal continues and a full-scale transition to cost-effective, carbon-free energy alternatives are unlikely to develop in the near-term. Therefore, the potential for natural gas to mitigate climate change and reduce air pollution could particularly be a promising prospect for the developing countries.

Against this backdrop, an important question to consider is whether a technological development that led to a displacement of coal by natural gas would have an influence on public health. If natural gas indeed possesses the aforementioned qualities, then it is plausible to ask whether policies facilitating the expansion of natural gas infrastructure for commercial and residential applications translate into subsequent improvements in public health. This is a critically important question because ambient air pollution caused by carbon emissions is recognized as the most serious environmental risk to public health causing 3.7 million deaths worldwide – 6.7 percent of all deaths – annually.[3] It is estimated that about 16 percent of the lung cancer deaths, 11 percent of chronic obstructive pulmonary disease deaths, more than 20 percent of ischemic heart disease and stroke deaths, and about 13 percent of respiratory infection deaths are caused by air pollution. Therefore, it is important to understand whether the expanded use of natural gas as a replacement to coal could save some of these lives, at least until carbon-

[3] See http://www.who.int/gho/phe/outdoor_air_pollution/burden_text/en/.

frec energy alternativcs become widcly available. This paper seeks to inform this question by assessing the impact of a large scale deployment of natural gas networks on public health in the context of a developing country, namely Turkey. Turkey has begun investing in the development of a natural gas infrastructure in 1980s by expanding a grid of pipelines originating in its neighbours, including Azerbaijan, Iran, and Russia. These investments have led to a widesprcad displacement of coal by natural gas for residential and commercial space heating and cooking purposes. Today, 71 of the 81 Turkish provinces has a natural gas infrastructure in place. By exploiting the variation in the deployment of natural gas networks across Turkish provinces and over time, this study provides insights into the impact of displacement of coal by natural gas on adult and elderly mortality.

Despite all the attention paid to the natural gas revolution and its potentially profound implications for air pollution, the influence of a nationwide adoption of natural gas as the primary source of fuel on public health, particularly from the perspective of adults and the elderly is largely unknown. The only other investigation on this topic, Cesur et al. (2016), demonstrates that a widespread displacement of coal by natural gas had a significant reduction in infant mortality in Turkey. In the present study, we take the analysis in Cesur et al. (2016) a step further by examining the efficacy of the deployment of natural gas networks on mortality rates among adults and the elderly. This analysis is important because the potential role for governments to enhance social welfare by either funding the construction of pipelines or inducing household demand via subsidies requires a cost-benefit analysis that quantifies the public health benefits associated with displacing coal by natural gas for all age groups, not only infants. In this paper, we also assess whether any of the relationship between natural gas and mortality is gender or cause specific. There is epidemiological evidence to suggest that the health

risks posed by air pollution might differ by gender (e.g., Abbey et al.,1999; Chen et al., 2012; Clougherty, 2010; Dockery et al., 1993; Englert, 2004). Studies typically find effects that are stronger for females than males, although there is no consensus in the literature. It is also unclear to what extent these differing associations are attributable to socially-driven gender-specific differences (e.g., activity patterns, smoking prevalence, and exposure) versus biological differences (e.g., hormonal composition, reproductive organs, body size) (Clougherty, 2010; Krieger, 2003).

This paper also contributes to a small but growing literature on the impact of fuel transitions and adoption of new fuel technologies. Most of the existing evidence pertaining to the effects of natural gas related technology adoption comes from studies that consider the potential impact of fracking on public health outcomes of populations living near drilling sites (e.g., Adgate et al., 2014; Blamberger and Oswald, 2012; Colborn et al., 2012; Finkel and Hays, 2015; Finkel and Law, 2011; Hill, 2012; Howarth et al., 2011; Osborn et al., 2011; Tuller, 2015).[4] However, this effect is likely to be quite different from that of the displacement of coal by natural gas. First and foremost, studies on fracking raise concerns over the technique of extraction of natural gas and not over the choice between the combustion of natural gas versus coal. To the extent that any fracking-induced decrease in the price of natural gas might potentially cause a reduction in coal consumption and concurrently improve overall air quality, the net health effect associated with fracking could actually be positive. Until these positive externalities are fully considered, the debate over the net merit of fracking will not be settled. Second, natural gas considered in the current context does not pose the same environmental risks

[4] Evidence from these studies raise the possibility of a potentially negative health impact of fracking in relation to the chemicals used during the process, including seismic events, methane leaks, and underground water contamination. However, no consensus exists in the literature and there is a lack of credible evidence from well-designed investigations that properly account for confounding factors.

as in fracking because it is transmitted through pipelines that originate in wells located outside Turkey and drilled by the conventional vertical technique, which has a much smaller carbon print.

One exception to the fracking studies that is also relevant for the present paper is a recent analysis by Barreca et al. (2014), who examine the effects of bituminous coal consumption for home heating on infant and all age mortality rates in the United States during the mid-twentieth century. The authors show that the reductions in the consumption of coal between 1945 and 1960 significantly decreased both infant and all age mortality. The time frame considered in their analysis was also a period that coincides with a rapid switch away from coal towards oil and natural gas. This is important in terms of illustrating the potential role that a widespread displacement of coal by cleaner sources of fuel might have played on public health in the United States.[5] While the United States and many developed countries have made inroads towards cleaner fuels, the developing world continues to rely primarily on coal to meet its energy requirements.[6] We believe that it is important to identify and highlight the impact of socially desirable and economically viable public and market based approaches that would help natural gas gain traction as an alternative to coal in developing countries.

This papers also extends the literature on the impact of air pollution on the health outcomes of adults and the elderly. Research in economics and epidemiology has shown that exposure to air pollution has adverse effects on health by causing conditions such as pulmonary

[5] In particular, while the share of coal as a fuel for heating purposes declined from 55 to 35 percent, the share of natural gas increased by over 400 percent (see page 10 in Barreca et al., 2014).
[6] See for example, http://instituteforenergyresearch.org/analysis/coal-is-still-integral-to-many-countries-and-regions-in-the-world/.

and systemic inflammation, accelerated atherosclerosis, heart arrhythmias, and pneumonia.[7] One of the most notable contribution of economists in this field has been the improvement of empirical strategies to obtain causal estimates of the impact of exposure to air pollution, which is arguably endogenous. To highlight a few recent and notable examples, Chen et al. (2013) exploit the Huai River policy experiment in China to examine the impact of long-term exposure to air pollution on adult mortality. The authors first demonstrate that the policy, which provided free coal to citizens living to the north of the Huai River but not to the south, caused a substantial rise in total particulate matter (TSP) in the north relative to the south. They then show that the increase in TSP was accompanied with a significant increase in adult mortality in the affected regions due to the elevated rates of cardio-respiratory deaths. Anderson (2015) examines the impact of long-term exposure to air pollution on mortality by exploiting quasi-random variation in pollution levels generated by wind patterns near major highways in Los Angeles. He finds statistically and economically significant effects of downwind exposure to near-roadway pollution on mortality amongst the elderly. Finally, Schlenker and Walker (2015) exploit the variation in air pollution caused by runway traffic congestion in California airports to show that increased pollution levels in areas surrounding airports are associated with asthma, respiratory, and heart related hospitalizations among infants, adults, and elderly population.[8] It is important to note that all these three papers provide estimates for the health impact of a rise in air pollution, while the current paper considers the health effect of a development that results in a decrease in air pollution. This distinction is important because the relationship between air pollution and

[7] For example, see Anderson (2015), Barreca et al. (2014), Chen et al. (2013), DelFino et al. (2005), Dockery et al., 1993; Lockwood (2012), Pope et al. (2004), and Schlenker and Walker (2015).
[8] Both Chen et al. (2013) and Anderson (2015) focus on the health impact of long-term exposure to air pollution, Schlenker and Walker (2015) consider day-to-day fluctuations, which results in estimates for the short-run effect of air pollution on health rather than the long-run cumulative impact.

mortality needs not be symmetrical. This is especially likely to be true for an outcome like mortality that is irreversible. Furthermore, health problems caused by air pollution usually become chronic (e.g., heart and lung disease) and chronic conditions are not easily reversible when air quality is improved. Additionally, any health benefits attributable to improved air quality may be felt over time rather than being realized immediately, especially for adults and the elderly for whom most deaths are likely due to chronic conditions. In this paper, we recognize this issue by specifying a treatment variable that captures a dose-effect relationship rather a binary treatment approach adopted in most of the extant literature.

The research design in our study exploits the variation in the intensity of natural gas consumption, as measured by the number of subscribers to natural gas services per 100 persons, across Turkish provinces and over time. Our results indicate that the displacement of coal by natural gas induced by the deployment of natural gas networks has resulted in a significant improvement in air quality, which then caused mortality rate among adults and the elderly to decrease significantly. According to our point estimates, a one-percentage point increase in the intensity of natural gas consumption results in 1.9 and 1.2 percent decrease in the rates of mortality among adults and the elderly, respectively. Furthermore, these mortality gains appear to be almost exclusively driven by decreases in deaths due to cardio-respiratory conditions. This is not surprising since adult and elderly deaths are closely related to chronic disease conditions, which are likely to be exacerbated by air pollution. Finally, we find no evidence of meaningful differential effects between males and females.

II. Background

The developments that have led to the deployment of a natural gas infrastructure in Turkey have been discussed in detail in Cesur et al. (2016). Essentially, the rationale behind the country's decision to make massive investments on a network of natural gas pipelines was to diversify its energy portfolio and thereby reduce its vulnerability to global supply shortages in oil. Natural gas was identified as the most economically and technologically feasible candidate to add to its energy mix, given Turkey's close proximity to some of the world's largest natural gas producers such as Azerbaijan, Iran, and Russia. Importantly for the purpose of the present study, there is no evidence that improving public health was among the factors that played a role in the decision to deploy natural gas networks. First deployed in Ankara in 1988, natural gas networks spread gradually across Turkey over time and reached to 71 of the 81 provinces by 2014. Natural gas is imported from Azerbaijan, Iran, and Russia through pipelines that are operated by a state owned company called Botas.[9] The gas is then transmitted to individual provinces by privately owned distribution companies that are responsible for providing the public with clean burning natural gas by establishing and operating all infrastructural facilities for the utilization of natural gas.[10]

The deployment of natural gas networks has led to a rapid increase in the consumption of natural gas for domestic heating and cooking purposes, while the pace of increase in coal consumption has been much slower. For example, between the years of 2000 and 2010, the total consumption of coal and peat increased from 11 million tons of oil equivalent (Mtoe) to 14

[9] Over 60 percent of the natural gas used in Turkey is exported from Russia, which arrives in Turkey via two routes, first one coming through the Blue Stream pipeline that crosses the Black Sea and the other one traveling via the West Gas Pipeline through Bulgaria. The capacity of these two pipelines is about 30 billion cubic meters (bcm). Another pipeline with a capacity of 8.8 bcm is with Azerbaijan that travels through Georgia via the Baku-Tbilisi-Erzurum pipeline that was launched in 2007. The third connection is to Iran with a capacity of 10 bcm of natural gas. About 79 percent of natural gas imports are transmitted through pipelines, while the remaining 21 percent comes in liquefied form, mainly from Azerbaijan, Algeria, and Nigeria (International Energy Agency, 2011).

[10] For example, the companies in charge of distribution in the three largest provinces, Istanbul, Ankara, and Izmir are Igdas, Baskentgaz, and Izmirgaz, respectively.

Mtoe, while the natural gas consumption has nearly tripled from 4.9 Mtoe to 13.1 Mtoe. During the same period, the share of natural gas in electricity production increased from 37 percent to 46 percent, while the share of coal decreased from 31 percent to 26 percent.

Since both the construction and operation of natural gas infrastructure at the provincial level is handled by the private sector, the factors determining the timing and the rate of expansion of natural gas networks are typically associated with the economic viability of costly investments that are required to service provinces with natural gas. For example, the proximity to the main ports operated under the jurisdiction of the central government, the potential size of the market (i.e., the number of housing and commercial units or the population size), weather conditions such as the average duration of the heating season, and the conditions of the geographical terrain appear to be important factors (Aras and Aras, 2005; Cesur et al., 2016). Accordingly, it is no surprise that provinces such as Istanbul, Ankara, Bursa, and Eskisehir, that are either highly populated, located within close proximity to main pipelines, or with long and cold winters are among the early adopters, and provinces in remote regions with difficult access (e.g., Hakkari and Sirnak) or mild climates (e.g., Antalya, Aydin, and Mersin) are either late adopters or with no natural gas access yet.[11]

III. Data

Measures of Natural Gas

[11] Once a province is connected to a natural gas network, the decision about whether to switch from coal to natural gas depends on the type of housing unit occupied by the household. For example, the decision is voluntary for single family residential units. For residential buildings with multiple housing units, in which over 80 percent of all households reside, a simple majority decision among the residential units is required to make the change from coal to natural gas.

Data on natural gas have been obtained from the Turkish Natural Gas Journal (for the period 2001 to 2012) and the Turkish Energy Market Regulatory Authority (for years 2013 and 2014).[12] We construct measures that capture the deployment of natural gas networks both in the intensive and extensive margins. For the extensive margin, we create an indicator variable for whether natural gas networks are present and functioning in a province in each year between 2001 and 2014, and for the intensive margin we create an intensity measure representing the utilization rate of natural gas as measured by the number of individual subscribers per 100 persons.[13]

There is considerable variation in both extensive and intensive dimensions of deployment of natural gas. For example, only 5 of the 81 Turkish provinces had access to a natural gas network in 2001, but this figure has grown to 71 in 2014.[14] During the period of our analysis, the natural gas intensity has grown from 3.8 to 14.1 percent. However, the rate of expansion varies widely across provinces. For example, the subscription rate for natural gas services is over 30 percent in Ankara, Eskisehir, and Istanbul, suggesting that the coverage is near universal if one assumes between three to four individuals living per household.[15] But then Antalya – a province located on the Mediterranean coast with a warm climate – has a natural gas intensity of only 0.75 percent despite having a network in place since 2009.

[12] The Natural Gas Journal is published in Turkish under the name "Dogal Gaz Dergisi" and available at http://www.dogalgaz.com.tr/. It provides data on natural gas on an annual basis until the end of 2012. Note that for the period after 2012 the same data are also available from the Turkish Energy Market Regulatory Authority at http://www.epdk.org.tr/tr/anasayfa.

[13] An alternative approach could be to create the utilization rate per households instead of per persons. However, it is not possible to generate this figure for every year since province level household numbers are only available for 2000 and 2011. Following Cesur et al. (2016), we constructed an approximation to the number of households per province assuming a linear growth rate. Results from the analysis using this variable as the treatment measure did not change any of the implications of the results presented in this paper.

[14] Appendix Table 1 presents the list of provinces with natural gas infrastructure by 2014 along with the year of adoption and natural gas intensity in that year.

[15] The average household size in Turkey is 3.8 according to statistics from the Turkish Statistical Institute. See http://www.tuik.gov.tr/PreHaberBultenleri.do?id=15843.

Measures of Mortality

The data on mortality were obtained from the Turkish Statistical Institute (TurkStat) for the period between 2001-2014. We created age and gender specific mortality rates defined as the number of deaths per 1,000 persons present in each category. We consider mortality rates for males and females between ages 25 to 54 and ages 55 and older that represent the non-elderly adult and the elderly mortality rates, respectively.[16] As shown in Table 1A, the mortality rate averages about one per 1,000 persons among those aged 25-54 and jumps to about 18 per 1,000 for those aged 55 and older. Furthermore, the mortality rate is higher among males than females for both adults and the elderly. Figures in columns 2 to 5 of Table 1A reveal that mortality rates differ considerably between provinces with and without a natural gas network. For example, province-year observations with a natural gas network (column 3) has almost twice as high a mortality rate as those without one (column 2) regardless of age category and gender. A similar picture is drawn by columns 4 and 5, which show the means of mortality rates for provinces which did not gain access to a natural gas network at any time during the period of our analysis and those which did gain access to a network during the same period, respectively. The information illustrated in Table 1A may lead one to conclude that mortality rates may be directly related to natural gas. However, this would be misleading since it fails to account for potentially important factors that may be correlated with both the deployment of gas networks and public health at the provincial level. Below we elaborate more on some of the differences between provinces with and without natural gas network.

[16] Using alternative age cut-offs to define adult (e.g. 25 to 64) and elderly mortality rates (e.g., 65 and older) did not cause any appreciable changes to our main findings. Although the focus of this paper is adult and the elderly mortality, we also estimated models for infant mortality. The results from the analysis of infant mortality presented in Appendix Table 2, basically provides a reassurance of the findings in Cesur et al. (2016), which performed the same analysis using data for the period between 2001-2011. The results shown in Appendix Table 2 also reveal that there is no difference in the estimated relationship between natural gas and infant mortality between males and females.

Time-variant Provincial Characteristics

In our analysis, we account for a set of time-variant characteristics at the provincial level. These characteristics include number of hospitals and hospital beds per 100,000 persons, number of automobiles per 1,000 persons, number of physicians per 100,000 persons, an indicator variable for whether the province has a Family Physician Program in place, and an indicator variable for whether the elected mayor of the central district of the associated province has the same political affiliation with the political party governing Turkey.[17] We also account for differences in income per capita, unemployment rate, percentage of population holding a high school degree, percentage of population holding a college degree, and number of pupils per teacher in secondary schools at the sub-regional level.[18] The information pertaining to presence of the Family Physician Program comes from the Ministry of Health, while all other control variables are obtained from the TurkStat.[19] We also construct dummy variables that equal unity for observations with missing data on the explanatory variables.

Table 1B displays the means and standard deviations for these characteristics for the full sample as well as by breakdowns of the presence of a natural gas network. As shown in the table, provinces with and without a natural gas network differ from each other in a number of dimensions. For example, provinces with access to a natural gas network also have more

[17] Data on province populations are obtained from the TurkStat for years 2000 and 2007-2014 and from the Turkish Ministry of Health between 2001 and 2006. Since no Census was conducted between years 2001 and 2006, the province populations for the period of 2001-2006 are based on extrapolations implemented by the Ministry of Health. Alternatively, we imputed the population figures between 2001 and 2006 using province-specific growth rates. Using these values produce results that are nearly identical to those presented in this paper. These results are available from the authors upon request.

[18] These variables are only available at the sub-regional level. According to the TurkStat, Turkey is classified into 12 regions, 26 sub-regions, and 81 provinces. These regions and sub-regions are made up of clusters of provinces that are grouped together based on geographical proximity to each other and for statistical purposes.

[19] The Family Physician Program in Turkey, which was introduced in 2005, has extended basic healthcare services to the entire Turkish population under a free-of-charge and single-payer system that is fully financed and administered by the central government. Cesur et al. (2015) show that the program led to significant improvements in public health.

automobiles, higher income, a larger number of hospital beds and physicians, better educated populations, and a higher likelihood of having a Family Physician Program in place. These differences suggest that natural gas expansion is more likely in provinces that are wealthier, more urban, and with more educated populations. This is not surprising because the timing and intensity of deployment of a natural gas network may be positively associated with demand for natural gas services, which, in turn, is likely to be positively influenced by all these factors. Finally, provinces with natural gas are more likely to have a central district mayor who is affiliated with the ruling party. Again, this should not come as a surprise in a country where the decisions over resource allocation for local investment projects are controlled by the central government.

IV. Econometric Approach

Natural Gas and Air Pollution

In order for the deployment of natural gas networks to influence mortality, the displacement of natural gas by coal induced by these networks should lead to an improvement in air quality. There is already evidence, albeit descriptive, in support of a negative relationship between the expansion of the natural gas infrastructure and air pollution (Kaygusuz, 2007). In order to fortify this assumption with more concrete evidence and also to set the stage for our main analysis, we obtained data on province level yearly averages of particulate matter (PM_{10}) and sulfur dioxide (SO_2) from the Turkish Ministry of Health.[20] Then, we run regressions for each of these measures on natural gas intensity controlling for a vector of province characteristics along with province fixed effects, and region specific year dummies. The point

[20] Air pollution is measured by the provincial meteorology centres. The measurements are taken for a minimum of 21 days for each month for at least nine months.

estimates on the measure of natural gas intensity from these regressions are -0.057 for PM_{10} (p-value< 0.05) and -0.022 for SO_2 (p-value<0.01) suggesting that a one-percentage point increase in the intensity of natural gas results in 5.7 and 2.2 percent decreases in these two pollutants, respectively.[21] Furthermore, as indicated by p-values in parentheses the estimates are statistically significant at the 5- and 1-percent levels despite the significantly reduced sample sizes.[22]

Natural Gas and Mortality

In order to investigate the impact of natural gas networks on adult and the elderly mortality, we follow the strategy in Cesur et al. (2016) and begin with estimating models of the form:

$$\log(MR_{pt}) = X_{pt}\beta_o + \beta_1 NG_{pt} + \omega_p + \lambda_{rt} + \tau_p t + \tau_p t^2 + \varepsilon_{pt}, \qquad (1)$$

where MR_{pt} represents one of the mortality outcomes for province p in year t. X_{pt} is a set of exogenous determinants of mortality described above. The NG_{pt} is either a binary indicator for whether the province p has a natural gas network in place or the intensity of natural gas as measured by the number of subscribers to natural gas services per 100 persons in year t. The number of subscribers is the total number of household and business units with access to natural gas.[23]

[21] Note that data on SO_2 the PM_{10} is available only for a subset of the observations between 2001 and 2014 and for an unbalanced panel, which results in sample sizes of 772 and 766 year-province observations for SO_2 and PM_{10}, respectively. The coefficients on air pollution measures from a specification with province specific linear trends are imprecisely estimated likely due to reduced sample size.

[22] In the interest of space, we only mention the point estimates on natural gas intensity here, but full results are available from the authors upon request.

[23] Since our unit of analysis is at the provincial level, we are not able to separately identify the private and public health benefits associated with natural gas networks. However, by conducting the analysis at the provincial level, we

The causal interpretation of the coefficient β_1 is complicated due to confounding variables that are likely to be correlated with both the deployment of natural gas networks and mortality. In order to control for the impact of these factors, we rely on the longitudinal nature of our data and incorporate a series of fixed effects into equation (1). Specifically, the ω_p represents province fixed effects accounting for differences across provinces such as poverty, geographic terrain, and climate conditions, which are likely to remain time-invariant during our analysis period. Similarly, the λ_{rt} is a set of region-by-year fixed effects that would capture annual shocks to mortality at the regional level.[24] The region-by-year fixed effects would also account for time trends that are common across all provinces within a region.[25] The specification in equation (1) additionally allows for the trends in mortality rates to differ across provinces by accounting for province-specific linear and quadratic trends. These trends, denoted by the terms, $\tau_p t$ and $\tau_p t^2$, would capture the influence of difficult-to-measure time-varying differences or pre-existing trends across provinces as well as the differences in the rate of growth in natural gas intensity subsequent to the deployment of a natural gas network (Cesur et al., 2016).[26] They would

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are also able to avoid the difficulty of dealing with the endogeneity of individual decisions to switch from coal to natural gas. In that sense, our estimates should be interpreted as the combined effect of natural gas on those who benefit from improved air quality both privately and publicly (Cesur et al., 2016).

[24] As mentioned previously, regions in Turkey are clusters of provinces grouped together based on considerations of geographical proximity to each other and statistical purposes. There are 12 such regions. Since the province of Istanbul constitutes a region by itself, it is merged with the neighboring West Marmara region for computational simplicity when we constructed the region-by-year fixed effects. However, treating Istanbul as a separate region or dropping it from the sample produces nearly identical results. Note that year fixed effects are redundant once region-by-year fixed effects are included. Therefore, the latter would also gauge nationwide shocks to mortality.

[25] Regions have clusters of provinces, which share common characteristics that are likely to be correlated with mortality. Region-by-year fixed effects would account for these common factors. For example, East Marmara is a region with major urban and industrial provinces like Bursa, and Kocaeli. Furthermore, the heavier industrial activity in these provinces may have spillover effects on all the other provinces within the region that are not necessarily as industrial. For example, Bursa and Kocaeli are linked to each other through highly congested routes of transportation that have to pass through Yalova, a smaller and less urban province within the same region. Therefore, any air pollution, for example caused by the traffic congestion between Bursa and Kocaeli, may also affect the air quality in Yalova. Controlling for region-by-year fixed effects would also mitigate concerns about the aggregate impact of these factors.

[26] This application is similar to the one in Wolfers (2006), who examines the impact of unilateral divorce laws on divorce rates.

address the concern that changes in the access to natural gas over time might be correlated with broader changes in public-health conditions or convergence across provinces as well (Barreca et al., 2014). Finally, ε_{pt} represents a random error term. Standard errors are robust to any form of heteroscedasticity and serial correlation as they are clustered at the province level to allow for correlation within a province (Bertrand et al., 2004).

As mentioned above, equation (1) can be estimated by using either a binary treatment variable for the presence of a natural gas network or a continuous intensity measure, which captures the extent to which natural gas networks are utilized by the public within a province. In the former approach, the coefficient β_1 would measure any permanent shift in the rate of mortality associated with the deployment of a natural gas network averaged over the period in which a province has the network in place. This would be a measure independent of the actual level of the intensity of natural gas utilization in a province. However, the deployment of a natural gas network in a province and the adoption of natural gas by the residents of a province for space heating and cooking purposes are two separate processes. The latter is a process that evolves over time and one that depends on a number of factors including the relative price of coal to natural gas. In the end, it is the actual displacement of coal by natural gas that would have any bearing in terms of influencing public health. Unless the displacement rate of coal by natural gas reaches a critical level that would have an effect on air pollution, a binary treatment model would fail to register any impact on mortality even if all of the provinces have a natural gas network deployed, leading to the misleading conclusion that there is no association between natural gas and mortality.[27] This problem may be particularly severe in the current context,

[27] For instance, consider the extreme case where a province has natural gas available for its citizens as an alternative source of fuel, but nobody utilizes it. In this case, the effect of natural gas utilization on mortality should be zero, but a specification with a binary treatment measure would fail to reveal that.

where there is considerable variation in the intensity of treatment exposure across provinces and over time.

To see this more clearly, in Appendix Table 3 we present estimates of the impact of a binary indicator of natural gas on the rate of mortality using the specification expressed in equation (1). The first column presents the raw correlations between the natural gas indicator and the all age mortality rate (Panel A), mortality rate for those aged 25-54 (Panel B), and mortality rate for those aged 55 and older (Panel C), all in natural logarithms. As shown in the table, all of these correlations are positive and significant, and remain so even after controlling for region-by-year fixed effects. Only after accounting for permanent differences across provinces in column 3 do these estimates become negative as consistent with the notion that the displacement of coal by natural gas triggered by the deployment of natural gas networks had a mortality reducing influence. Moreover, the estimates change little in response to controlling for province specific linear and quadratic trends and time-varying characteristics of provinces. They are also small in size and statistically insignificant in these specifications.

In order to properly capture the dynamic nature of the treatment, we estimate equation (1) using the intensity measure of natural gas utilization. This specification recognizes the fact that the displacement of coal by natural gas is a process that occurs gradually and one that cannot be captured using a binary treatment model. The intensity specification is also more relevant from a public policy perspective when it comes to formulating policies to accomplish targeted levels of utilization of natural gas services. By employing a treatment measure that captures the extent to which natural gas services are deployed in a province, we essentially estimate a dose-effect relationship between natural gas networks and mortality. In this framework, the coefficient β_1 in

equation (1) using the continuous treatment measure would be interpreted as the impact of the rate of natural gas intensity on mortality.

Identification

There is no evidence to suggest that the rationale for the deployment of natural gas networks was to improve public health by reducing air pollution. Nevertheless, the descriptive statistics highlighted in Tables 1A and 1B clearly indicate that the pattern in which these networks have expanded over time and across provinces has not followed a random pattern either. As mentioned before, the provinces with natural gas networks are more likely to be urban, industrial, and with more motor vehicles per capita. Therefore, these provinces may also have higher mortality despite gaining access to a natural gas network. This can be further demonstrated by a simple analysis in which time-varying characteristics of provinces are regressed on a binary indicator for whether a province has a natural gas network in place. The results from this analysis are shown in Appendix Table 4. As shown in column 1, there are strong correlations between observable province characteristics and the natural gas indicator – a pattern that has already been established in Table 1B. As displayed in column 3 of Appendix Table 4, this pattern persists when we use the intensity measure instead. However, accounting for permanent differences across provinces via fixed effects also causes these differences to become much less nuanced, both in terms of size and statistical significance. Once we further control for confounding factors through province-specific linear and quadratic time trends as well as region-by-year fixed effects, none of the characteristics considered in this analysis are related to either of the natural gas measures (see columns 2 and 4). Importantly, none of the estimates reported in Appendix Table 4 are significant statistically or economically.

To gain further insights about the association between the deployment of natural gas networks and province characteristics, we next run regressions of the measures of natural gas on jointly specified time-varying factors listed in Table 1B. As shown in Appendix Table 5, the estimates from this analysis lend further support to the notion that any of the association between province characteristics and the pattern in which natural gas networks rolled out over time appears to be exogenous to public health, once we control for year and province fixed effects along with province-specific linear and quadratic trends, and region-by-year fixed effects. This conclusion is also supported by the F-statistics and the corresponding p-values reported at the bottom of columns 2 and 4 of Appendix Table 5, which clearly confirm the joint in-significance of all these characteristics. Taken together, the evidence from Appendix Tables 4 and 5 lends support to the notion that the provincial factors that might be associated with the pattern in which the natural gas networks are deployed become inconsequential once unobserved heterogeneity is accounted for. We interpret this as strong evidence that any remaining variation in the expansion of natural gas networks is plausibly exogenous to mortality outcomes (Cesur et al., 2016).

A relevant question to consider is whether there could be other province level policy developments that might be correlated with the deployment of natural gas networks. Alternatively, the deployment of natural gas networks could be part of a larger basket of investments or development projects implemented at the provincial level. We could not identify any such policy decisions that have been rolled out in conjunction with the deployment of natural gas networks. It is important to remember that the authority to enact laws and execute policies concerning energy and health are under the jurisdiction of the central government in Turkey. Consequently, many of these law changes or policies are implemented in all provinces

concurrently, and thus are accounted for by year fixed effects.[28] Furthermore, any differential investments by the central government at the provincial level should be captured by province-specific linear and quadratic time trends alongside with the indicator variable for whether the district mayor of the province is affiliated with the governing political party. Finally, region-by-year fixed effects would account for region specific unobserved heterogeneity such as any regional investments carried out by the central government in an effort to reduce economic and health disparities among regions.

If our identification strategy is valid, then natural gas networks should not have any impact on mortality in provinces prior to the deployment of these networks. A violation of this condition would suggest that any estimate of the relationship between natural gas networks and mortality may at least partially be spuriously driven by pre-existing differences between provinces with and without a natural gas network. A formal testing of this assumption can be performed by using an event-history analysis, which would enable us to trace out the trends in mortality rates year-by-year for the periods leading up to and following the deployment of a natural gas network (Cesur et al., 2016). In practice, we implement this analysis by augmenting equation (1) to include interactions between each of the year indicators with the binary indicator for the presence of a natural gas network. The event-history estimates from a specification that controls for province and region-by-year fixed effects are displayed in Figure 1 along with 95 percent confidence intervals. As shown in the figure, none of the interaction terms are

[28] It can also be argued that natural gas adoption and intensity may influence migration decisions of households between provinces with and without a natural gas infrastructure. The internal migration decisions are primarily determined by economic factors in Turkey and the flow of migration has been from rural to urban provinces in recent decades. To the extent that families migrating into provinces with natural gas are from low socio-economic status, our estimates would be a lower bound. Data on the proportion of migrants by province are available from the TurkStat only for the period 2008-2014. We estimated models of migration as a function of natural gas adoption and expansion along with other control variables. The coefficients on the two natural gas variables were both small and imprecisely estimated, suggesting that migration decisions are unrelated to natural gas. These results are available from the authors upon request.

statistically significantly different from zero in the years prior to deployment of a natural gas network in a province. It is assuring that there is no evidence of any systematic relationship between the treatment and mortality measures in those years. As also illustrated in Figure 1, there is a clear departure towards reduced mortality beginning with one year after the deployment of a natural gas network. Furthermore, the estimates on the interaction terms gradually become more negative over time, which is a pattern consistent with the notion that the presence of a natural gas network makes a difference in mortality only after the utilization of natural gas services becomes widespread enough to have an influence on air quality. In fact, the estimates on the interaction terms reach statistical significance only in the fourth year of deployment. Taken together, the evidence presented in Figure 1 supports the hypothesis that natural gas networks in Turkey had a causal negative effect on mortality.

V. Results

Table 2 presents the estimates of the impact of natural gas intensity from equation (1) on measures of mortality.[29] Panel A shows estimates for all age mortality, while Panels B and C show estimates for those aged 25-54 and 55 and older, respectively. In each panel, the first column displays estimates from a specification with no controls, followed by specifications that successively add region-by-year fixed effects, province fixed effects, linear and quadratic time trends, and time-varying covariates.

The estimates shown in the first column represent raw correlations between natural gas intensity and mortality. As illustrated before, these correlations are positively signed reflecting the non-random nature of the deployment of natural gas networks. Though less pronounced, the

[29] We also estimated weighted regressions using the mean population density and birth density as weights. These estimations, shown in Appendix Table 6, did not cause any appreciable changes to the results presented here.

same pattern persists in column 2 of Table 2 when region-by-year fixed effects are added to the specifications. This is also not surprising since region-by-year fixed effects only accounts for time-varying unobservables that are at the national or regional level. It is the pre-existing differences across provinces that are likely to be the source of endogeneity of natural gas networks. Accordingly, when we account for permanent differences across provinces via province fixed effects in column 3, the estimates switch sign and become negative as predicted. In addition to permanent differences, specification in column 3 further accounts for any time-varying differences across provinces that may be trending either linearly or quadratically. As mentioned earlier, these trends are also likely to account for the differences in the rate of increase in natural gas intensity in the post-deployment years of a natural gas network. Doing so causes the estimates on the natural gas intensity to decrease by two to three folds. According to the point estimates, a one-percentage point increase in the natural gas intensity as measured by the number of subscribers to natural gas services per 100 persons would reduce the all age mortality rate by 1.4 percent, the adult mortality rate by 1.9 percent and the elderly mortality rate by 1.2 percent.

It is important to note that controlling observed time-variant characteristics of provinces should not cause any appreciable changes to our estimates if our identification strategy is valid (i.e., the remaining variation in natural gas intensity is exogenous to health outcomes once the unobserved heterogeneity is captured by province fixed effects and province-specific time trends). As displayed in column 5 of Table 2, all three estimates on natural gas intensity remain unchanged. In particular, controlling for the eleven time-varying covariates listed in Table 1B causes no change in the estimates of the impact of natural gas intensity on mortality.

To put these point estimates into context, we next conduct several back of the envelope calculations for the number of lives saved as a result of the displacement of coal by natural gas. As illustrated in Table 1A, the average mortality rate for all ages in our province-year observations with a natural gas network is 5.18 per 1,000 individuals. Then, a point estimate of -0.014 translates into approximately 0.073 lives saved per every 1,000 persons in response to a one percentage-point increase in the intensity of natural gas. The total number of deaths in Turkey was about 391,000 in 2014. Therefore, approximately 5,460 lives might have been saved, had the intensity of natural gas been one-percentage point higher. Similarly, the approximate numbers of lives saved among the non-elderly adults and the elderly are 0.027 and 0.292 per 1,000 individuals in these age groups, respectively. Taking the total number of deaths in these age groups in 2014 as a base, these figures translate into a total of 846 lives saved among non-elderly adults and 3,851 lives saved among the elderly with respect to a one-percentage point increase in the intensity of natural gas. It is important to recognize that the number of lives saved among the elderly is much higher than that among the adults even though the percentage effect is greater for the adults than the elderly. This is not surprising because individuals aged 55 and older have a much higher baseline mortality and they are also more susceptible to health hazards of air pollution. For example, preexisting cardio-respiratory disorders are more common among the elderly than among the younger age groups.

Our empirical analysis essentially exploits the variation in the rate of displacement of coal by natural gas across provinces and over time. In other words, it is assumed that provinces in whieh the displacement takes place at a faster pace than other provinces should have mortality rates decreasing more rapidly in comparison to those of other provinces. In fact, this is the reason we refrain from using a binary treatment model as it would fail to capture the true

variation in natural gas utilization. If our assumption is valid, then we should also observe the impact of natural gas networks on mortality to increase over time as an increasing number of households switch from coal to natural gas. To test this, we estimate the impact of dichotomous indicators of the number of years since the adoption of natural gas network on measures of mortality. These results shown in Appendix Table 7 support the notion of a gradual but intensifying pattern in the hypothesized relationship between natural gas networks and mortality. More specifically, the point estimates, which are usually statistically significant, follow an increasing trend over time, i.e., the mortality gains associated with improved air quality are likely to be increasing over time. This is consistent with the notion that chronic health problems exacerbated by air pollution are not usually reversible easily. Another scenario that is consistent with the pattern obtained in Appendix Table 7 is that air pollution needs to be reduced below certain inflection points before significant mortality gains can be realized.

Finally, we subject the results shown in Table 2 to additional scrutiny by performing two robustness analyses. First, we test whether our results are sensitive to the exclusion of provinces that never gained access to a natural gas network during our analysis period. As shown in Appendix Table 8, estimating the model in equation (1) without these provinces produced estimates that are nearly identical to those in Table 2. Second, we exclude provinces that always had a natural gas network during the time period of our analysis. As presented in Appendix Table 9, these results are also indistinguishable from our main estimates. These analyses confirm that our main results are not driven by the possibility that there is something fundamentally different about those provinces.

Gender-Specific Analysis

To investigate the extent to which the relationship between natural gas intensity and mortality is gender-specific, we estimate equation (1) separately for males and females. As shown in Table 3, the evidence from this analysis yields no evidence of a clear distinction in the impact of natural gas intensity on mortality by gender. Focusing on the most comprehensive specification, the estimates are fairly close between males and females for all three age categories. This finding is similar to Chen et al. (2013) which examines the mortality and life expectancy consequences of air pollution using a policy experiment from China. Note that a failure to detect any gender differences in the relationship between natural gas intensity and mortality does not necessarily mean that the number of lives saved as a result of the deployment of natural gas networks is identical between males and females since mortality rates are higher for males than females regardless of age. For example, the point estimates from the analysis of all age mortality indicate that a one-percentage point increase in the intensity of natural gas results in 0.080 male lives saved per 1,000 males and 0.060 females lives saved per 1,000 females. The corresponding figures are 0.036 males and 0.002 females among those aged 25-54, and 0.607 males and 0.396 for females among those aged 55 and older.

Cause-Specific Analysis

Finally, we examine whether mortality effects of natural gas networks differ between deaths linked to cardio-respiratory causes and those linked to non-cardio-respiratory causes. The cause-specific analysis is useful because it is important to understand which health conditions are more responsive to improvements in air quality associated with the displacement of coal by natural gas. This knowledge is particularly helpful for the purpose of an accurate cost-benefit analysis associated with any public policies designed to increase the usage of natural gas

networks such as a subsidy because the cost of end-of-life care differs greatly across various health conditions. A cause-specific examination would also serve as a valuable specification analysis if the results reveal that estimates are stronger for the type of conditions that are more directly linked to ambient air pollution. A failure to find such a pattern would then cast serious doubts on our identification strategy, suggesting that the deployment of natural networks is correlated with other factors or developments associated with public health.

To answer these questions, we follow Chen et al. (2013) and classify deaths into two groups: cardio-respiratory deaths and non-cardio-respiratory deaths. The information used to categorize deaths into these two groups is obtained from the Causes of Death Statistics Database published by the TurkStat.[30] These statistics are based on underlying causes of deaths. We use the International Classification of Disease (ICD-10) codes for the evaluation of main cause of each death. The cardio-respiratory deaths are those that are linked to ambient air pollution and include heart disease, stroke, lung cancer, and respiratory illnesses. The non-cardio-respiratory deaths include those causes that are unlikely to be related, at least directly, to air pollution and include other cancers, accidental or violent deaths, various stomach ailments.

The results from this analysis are presented in Table 4. Focusing on the last column in Panel A of the table, the estimate on the impact of natural gas intensity on mortality is negative and statistically significant, suggesting that a one-percent increase in the intensity of natural gas results in a 0.9 percent decrease in cardio-respiratory mortality rate.[31] The point estimate is statistically significant at the five percent level despite likely measurement error in cause-specific

[30] See http://www.tuik.gov.tr/PreTablo.do?alt_id=1083.

[31] The Causes of Death Statistics Database covers all identifiable death cases detected by physicians from all localities including provinces and sub-district centers. In comparison with the all age mortality data used in previous estimations, it is less comprehensive particularly in years prior to 2009 and likely to suffer from measurement error to a larger degree. The smaller magnitude of the estimated effect of natural gas is likely to be due to such measurement error.

death classifications. Furthermore, as expected, the estimates for non-respiratory mortality shown in Panel B fail to reveal any impact of natural gas intensity on these deaths. In particular, the estimate from the most comprehensive specification is -0.004 and statistically indistinguishable from zero. In summary, these findings lend further support to our main hypothesis that the mortality gains caused by natural gas networks are attributable to reduced air pollution.

VI. Conclusions

In this paper, we examine the casual impact of the expansion of natural gas services for residential and commercial use on adult and elderly mortality in Turkey. The roll-out of natural gas networks has led to a widespread displacement of coal by natural gas as the primary source of fuel in Turkey. Given that natural gas is a much cleaner source of fossil fuel than coal, especially when it comes to concentrations of particulate matter, we assess whether any potential reductions in the carbon intensity in the atmosphere led to improvements in adult and elderly health as measured by their respective rates of mortality. To identify these impacts, we utilize the variation in the timing of deployment and intensity of expansion of natural gas networks across Turkish provinces between 2001 and 2014. Our results indicate that the expansion of natural gas services has led to a significant reduction in the rate of overall mortality as well as both adult and elderly mortality rates. The estimates from our most comprehensive specification indicate that a one-percentage point increase in the rate of subscriptions to natural gas services would cause the mortality rate to decrease by 1.4 percent (5,460 fewer deaths) among all age groups, 1.9 percent (848 fewer deaths) among adults, and 1.2 percent (3,851 fewer deaths) among the elderly. Furthermore, our analysis indicates that the mortality gains for both age groups are primarily

driven by cardio-respiratory deaths, which are more likely to be due to conditions caused or exacerbated by air pollution, such as pulmonary and systemic inflammation, accelerated atherosclerosis, heart arrhythmias, and pneumonia. Finally, our analysis does not reveal any important gender differences in the estimated relationship between the deployment of natural gas networks and mortality.

Taken together, our results highlight the health benefits of a nationwide transition towards a type of fuel that is gaining popularity due to its abundance, relatively lower cost, and higher efficiency. Due to challenges to getting developing countries to commit to legal obligations and the ineffectiveness of regulations due to poor governance and corruption, any meaningful reductions to carbon consumption in that part of the world, at least in the short-run, would likely come from actions or developments that are voluntary and, more importantly, in the economic interest of these countries. The findings of this paper suggest that the availability of large reserves of natural gas coupled with technological innovations in extraction and transmission in recent years has the potential to cause a real improvement in air quality and result in nontrivial improvements in public health.

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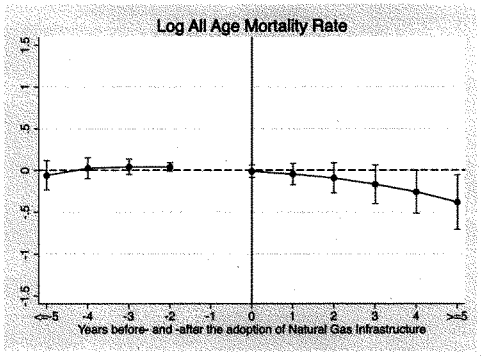
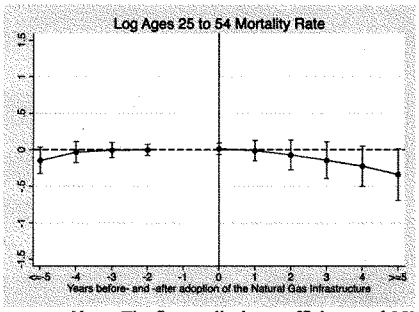
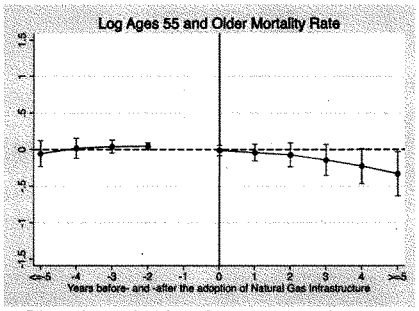
Figure 1
Event-History Estimates of the Impact of Any Natural Gas on Mortality Rate







Notes: The figures display coefficients and 95% confidence intervals. The reference category is one year prior to the deployment of a natural gas network.

Table 1A
Means of Natural Gas Variables and Mortality Indicators by "Any" and "Ever" Natural Gas Status

Variable	All	Any Natural Gas = 0	Any Natural Gas = 1	Ever Natural Gas = 0	Ever Natural Gas = 1
Any Natural Gas	0.44	--	--	--	0.51
	(0.50)	--	--	--	(0.50)
Natural Gas Intensity	3.90	--	8.89	--	4.52
	(7.07)	--	(8.33)	--	(7.42)
All Age Mortality Rate	3.62	2.40	5.18	2.74	3.76
	(2.21)	(1.72)	(1.74)	(2.57)	(2.12)
All Age Male Mortality Rate	3.95	2.59	5.68	2.91	4.12
	(2.45)	(1.89)	(1.93)	(2.80)	(2.35)
All Age Female Mortality Rate	3.29	2.21	4.68	2.58	3.40
	(1.99)	(1.56)	(1.57)	(2.36)	(1.90)
Ages 25 to 54 Mortality Rate	1.05	0.76	1.43	0.90	1.08
	(0.58)	(0.53)	(0.39)	(0.73)	(0.55)
Ages 25 to 54 Male 54 Mortality Rate	1.38	0.97	1.90	1.07	1.42
	(0.77)	(0.67)	(0.55)	(0.87)	(0.75)
Ages 25 to 54 Female Mortality Rate	0.72	0.55	0.94	0.71	0.72
	(0.42)	(0.43)	(0.28)	(0.64)	(0.37)
Ages 55 and Older Mortality Rate	17.90	12.88	24.32	14.80	18.39
	(8.86)	(7.66)	(5.54)	(10.95)	(8.39)
Ages 55 and Older Male Mortality Rate	20.48	14.76	27.80	17.02	21.03
	(10.17)	(8.80)	(6.44)	(12.37)	(9.68)
Ages 55 and Older Female Mortality Rate	15.69	11.29	21.32	12.94	16.12
	(7.79)	(6.77)	(4.84)	(9.84)	(7.33)
Infant Mortality Rate	8.59	6.85	10.78	7.01	8.83
	(5.37)	(5.66)	(4.05)	(6.32)	(5.18)
Infant Boy Mortality Rate	9.32	7.51	11.57	7.30	9.63
	(5.86)	(6.16)	(4.55)	(6.45)	(5.70)
Infant Girl Mortality Rate	8.07	6.47	10.02	7.18	8.20
	(5.06)	(5.34)	(3.90)	(6.57)	(4.79)
Observations	1134	636	498	154	980

Notes: Standard deviations are in parentheses.

Table 1B
Means of Control Variables by "Any" and "Ever" Natural Gas Status

Variable	All	Any Natural Gas = 0	Any Natural Gas = 1	Ever Natural Gas = 0	Ever Natural Gas = 1
Hospitals Per 100K Population	2.18	2.11	2.26	2.42	2.14
	(0.97)	(1.04)	(0.86)	(1.36)	(0.89)
Hospital Beds Per 100K Population	224.17	194.43	262.17	167.85	233.03
	(91.16)	(84.34)	(85.30)	(74.28)	(90.43)
Physicians Per 100K Population	122.68	100.53	150.97	84.64	128.66
	(50.97)	(38.60)	(50.88)	(31.78)	(50.85)
Family Medicine Program	0.43	0.19	0.75	0.41	0.44
	(0.50)	(0.39)	(0.44)	(0.49)	(0.50)
Unemployment Rate	9.82	10.21	9.49	10.14	9.76
	(3.92)	(4.37)	(3.47)	(4.57)	(3.81)
GDP Per Capita	8,996.01	7,032.44	1,1576.70	6,121.22	9,447.76
	(4,092.08)	(2,861.38)	(4,036.41)	(2,576.44)	(4,103.98)
Number of Vehicles Per Capita	0.16	0.12	0.21	0.08	0.17
	(0.09)	(0.07)	(0.07)	(0.05)	(0.08)
Percent High School	16.97	15.81	17.95	15.38	17.22
	(4.13)	(3.35)	(4.46)	(3.74)	(4.13)
Percent College	7.62	5.92	9.05	5.82	7.90
	(3.19)	(2.26)	(3.17)	(2.74)	(3.17)
Students Per Teacher	16.39	17.33	15.33	19.06	15.97
	(4.22)	(4.90)	(2.95)	(6.44)	(3.59)
Governing Party Mayor	0.56	0.48	0.67	0.36	0.60
	(0.50)	(0.50)	(0.47)	(0.48)	(0.49)
Observations	1134	636	498	154	980

Notes: Standard deviations are in parentheses.

Table 2
The Effect of Natural Gas Intensity on Adult Mortality

	(1)	(2)	(3)	(4)	(5)
Panel A: Log of All Age Mortality Rate					
Natural Gas Intensity	0.049***	0.010**	-0.038***	-0.014**	-0.014***
	(0.008)	(0.005)	(0.007)	(0.006)	(0.005)
Observations	1134	1134	1134	1134	1134
Panel B: Log of 25 to 54 Mortality Rate					
Natural Gas Intensity	0.041***	0.013***	-0.041***	-0.019***	-0.019***
	(0.005)	(0.004)	(0.008)	(0.007)	(0.006)
Observations	1134	1134	1134	1134	1134
Panel C: Log of 55 and Older Mortality Rate					
Natural Gas Intensity	0.040***	0.013***	-0.036***	-0.012**	-0.012**
	(0.005)	(0.002)	(0.006)	(0.005)	(0.005)
Observations	1134	1134	1134	1134	1134
Controls For					
Region by Year Fixed Effects	No	Yes	Yes	Yes	Yes
Province Fixed Effects	No	No	Yes	Yes	Yes
Province-specific Linear Trends	No	No	No	Yes	Yes
Province-specific Quadratic Trends	No	No	No	Yes	Yes
Time-varying Covariates	No	No	No	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Table 3
The Effect of Natural Gas Intensity on Adult Mortality by Gender

	(1)	(2)	(3)	(4)	(5)
Panel A: Log of All Age Mortality Rate					
			Males		
Natural Gas Intensity	0.050***	0.011**	-0.038***	-0.015**	-0.014***
	(0.008)	(0.005)	(0.007)	(0.006)	(0.005)
			Females		
Natural Gas Intensity	0.048***	0.009*	-0.039***	-0.014**	-0.013**
	(0.007)	(0.004)	(0.007)	(0.006)	(0.005)
Observations	1134	1134	1134	1134	1134
Panel B: Log of 25 to 54 Mortality Rate					
			Males		
Natural Gas Intensity	0.044***	0.013***	-0.041***	-0.019***	-0.019***
	(0.006)	(0.004)	(0.008)	(0.007)	(0.006)
			Females		
Natural Gas Intensity	0.038***	0.014***	-0.043***	-0.019**	-0.019**
	(0.005)	(0.004)	(0.009)	(0.008)	(0.007)
Observations	1134	1134	1134	1134	1134
Panel C: Log of 55 and Older Mortality Rate					
			Males		
Natural Gas Intensity	0.040***	0.013***	-0.035***	-0.013**	-0.013***
	(0.005)	(0.002)	(0.006)	(0.005)	(0.005)
			Females		
Natural Gas Intensity	0.041***	0.013***	-0.036***	-0.011**	-0.011**
	(0.005)	(0.002)	(0.006)	(0.005)	(0.005)
Observations	1134	1134	1134	1134	1134
Controls For					
Region-by-year Fixed Effects	No	Yes	Yes	Yes	Yes
Province Fixed Effects	No	No	Yes	Yes	Yes
Province-specific Linear Trends	No	No	No	Yes	Yes
Province-specific Quadratic Trends	No	No	No	Yes	Yes
Time-varying Covariates	No	No	No	No	No

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Table 4
The Effect of Natural Gas Intensity on Mortality by Cause of Death

	(1)	(2)	(3)	(4)	(5)
Panel A: Log of Cardio-respiratory Death Rate					
Natural Gas Intensity	0.044***	0.010*	-0.030***	-0.009**	-0.009**
	(0.007)	(0.006)	(0.006)	(0.005)	(0.004)
Observations	1134	1134	1134	1134	1134
Panel B: Log of Non-Cardio-respiratory Death Rate					
Natural Gas Intensity	0.073***	0.019***	-0.021***	-0.005	-0.004
	(0.010)	(0.005)	(0.005)	(0.004)	(0.004)
Observations	1134	1134	1134	1134	1134
Controls For					
Region by Year Fixed Effects	No	Yes	Yes	Yes	Yes
Province Fixed Effects	No	No	Yes	Yes	Yes
Province-specific Linear Trends	No	No	No	Yes	Yes
Province-specific Quadratic Trends	No	No	No	Yes	Yes
Time-varying Covariates	No	No	No	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Appendix Table 1
Natural Gas Adoption Year and Natural Gas Intensity in 2014 for Provinces with Natural Gas Infrastructure

Province	Adoption Year	Natural Gas Intensity in 2014	Province	Adoption Year	Natural Gas Intensity in 2014
Adana	2010	2.03	Karabuk	2009	17.18
Adiyaman	2010	7.07	Karaman	2009	12.76
Afyonkarahisar	2008	5.59	Kars	2009	4.62
Aksaray	2006	11.47	Kastamonu	2009	7.70
Amasya	2008	13.24	Kayseri	2005	18.80
Ankara	1988	30.94	Kilis	2013	2.95
Antalya	2009	0.75	Kirikkale	2007	20.26
Ardahan	2014	0.83	Kirklareli	2009	16.27
Aydin	2012	0.83	Kirsehir	2007	17.69
Balikesir	2005	11.33	Kocaeli	1996	25.03
Bartin	2014	1.81	Konya	2005	12.48
Batman	2012	4.02	Kutahya	2005	14.28
Bayburt	2009	10.97	Malatya	2007	14.56
Bilecik	2007	19.66	Manisa	2007	5.78
Bolu	2010	12.65	Mardin	2014	0.00
Burdur	2009	8.71	Mersin	2010	1.87
Bursa	1992	25.49	Mugla	2014	0.02
Canakkale	2007	12.37	Nevsehir	2009	10.88
Cankiri	2009	11.14	Nigde	2007	10.74
Corum	2005	15.24	Ordu	2009	4.81
Denizli	2007	13.15	Osmaniye	2011	2.47
Diyarbakir	2009	6.97	Rize	2009	8.13
Dnzce	2006	12.44	Sakarya	2005	14.88
Edirne	2009	9.26	Samsun	2006	12.01
Elazig	2009	14.85	Sanliurfa	2008	2.58
Erzincan	2009	12.32	Siirt	2012	3.86
Erzurum	2005	11.72	Sivas	2006	14.65
Eskisehir	1996	30.55	Tekirdag	2005	18.79
Gaziantep	2008	6.09	Tokat	2009	9.33
Giresun	2013	0.97	Trabzon	2010	3.42
Gumushane	2012	3.17	Usak	2006	12.36
Hatay	2010	1.57	Van	2008	2.91
Isparta	2009	11.72	Yalova	2006	26.71
Istanbul	1992	30.14	Yozgat	2007	9.09
Izmir	2007	8.42	Zonguldak	2006	6.69
Kahramanmaras	2007	6.39			

Notes: Provinces without natural gas infrastructure in 2014 are Agri, Artvin, Bingol, Bitlis, Hakkari, Igdir, Mus, Sinop Sirnak, and Tunceli. In Ankara, Bursa, Eskisehir, Istanbul, and Kocaeli natural gas infrastructure was developed prior to 2001. Natural gas intensity is expressed in per hundred populations.

Appendix Table 2
The Effect of Natural Gas Intensity on Infant Mortality

	(1)	(2)	(3)	(4)	(5)
Panel A: Total Sample					
Natural Gas Intensity	0.037***	0.021***	-0.060***	-0.029***	-0.029***
	(0.005)	(0.006)	(0.014)	(0.011)	(0.010)
Observations	1122	1122	1122	1122	1122
Panel B: Males					
Natural Gas Intensity	0.035***	0.021***	-0.061***	-0.027**	-0.028***
	(0.005)	(0.005)	(0.014)	(0.011)	(0.010)
Observations	1114	1114	1114	1114	1114
Panel C: Females					
Natural Gas Intensity	0.035***	0.022***	-0.065***	-0.028**	-0.027**
	(0.005)	(0.006)	(0.013)	(0.012)	(0.012)
Observations	1096	1096	1096	1096	1096
Controls For					
Region by Year Fixed Effects	No	Yes	Yes	Yes	Yes
Province Fixed Effects	No	No	Yes	Yes	Yes
Province-specific Linear Trends	No	No	No	Yes	Yes
Province-specific Quadratic Trends	No	No	No	Yes	Yes
Time-varying Province Characteristics	No	No	No	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Appendix Table 3
The Effect of Any Natural Gas on Adult Mortality

	(1)	(2)	(3)	(4)	(5)
Panel A: Log of All Age Mortality Rate					
Any Natural Gas	0.943***	0.215***	-0.086	-0.064	-0.069
	(0.056)	(0.062)	(0.075)	(0.051)	(0.047)
Panel B: Log of 25 to 54 Mortality Rate					
Any Natural Gas	0.812***	0.253***	-0.048	-0.046	-0.052
	(0.047)	(0.066)	(0.082)	(0.059)	(0.056)
Panel C: Log of 55 and Older Mortality Rate					
Any Natural Gas	0.777***	0.238***	-0.083	-0.065	-0.068
	(0.040)	(0.051)	(0.069)	(0.049)	(0.046)
Observations	1134	1134	1134	1134	1134
Controls For					
Region-by-year Fixed Effects	No	Yes	Yes	Yes	Yes
Province Fixed Effects	No	No	Yes	Yes	Yes
Province-specific Linear Trends	No	No	No	Yes	Yes
Province-specific Quadratic Trends	No	No	No	Yes	Yes
Time-varying Province Characteristics	No	No	No	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Appendix Table 4
Estimates of Time Varying Observable Province Characteristics on Natural Gas Indicators

	(1)	(2)	(3)	(4)
	Any Natural Gas		Natural Gas Intensity	
Dependent Variables				
Hospitals Per 100K Population	0.146	-0.023	0.003	-0.009
	(0.116)	(0.061)	(0.009)	(0.009)
	[1134]	[1134]	[1134]	[1134]
Hospital Beds Per 100K Population	67.740***	-1.997	4.183***	-0.312
	(9.291)	(3.878)	(0.915)	(0.506)
	[1134]	[1134]	[1134]	[1134]
Physicians Per 100K Population	50.448***	1.494	3.810***	-0.374
	(6.542)	(2.127)	(0.776)	(0.287)
	[1134]	[1134]	[1134]	[1134]
Family Medicine Program	0.553***	-0.031	0.029***	0.000
	(0.037)	(0.048)	(0.006)	(0.005)
	[1134]	[1134]	[1134]	[1134]
Unemployment Rate	-0.721	0.495	-0.045	-0.036
	(0.452)	(0.411)	(0.034)	(0.029)
	[891]	[891]	[891]	[891]
GDP Per Capita	4544.263***	-15.484	365.388***	-8.099
	(470.835)	(57.376)	(34.721)	(12.956)
	[648]	[648]	[648]	[648]
Number of Vehicles Per Capita	0.090***	0.001	0.005***	-0.000
	(0.008)	(0.002)	(0.001)	(0.000)
	[1134]	[1134]	[1134]	[1134]
Percent High School	2.147***	0.135	0.207***	-0.124
	(0.454)	(0.221)	(0.031)	(0.080)
	[891]	[891]	[891]	[891]
Percent College	3.129***	0.090	0.249***	-0.017
	(0.330)	(0.104)	(0.036)	(0.022)
	[891]	[891]	[891]	[891]
Students Per Teacher	-1.994***	0.121	-0.109**	0.025
	(0.569)	(0.257)	(0.043)	(0.026)
	[1053]	[1053]	[1053]	[1053]
Governing Party Mayor	0.182***	-0.009	0.012**	-0.009
	(0.054)	(0.080)	(0.005)	(0.006)
	[1134]	[1134]	[1134]	[1134]
Controls for				
Region by Year Fixed Effects	No	Yes	No	Yes
Province Fixed Effects	No	Yes	No	Yes
Province Linear and Quadratic Trends	No	Yes	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Number of observations is in brackets. Each coefficient, standard error, and number of observations trio pertains to a separate regression equation.

Appendix Table 5
Estimates of Natural Gas Indicators on Jointly Specified Time Varying Observable Province Characteristics

	(1)	(2)	(3)	(4)
	Any Natural Gas		Natural Gas Intensity	
Independent Variables				
Hospitals Per 100K Population	-0.033	-0.007	-0.260	-0.181
	(0.024)	(0.024)	(0.450)	(0.230)
Hospital Beds Per 100K Population	0.000	-0.000	-0.005	0.001
	(0.000)	(0.001)	(0.009)	(0.003)
Physicians Per 100K Population	0.001**	0.001	0.042***	-0.009
	(0.001)	(0.001)	(0.016)	(0.007)
Family Medicine Program	0.149***	-0.041	0.055	0.070
	(0.049)	(0.061)	(0.780)	(0.373)
Unemployment Rate	-0.004	0.003	-0.159**	-0.054
	(0.006)	(0.009)	(0.064)	(0.038)
GDP Per Capita	0.000***	0.000	0.001***	-0.000
	(0.000)	(0.000)	(0.000)	(0.000)
Number of Vehicles Per Capita	0.852**	0.943	-3.426	-10.658
	(0.422)	(1.739)	(5.668)	(10.961)
Percent High School	-0.005	0.002	0.044	-0.049
	(0.004)	(0.003)	(0.089)	(0.047)
Percent College	0.003	0.004	0.720***	0.011
	(0.009)	(0.008)	(0.193)	(0.064)
Students Per Teacher	0.012**	0.005	0.240**	0.008
	(0.006)	(0.006)	(0.100)	(0.036)
Governing Party Mayor	0.130***	-0.002	2.259**	-0.291
	(0.043)	(0.046)	(0.913)	(0.206)
Observations	1,134	1,134	1,134	1,134
R-squared	0.51	0.88	0.48	0.97
F-test	36.65	0.53	7.90	0.87
F-test P-value	0.00	0.88	0.00	0.57
Controls for				
Region by Year Fixed Effects	No	Yes	No	Yes
Province Fixed Effects	No	Yes	No	Yes
Province Linear and Quadratic Trends	No	Yes	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Each column pertains to a separate regression equation.

Appendix Table 6
The Effect of Natural Gas Intensity on Mortality, Population Density Weighted Regressions

	(1)	(2)	(3)	(4)
	Log Infant Mortality Rate	Log All Age Mortality Rate	Log Ages 25 to 54 Mortality Rate	Log Ages 55 and Older Mortality Rate
Natural Gas Intensity	-0.028***	-0.014***	-0.018***	-0.012**
	(0.010)	(0.005)	(0.006)	(0.005)
Observations	1,122	1,134	1,134	1,134
Controls For	Yes	Yes	Yes	Yes
Region-by-year Fixed Effects	Yes	Yes	Yes	Yes
Province Fixed Effects	Yes	Yes	Yes	Yes
Province-specific Linear Trends	Yes	Yes	Yes	Yes
Province-specific Quadratic Trends	Yes	Yes	Yes	Yes
Time-varying Province Characteristics	Yes	Yes	Yes	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Appendix Table 7
The Effect of Years Since Natural Gas Infrastructure Adoption on Mortality

	(1) Log Infant Mortality Rate	(2) Log All Age Mortality Rate	(3) Log Ages 25 to 54 Mortality Rate	(4) Log Ages 55 and Older Mortality Rate
Natural Gas Adoption Year	-0.183*	-0.083**	-0.071	-0.081**
	(0.106)	(0.041)	(0.048)	(0.041)
Natural Gas Year 2	-0.241*	-0.118*	-0.117	-0.119*
	(0.123)	(0.060)	(0.073)	(0.063)
Natural Gas Year 3	-0.288*	-0.156*	-0.188*	-0.150*
	(0.162)	(0.082)	(0.099)	(0.084)
Natural Gas Year 4	-0.377**	-0.180*	-0.234**	-0.174*
	(0.185)	(0.097)	(0.117)	(0.099)
Natural Gas Year 5+	-0.542**	-0.231*	-0.285**	-0.227*
	(0.246)	(0.120)	(0.143)	(0.119)
Observations	1,122	1,134	1,134	1,134
Controls For	Yes	Yes	Yes	Yes
Region-by-year Fixed Effects	Yes	Yes	Yes	Yes
Province Fixed Effects	Yes	Yes	Yes	Yes
Province-specific Linear Trends	Yes	Yes	Yes	Yes
Province-specific Quadratic Trends	Yes	Yes	Yes	Yes
Time-varying Covariates	Yes	Yes	Yes	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Appendix Table 8
The Effect of Natural Gas Intensity on Adult Mortality,
Excluding Provinces that Never Had Natural Gas Infrastructure

	(1)	(2)	(3)	(4)	(5)
Panel A: Log of All Age Mortality Rate					
Natural Gas Intensity	0.044***	0.009*	-0.027***	-0.010**	-0.010**
	(0.007)	(0.005)	(0.006)	(0.005)	(0.005)
Observations	980	980	980	980	980
Panel B: Log of 25 to 54 Mortality Rate					
Natural Gas Intensity	0.038***	0.014***	-0.029***	-0.014**	-0.013**
	(0.005)	(0.004)	(0.008)	(0.006)	(0.005)
Observations	980	980	980	980	980
Panel B: Log of 55 and Older Mortality Rate					
Natural Gas Intensity	0.038***	0.014***	-0.025***	-0.009*	-0.008*
	(0.005)	(0.002)	(0.006)	(0.004)	(0.004)
Observations	980	980	980	980	980
Controls For					
Region by Year Fixed Effects	No	Yes	Yes	Yes	Yes
Province Fixed Effects	No	No	Yes	Yes	Yes
Province-specific Linear Trends	No	No	No	Yes	Yes
Province-specific Quadratic Trends	No	No	No	Yes	Yes
Time-varying Covariates	No	No	No	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

Appendix Table 9
The Effect of Natural Gas Intensity on Adult Mortality,
Excluding Provinces that Always Had Natural Gas Infrastructure

	(1)	(2)	(3)	(4)	(5)
Panel A: Log of All Age Mortality Rate					
Natural Gas Intensity	0.078***	0.008**	-0.039***	-0.013**	-0.013**
	(0.009)	(0.004)	(0.008)	(0.006)	(0.005)
Observations	1064	1064	1064	1064	1064
Panel B: Log of 25 to 54 Mortality Rate					
Natural Gas Intensity	0.061***	0.001	-0.040***	-0.018**	-0.018***
	(0.007)	(0.002)	(0.009)	(0.007)	(0.007)
Observations	1064	1064	1064	1064	1064
Panel B: Log of 55 and Older Mortality Rate					
Natural Gas Intensity	0.061***	0.006***	-0.035***	-0.013**	-0.012**
	(0.006)	(0.002)	(0.007)	(0.005)	(0.005)
Observations	1064	1064	1064	1064	1064
Controls For					
Region by Year Fixed Effects	No	Yes	Yes	Yes	Yes
Province Fixed Effects	No	No	Yes	Yes	Yes
Province-specific Linear Trends	No	No	No	Yes	Yes
Province-specific Quadratic Trends	No	No	No	Yes	Yes
Time-varying Province Characteristics	No	No	No	No	Yes

Notes: Robust standard errors, clustered at the province level, are in parentheses. A *, **, or *** indicates significance at the 90%, 95%, or 99% levels, respectively. Time varying covariates include Hospitals Per 100K Population, Hospital Beds Per 100K Population, Physicians Per 100K Population, Family Medicine Program, Governing Party Mayor, and Number of Vehicles Per Capita at the province level, as well as Unemployment Rate, GDP Per Capita, Percent High School, Percent College, and Students Per Teacher at the sub-regional level.

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ENERGY BRIEF

The Shale Gas and Tight Oil Boom: U.S. States' Economic Gains and Vulnerabilities

Stephen P.A. Brown and Mine K. Yücel
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INTRODUCTION

U.S. policymakers have been concerned about the country's dependence on imported energy since World War II. Those concerns were highlighted in the 1970s when episodes of sharply rising oil prices led to recessions, economic stagnation, and high inflation. However, recent gains in U.S. oil and natural gas production are changing the dialogue about U.S. energy strengths and vulnerabilities.

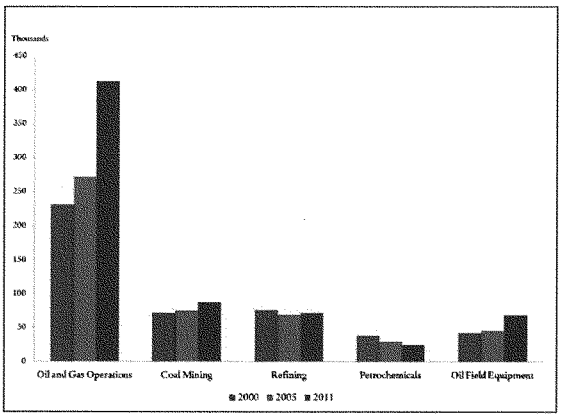
The "shale revolution" has stimulated tremendous production of oil and natural gas in the United States. The revolution is the product of advances in oil and natural gas production technology—notably, a new combination of horizontal drilling and hydraulic fracturing. These technological advances combined with high oil and gas prices have enabled increased production of the abundant oil and natural gas resources in the United States.

Greater availability of domestic energy resources benefits the United States by reducing dependence on imported energy and diversifying the economy.[1] But the boom also brings new vulnerabilities. Examining how changes in U.S. oil and natural gas production may affect individual state economies shows that some of the states providing new energy resources are becoming less economically diversified and more economically vulnerable to energy price declines.

OIL PRICES AND EMPLOYMENT IN THE U.S. FOSSIL FUEL INDUSTRY

Until recently, the U.S. oil and natural gas industry mostly followed the ups and downs of world oil prices, but with a long-term decline that reflected the decreasing availability of U.S. oil and natural gas resources. At the height of the early 1980s oil boom, the five industries most sensitive to oil prices—coal mining, oil and gas extraction, oil field machinery, petroleum refining, and petrochemicals—accounted for 1.6 million jobs, 1.8 percent of total U.S. nonagricultural employment.[2] By 2000, the share of these five industries had dwindled to 0.4 percent of total U.S. nonagricultural employment, only 457,000 jobs. With oil and natural gas prices rising beginning in the early 2000s, employment in the oil and natural gas sector began growing too. The boom in production of oil and natural gas from shale formations became a significant factor after 2008. Figure 1 shows that rising energy prices and the shale boom led to strong growth of U.S. oil and gas employment from 2005 to 2011.

Figure 1. U.S. Fossil Fuel–Related Employment



Sources: U.S. Bureau of Labor Statistics; author calculations.

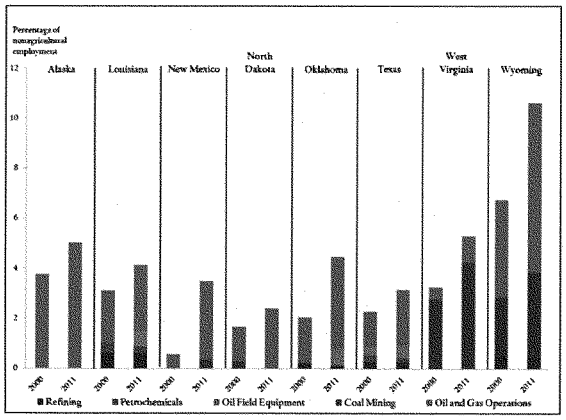
Despite recent gains, however, the fossil fuel industry has a smaller share of U.S. employment than it did in the early 1980s, and the industry's share of national economic activity is relatively small. After the end of the recession, between 2010 and the end of 2012, the industry added 169,000 jobs nationwide, growing at a rate about ten times that of overall U.S. employment. The industry's output shares follow a similar path. The share of oil and gas extraction was 4.3 percent of U.S. gross domestic product (GDP) at its height in 1981, but declined to 0.6 percent by 1999. The share of oil and gas rose to 1.6 percent of GDP in 2011 as a result of the shale boom.[3]

FOSSIL FUEL INDUSTRIES AND STATE EMPLOYMENT

As energy prices and U.S. oil and natural gas production fell from the mid-1980s to the early 2000s, most U.S. energy-producing states diversified away from energy production and energy-intensive industries. In 1982, the states with the greatest concentration of energy-related industries were West Virginia, Wyoming, Delaware, Oklahoma, Louisiana, and Texas.[4] Oil and natural gas accounted for much of the activity except in Delaware, which had a high concentration of the petrochemical industry, and in West Virginia, the heart of coal country. Shares of energy-related employment ranged from 7.3 percent in Texas to 13.7 percent in West Virginia. By 2000, these shares had declined to a range from 2.5 percent to 7.4 percent.

Rising oil and gas prices since the early 2000s prompted a resurgence of energy employment. Increased use of horizontal drilling and hydraulic fracturing led to further gains in oil and gas hiring. As of 2011, the states with the highest shares of energy employment were Alaska, Louisiana, New Mexico, North Dakota, Oklahoma, Texas, West Virginia, and Wyoming. As shown in Figure 2, energy employment shares increased in all eight of these states from 2000 to 2011.[5] Although there is little oil and gas activity in West Virginia, its coal production grew because coal prices followed the upward trend in oil prices in the 2000s. Despite these gains, however, almost every one of these states depends less on the five main energy-related industries than they did in 1982.

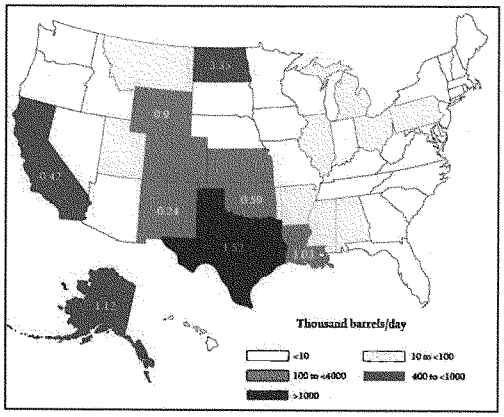
Figure 2. State Employment Shares



Sources: Author calculations with data from the U.S. Bureau of Labor Statistics.

Fossil fuel production has been important to these states' recent economic performance. Since the early days of the shale boom in 2006, the four states with the highest rates of employment growth are the states with the highest shares of oil and gas employment (Figure 3). The greatest growth has been in Texas and North Dakota, states with production from shale and the largest production increases. As seen in Figure 3, between 2006 and 2012, U.S. employment declined 0.05 percent per year on average, while employment in North Dakota and Texas grew by 3.4 and 1.5 percent, respectively, the fastest growth in the country.

Figure 3. Shale Oil and Employment Growth



Note: 2006–2012 yearly employment growth rates; U.S. average annual employment growth of -0.05.
Sources: Author calculations; data from U.S. Bureau of Labor Statistics; U.S. Energy Information Administration.

Because the United States is an oil importer, its economy has been hurt by previous episodes of sharply rising oil prices that resulted from oil supply shocks.[6] Given the oil production increase in the past couple of years, has the response of the U.S. economy to oil price shocks changed? The economic composition of individual states affects their responses to oil price shocks. We find that the economies of forty-two states and the District of Columbia would suffer if oil prices rise. In contrast, the economies of eight states—Alaska, Louisiana, New Mexico, North Dakota, Oklahoma, Texas, West Virginia, and Wyoming—would benefit from such increases.

To assess the effects of oil price shocks on states' economies, we first estimate the responses of individual industries to changes in oil prices using methods we used in a 1995 paper.[7] As shown in Table 1, the estimated price elasticity of total U.S. employment, based on data for 2000–2011, is -0.02, which means that a 10 percent increase in oil prices reduces U.S. employment by 0.2 percent.[8] Employment in the fossil fuel industries is considerably more responsive to oil price movements than employment in the overall economy is, but the responsiveness is less than we estimated eighteen years ago.[9] These differences are the result of changing relationships between the industries, such as the reduced sensitivity of coal and natural gas prices to oil prices, the closure of some U.S. refineries, and how relative changes in oil and natural gas prices affect the U.S. petrochemicals industry.

Table 1. Elasticities of Employment With Respect to Oil Prices[10]

	Elasticity
Total U.S. Employment	-0.02
Coal Mining	0.24
Oil and Natural Gas Extraction	0.40
Oil Field Machinery	0.29
Refining	-0.03
Petrochemicals	0.36

Sources: Author calculations.

To calculate the employment response of each state to an oil price shock, we combine these elasticities with the input-output analysis framework we previously developed and published in 1995 (updated with new multipliers).[11] The framework takes into account the composition of each state's economy, quantitative differences in multiplier effects across states, and the response of individual fossil fuel industries to changes in oil prices. Differences across the states in concentrations of energy-producing and energy-consuming industries account for most of the variation in the response of employment to oil price changes across the states. Differences in multiplier effects also account for some of the variation between states.[12]

The results show that a 25 percent increase in oil prices (for example from $100 to $125) would result in a loss of more than 550,000 jobs nationwide.[13] None of the states stand out as being hurt by rising oil prices by much more than the country as whole (Table 2). Several states without much of an oil and gas industry would see somewhat stronger negative effects from rising oil prices than the country as a whole.

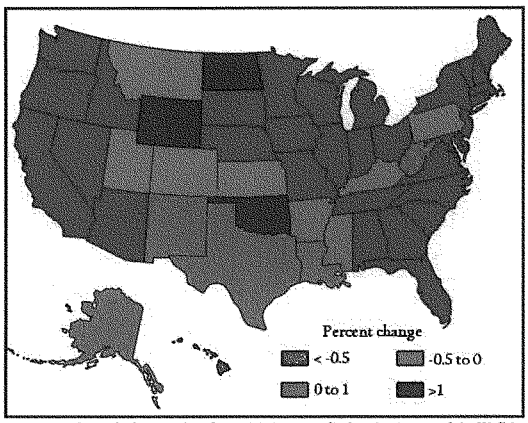
Table 2. Estimated Employment Response to a 25 Percent Increase in Crude Oil Prices, 2012

	Percent		Percent
United States	-0.43		
Wisconsin	-0.74	Ohio	-0.61
Minnesota	-0.73	Missouri	-0.60
Tennessee	-0.72	Illinois	-0.59
Rhode Island	-0.71	Massachusetts	-0.59
Florida	-0.71	Delaware	-0.58
New Hampshire	-0.70	South Dakota	-0.57
Idaho	-0.69	New York	-0.57
Nevada	-0.69	California	-0.56
Arizona	-0.68	Alabama	-0.56
Indiana	-0.68	District of Columbia	-0.50
Nebraska	-0.67	Kentucky	-0.48
Vermont	-0.66	Pennsylvania	-0.47
Iowa	-0.66	Utah	-0.38
New Jersey	-0.65	Kansas	-0.35
Washington	-0.64	Mississippi	-0.35
Maryland	-0.64	Arkansas	-0.34
Georgia	-0.64	Montana	-0.31
Michigan	-0.64	Colorado	-0.15
Virginia	-0.64	New Mexico	0.36
South Carolina	-0.64	West Virginia	0.36
Oregon	-0.64	Texas	0.60
Connecticut	-0.63	Louisiana	0.78
Maine	-0.62	Alaska	0.87
North Carolina	-0.62	North Dakota	1.01
Hawaii	-0.61	Oklahoma	1.16
		Wyoming	2.14

Sources: Author calculations; data from U.S. Bureau of Labor Statistics and the *Wall Street Journal*.

6

Figure 4. Estimated Employment Response to a 25 Percent Increase in Crude Oil Prices, 2012



Sources: Author calculations; data from U.S. Bureau of Labor Statistics and the *Wall Street Journal*.

Several states with larger fossil fuel industries see positive effects or a smaller negative effect than the country as a whole. Alaska, Louisiana, New Mexico, North Dakota, Oklahoma, Texas, West Virginia, and Wyoming would benefit from rising oil prices. Combined, these eight states would add around a hundred thousand jobs in response to a 25 percent rise in oil prices.

Wyoming would benefit most from an oil price spike because it has a small population and a large share of oil and gas extraction employment. Alaska's economy has traditionally depended on the oil extraction industry, has the second highest share of extraction employment among all states, and remains a beneficiary of higher oil prices. North Dakota's fossil fuel industry has grown rapidly since the onset of the shale boom and extraction is now 4 percent of state employment. West Virginia, with a strong coal industry, benefits from higher oil prices, but by less than what we previously estimated in 1995 for 1982 and 1992.[14] Coal prices moved together more tightly with oil prices until the global recession. Although coal prices have slowly trended higher during the recovery, the relationship with oil has weakened. As long as coal prices move with those for oil, the West Virginia economy will benefit from higher oil prices, albeit in a more muted manner than in the past.

The Louisiana and Texas economies are helped by rising oil prices, but employment response is less than in some energy states. These two states are home to 40 percent of U.S. refining capacity, and refining is hurt by rising oil prices. In addition, Texas has a large and diverse economy: the share of oil and gas extraction is about 2 percent of state employment, much less than in other energy-producing states.

Louisiana and Texas are also home to a substantial portion of U.S. petrochemical production. Rising oil prices help the U.S. petrochemicals industry as long as natural gas prices remain low. If enough domestic natural gas were exported such that U.S. natural gas prices again moved with oil prices, the U.S. petrochemicals industry would no longer benefit from rising oil prices.[15]

These employment responses differ substantially from those we previously estimated for 1982, a year at the height of the last U.S. oil and gas boom.[16] For that year, economies of thirteen states would have benefitted from rising oil prices. In addition to the eight states mentioned above, rising oil prices would have aided Colorado, Kansas, Montana, Mississippi, and Utah. Over the past thirty years, the economies in these five states have diversified away from crude oil production, and they no longer respond favorably to rising crude oil prices. Nonetheless, the presence of sizahle oil and natural gas industries in these five states mutes their negative response to rising oil prices.

7

STATE VULNERABILITY TO A DECLINE IN OIL PRICES

Increased energy prices and technological improvements were catalysts for the U.S. fossil fuel industry's turnaround. Would declining prices reverse those gains? A brief look at history is telling.

From 1972 to 1982, when oil prices increased more than tenfold, Texas economic output and employment averaged annual growth rates of 7.5 percent and 5.5 percent, respectively. When oil prices collapsed to about eleven dollars per barrel in 1986, the Texas economy went into a deep recession for two years. Economic output contracted 5.6 percent and employment fell 1.1 percent.

Even though oil and gas extraction accounted for 19 percent of the Texas economy in 1981, that share was the second smallest among the eight oil-sensitive states (West Virginia was smallest). As a percentage of state GDP, the oil and gas sector accounted for 49 percent in Alaska, 37 percent in Wyoming, 35 percent in Louisiana, and 20 percent in North Dakota. The 1986 oil price crash also caused a recession in most of these states, with employment declines largest in Wyoming (-5.9 percent) and Alaska (-4.5 percent)—states with the largest oil and gas output shares. The economies of these oil-sensitive states rebounded after 1987, but their growth rates were weaker than that of Texas.

Table 3 shows how the fossil fuel industry's output shares contracted after the oil industry peak in 1981 and later expanded with the shale boom, especially in North Dakota, Oklahoma, and Wyoming. The 2012 shares of state GDP from oil and gas extraction should prove even higher, given that oil production has been increasing in these states.[17] If oil prices were to collapse, these states with the highest concentrations in oil and gas extraction would be the hardest hit.

Table 3. Share of Oil and Gas Extraction in State GDP

	Percent		
	1981	**2000**	**2010**
Alaska	49.5	15.1	19.1
Louisiana	35.5	11.1	9.7
New Mexico	26.1	5.2	5.1
North Dakota	20.3	0.9	4.3
Oklahoma	21.6	4.8	9.1
Texas	19.1	5.8	7.8
West Virginia	2.4	1.0	1.5
Wyoming	37.1	9.8	18.5

Source: Author calculations; data from U.S. Bureau of Economic Analysis.

This finding is consistent with the results reported in Table 2. Applying our model in the same way for a price decline as for a price increase shows that falling oil prices would cause overall employment losses in Wyoming, Oklahoma, North Dakota, Alaska, Louisiana, Texas, West Virginia, and New Mexico, with the greatest percentage losses in the first three.[18]

States like Texas and Louisiana that have downstream oil and gas industries that benefit from falling energy prices such as refining and petrochemicals would be less affected. In addition, states in which natural gas is more prominent than oil are likely to see less harm from falling oil prices. With the recent weakening in the relationship between oil and natural gas prices, a decline in oil prices does not necessarily imply as big a change in natural gas prices as it once did, lessening the effect of an oil price decline.

While many states have diversified away from either a heavy reliance on energy consumption or energy production, others have seen and will continue seeing an increasing dependence on energy pro-

duction as a result of the shale revolution. Economic activity in these states is vulnerable to energy price declines. The smaller and less diversified the state, the larger the vulnerability. This vulnerability will increase with growing oil and natural gas production.

Yet most states that currently benefit from falling oil and gas prices will still gain from such developments even if their oil and gas production rises significantly in the coming years. For example, California, Colorado, and Pennsylvania produce a considerable amount of oil and natural gas, but these states would still gain from falling oil prices—even if their oil and gas sectors grew substantially. The California oil and gas sector, for example, would need to be more than 9.5 times larger than it is today for an oil price fall to hurt the California economy. Similarly, the sector would need to be more than 3.9 times larger in Pennsylvania and more than 1.3 times larger in Colorado for oil price declines to hurt the relevant state economies.

CONCLUSION

Given that oil is priced on an international market, increased domestic oil production will not do much to lower prices for U.S. consumers, as any gains in U.S. production will be spread across the international market. Greater reliance on domestic oil resources in substitution for imports will reduce the vulnerability of the economy to oil supply disruptions, although not by much.

Reduced energy use has lessened the vulnerability of the U.S. economy to oil price shocks. A similar phenomenon is seen at the state level, with many state economies having diversified away from energy-using industries. At the same time, the growing prominence of energy production can make states with small, undiversified economies more susceptible to an economic downturn during an energy price decline.

About the Authors

Stephen P.A. Brown is a professor of economics and the director of the Center for Business and Economic Research at the University of Nevada, Las Vegas. An internationally recognized scholar for his work in energy economics, Brown has conducted economic research and analysis on regional economic growth, aggregate economic activity, economic indicators, business conditions, public finance, energy, environment, climate policy, and economic impacts.

Mine K. Yücel is senior vice president and director of research at the Federal Reserve Bank of Dallas, where she has worked since 1989. Yücel analyzes the regional economy and energy markets on an ongoing basis and has published numerous articles on energy economics and regional growth. She has been the president of both the International and U.S. Association of Energy Economics and has served on the boards of numerous professional organizations.

The views expressed are those of the authors and should not be attributed to the Federal Reserve Bank of Dallas or the Federal Reserve System.

Endnotes

1. See Stephen P.A. Brown and Hillard G. Huntington, "Assessing the U.S. Oil Security Premium," *Energy Economics* vol. 38 no. C, July 2013, pp. 118–127; and Stephen P.A. Brown and Ryan T. Kennelly, "Consequences of U.S. Dependence on Foreign Oil," Center for Business and Economic Research, University of Nevada, Las Vegas, 2013.

2. U.S. Bureau of Labor Statistics.

3. U.S. sectoral GDP data come out with a lag. The latest data are from 2011.

4. See Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, Second Quarter, 1995.

5. Latest detailed state sectoral data are from 2011, as of this writing.

6. Lutz Kilian provides evidence that rising oil prices that result from demand shocks do not adversely affect U.S. economic activity. See Lutz Kilian, "Not All Oil Price Shocks Are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market," *American Economic Review* vol. 9 no. 4, June 2009, pp. 1053–1069.

7. Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, second quarter, 1995.

8. This estimate of the overall U.S. employment response is in the range of estimated GDP responses to oil price movements.

9. We previously estimated the oil-price elasticities of employment in coal mining, oil and natural gas extraction, oil field machinery, refining, and petrochemicals at 0.45, 1.01, 1.23, -0.56, and -0.32. See Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, second quarter, 1995.

10. The industry elasticities are obtained from regressions of sectoral employment on WTI crude oil prices, using monthly data for the time period 2000–2011. The total U.S. employment elasticity is taken from empirical work in the economics literature. See Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, second quarter, 1995.

11. Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, second quarter, 1995. We used the RIMS II multipliers for 2010 from the U.S. Bureau of Economic Analysis to update the analysis.

12. See Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, second quarter, 1995, for an exposition of the model.

13. Previous research on the response of U.S. economic activity to oil price shocks, such as James Hamilton's 2003 paper, finds the U.S. economy responds more strongly to oil price increases than oil price decreases. See James D. Hamilton, "What Is an Oil Shock?," *Journal of Econometrics* vol. 113 no. 2, April 2003, pp. 363–98.

14. Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, second quarter, 1995.

15. We showed in 2009 that there is coordinated movement in natural gas prices across the Atlantic, which can be accomplished through LNG shipments. But their results strongly suggest that the coordination of natural gas prices across the Atlantic is facilitated through oil prices, especially given that natural gas contracts in Europe are linked to oil prices. See Stephen P.A. Brown and Mine K. Yücel, "Market Arbitrage: European and North American Natural Gas Prices," *Energy Journal* vol. 30, special issue, 2009, pp. 167–185.

16. Stephen P.A. Brown and Mine K. Yücel, "Energy Prices and State Economic Performance," *Economic Review*, Federal Reserve Bank of Dallas, second quarter, 1995.

17. At the time of this writing, the most recent detailed GDP data for the states were from 2010.

18. Because the results for the energy-producing states are dominated by shifts within the fossil fuel industry, applying our model to oil price decreases creates only a slight upward bias to our estimates. That bias increases as we shift our attention toward energy-importing states.

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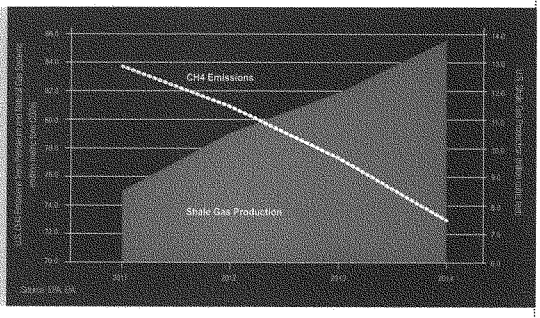
THE FACTS

ON NATURAL GAS PRODUCTION AND METHANE EMISSIONS

The oil and natural gas industry is substantially reducing methane emissions from oil and natural gas production and is expected to continue reducing emissions, according to the EPA. Methane emissions from the petroleum and natural gas systems sector have decreased by 13 percent since 2011, with the largest reductions coming from completions and workovers of hydraulically fractured natural gas wells, which have decreased by 83 percent during that period, according to the most recent EPA data. U.S. oil and natural gas companies are leading the charge to reduce emissions by making investments in new technology developed by the industry, and these efforts are paying off.

EPA Inventory of Greenhouse Gases

> **"The decrease in CH4 emissions is because of the large decrease in emissions from production and distribution. The decrease in production emissions is due to increased voluntary reductions..."**



U.S. EPA Administrator Gina McCarthy:
"Responsible development of natural gas is an important part of our work to curb climate change."

While some call for new government-directed efforts to reduce emissions, industry is pushing ahead—through its own leadership and investments—and is achieving strong results. **America is leading the world in producing natural gas and reducing greenhouse gas emissions and that is not an accident.**

America's oil and natural gas industry has a long-standing commitment to safety and protecting the environment. Between 2000 and 2014, the industry invested **$90 billion in greenhouse gas-mitigating technologies**. That's more than any other industry and nearly as much as the federal government ($110.3 billion). The industry invested $14.8 billion to develop domestic wind, solar, geothermal, biomass and other non-hydrocarbon resources between 2000 and 2014 – or one out of every six dollars invested in those areas.

U.S. Secretary of Energy Ernest Moniz:
"About half of that progress we have made on greenhouse gas emissions is from the natural gas boom."

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THE FACTS

ON NATURAL GAS PRODUCTION AND METHANE EMISSIONS

America's oil and natural gas industry is a leader in the effort to reduce **GHG emissions**. Even while our companies are leading a domestic energy renaissance, creating jobs and growing the economy, they're setting the pace for reducing emissions. **Economic growth** —spurred by increased domestic oil and natural gas development—and reducing carbon emissions need not be mutually exclusive. **The U.S. is near twenty year lows in energy related emissions—not from pursuing policies of "less" but "more."**

> [illegible]
> "Both global warming and air pollution can be mitigated by the development and utilization of shale gas"—therefore, "Environmentalists who oppose the development of shale gas and fracking are making a tragic mistake."

Oil and natural gas companies are energy companies. Oil and natural gas are the primary energy sources in this country and globally. But we should never forget the ongoing investments being made to find that next great breakthrough. We're major contributors in that effort, and as this study points out, we continue to improve our own emissions profile even as we provide more and more energy for the nation.

Unnecessary, and often duplicative, regulations are not necessary and could have **a chilling effect on the American energy** renaissance, which is, in fact, the goal for many of the groups calling for them.

> [illegible]
> "As we push to retire coal plants, we're going to work to make sure we're not simultaneously switching to natural-gas infrastructure. And we're going to be preventing new gas plants from being built wherever we can."

> [illegible]
> "I would say that I don't think the Environmental Defense Fund nor anyone in the environmental community who cares about this issue should be promoting the use of natural gas...I think we should be doing whatever we can to avoid excessive lock-in in new natural gas plants."

While regulation as a club may appeal to some environmentalists, it is the American people, our economy, and our national security that will take the blow. **The conversation about our energy future needs to be robust**, and **it needs to be fact-based.**

We welcome all to that discussion.

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Townhall
SEPTEMBER 8, 2016

EPA Methane Regulations Are Wasted Energy

Chip Knappenberger

1/17/2015 12:01:00 AM - Chip Knappenberger

Editor's note: Patrick J. Michaels coauthored this piece.

Newly announced EPA regulations targeting methane leakage are another part of President Obama's "Climate Action Plan," which more properly would be termed his "Climate Inaction Plan." The truth is, these new regulations will accomplish very little.

First of all, what is the breathless urgency here? The world is clearly not warming up as much as was forecast, this despite 2014 coming in as one of the warmest years ever recorded by the earth's scattered network of surface thermometers. In fact, during the past 18 years the earth's surface temperature has barely ticked up at all—rising at a rate some three time less than climate model projections. All the while the "worse than expected" claims attached to all manner of severe weather are being replaced by hard observations showing that "this isn't so bad after all."

That climate change will continue to be underwhelming and manageable is further supported by the growing body of scientific evidence that the Earth's surface temperature is considerably less sensitive to the build-up of greenhouse gas concentrations in the atmosphere than advertised by the U.N.'s Intergovernmental Panel on Climate Change, the U.S. Global Change Research Program and which is encapsulated in the President's executive actions on climate change.

Which brings us back to methane. According to the White House, the EPA is going to propose a new set of regulations aimed at reducing its emissions from the oil and gas sector by 40-45 percent by 2025, in the name cutting down on "wasted energy" and "addressing climate change" to "help ensure a cleaner, more stable environment for future generations."

Time to apply a little math to these propositions.

Methane emissions from oil and gas operations have been on the decline thanks to new and improved technologies that reduce methane leakage during drilling, pumping, and processing operations. Methane emissions from this sector have dropped more than 10 percent since 2008. The president is correct about this being "wasted energy"—because methane is in fact a natural gas, so it makes sense for the industry to try and capture more and more of what they sell.

Why do we need to force industry to do what it wants to do anyway?

On the environmental side, we're sold the canard that methane is about 25 times more efficient than carbon dioxide at enhancing the greenhouse effect on a molecule-by-molecule basis. Sounds like a big deal, no?

It's not. Carbon dioxide is measured in parts per million, methane in parts per *billion*. The difference between a million and a billion is 1000 million, making methane's allegedly more drastic effects inconsequential. Oil and gas methane comprises only about 3 percent of the total greenhouse effect changes coming from all US emissions.

So what would the President's proposed regulations do for global temperature?

Using the EPA's own policy model, it's easy to show that if the U.S. now and forever ceased emissions of *all* greenhouse gases, the amount of global warming that would be avoided would be about 0.15°C by the end of this century. Multiplying through the fact that the new regulations will reduce methane contribution from 3 percent down to 1.5 percent of this total, you can easily see that they will avert a whopping 0.002°C of global warming by century's end.

Coupling the ongoing downward emissions trajectory with the trifling climate impact makes the new EPA regulations on methane emissions senseless and unnecessary.

There's actually only one real reason for their announcement: to give the appearance of burnishing President Obama's climate change legacy and increasing his leverage during the year-end United Nations climate talks in Paris aimed at producing a "legally binding" international treaty limiting greenhouse gas emissions—a treaty which is not in our best interests and one which is most certainly destined to fail.

The Heritage Foundation

ISSUE BRIEF

No. 4341 | FEBRUARY 03, 2015

Methane Regulations Add to the Price Tag of the Administration's Climate Plan

Nicolas D. Loris

The Obama Administration recently announced plans to regulate methane emissions from the energy industry. The goal of the proposal is to cut methane emissions from the oil and gas sector 40 percent to 45 percent from 2012 levels by 2025.

The federal government's proposed methane regulation is yet another costly climate proposal that will drive up energy costs and drain resources already invested in reducing methane emissions, all the while yielding negligible, if any, climate benefits. Congress should use every legislative and budgetary tool in its arsenal to roll back the Administration's attack on affordable energy.

Are Methane Emissions Even a Problem?

Methane emissions in the United States present no human health or environmental threat. Indeed, the Occupational Safety and Health Administration (OSHA) does not list any exposure threshold for methane, nor does the agency list any long-term health effects.[1] As such, there is no health or environmental incentive behind the Administration's proposal to cut methane emissions from the oil and gas industry.

The purpose of the Administration's plan to reduce methane is the emissions' alleged impact on the climate. While methane is the second largest contributor to greenhouse gas emissions in the United States, methane still constitutes less than 9 percent of the U.S.'s total manmade greenhouse gas emissions. Methane is approximately 20 times more powerful of a greenhouse gas than carbon dioxide (over a 100-year period).[2] However, methane changes into carbon dioxide and water vapor in the atmosphere over time, so the warming impact depends on the time horizon.[3]

Globally, 60 percent of methane emissions are manmade, while 40 percent occur naturally.[4] In the United States, the single largest source of manmade emissions comes from enteric fermentation, or the digestive processes of livestock.[5] The next most predominant source is natural gas systems followed by landfills, coal mining, manure management, and petroleum systems. Wetlands cause nearly 80 percent of all naturally occurring methane output, followed by termites and leakage from the ocean surface.[6]

Free Markets Driving Methane Reduction

The Obama Administration's proposed methane regulations represent unnecessary government intervention to address a non-problem. Despite dramatic increases in natural gas production, methane emissions have been falling. According to the Environmental Protection Agency (EPA), emissions from natural gas systems have dropped 17 percent since 1990, and field production emissions have dropped 40 percent since 2006.[7] A 2014 University of Texas field study found that methane emissions from natural gas production and development comprise a meager 0.38 percent of total emissions, which is a 10 percent decrease from the previous year.[8]

This paper, in its entirety, can be found at **http://report.heritage.org/ib4341**

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The reason for declining methane emissions is simple. Energy producers have an incentive to capture and sell methane, the main component in natural gas, because it has valuable economic use for the production of electricity and heat. In fact, the EPA cites "voluntary reductions" as the primary reason emissions have fallen. According to Department of Energy Secretary Ernest Moniz, "More than half...of the current frack jobs are so-called 'green completions,' where the methane is captured and is [used] for economic benefit."[9] Investments in new drilling, extraction, and production technologies have increased productivity, lowered costs, and captured methane to sell. Institute for Energy Research President Thomas Pyle argued that implementing new methane regulations is like "issuing regulations forcing ice cream makers to spill less ice cream."[10] Clearly, the industry has every incentive to continue reductions without government intervention.

Despite the Administration's effort to build off the private sector's voluntary actions, federal regulations institute burdensome, complex processes that will likely slow the industry's current efforts to reduce emissions. Furthermore, regulations will result in additional compliance costs and force the industry to implement control technologies that are not profitable. Producers will then pass higher costs from those regulations onto families and businesses.

One Cog in a Costly Climate Plan

The proposed methane regulation is only one part of the Administration's climate plan, which taken as a whole, will drive up prices in the United States yet achieve no meaningful impact on global temperatures. The first step taken by the federal government is regulating greenhouse gas emissions from light and heavy duty vehicles. The bulk of the Administration's climate plan limits emissions from new aud existing power plants.

According to a Heritage Foundation study, these regulations will have damaging economic effects. Heritage Foundation economists modeled the effects of implementing a carbon tax equivalent to the Administration's social cost of carbon (SCC), which the EPA defines as the economic damage a ton of CO_2 emitted today will cause over the next 300 years.

To neutralize the analytical impacts of a tax's income transfer, The Heritage Foundation modeled a scenario in which 100 percent of carbon-tax revenue is returned to taxpayers. While the macroeconomic impacts of a regulatory scheme or a carbon tax should be broadly comparable, economists generally agree that, in practice, a carbon tax induces desired responses more efficiently than regulations.[11] Heritage analysis found that the U.S. economy would experience the following by 2030:

- An average employment shortfall of nearly 300,000 jobs;

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2. U.S. Environmental Protection Agency, "EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012," April 15, 2014, http://epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf (accessed January 30, 2014).
3. Gavin Schmidt, "Methane: A Scientific Journey from Obscurity to Climate Super-Stardom," National Aeronautics and Space Administration, September 2004, http://www.giss.nasa.gov/research/features/200409_methane/ (accessed January 30, 2015).
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11. For example, see Centre for Climate and Energy Solutions, "Options and Considerations for a Federal Carbon Tax," February 28, 2013, http://www.c2es.org/docUploads/options-considerations-federal-carbon-tax.pdf (accessed January 30, 2015).

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FEBRUARY 03, 2015

- A peak employment shortfall of more than 1 million jobs;
- 500,000 jobs lost in manufacturing;
- An aggregate gross domestic product loss of more than $2.5 trillion (inflation-adjusted); and
- A total income loss of more than $7,000 per person (inflation-adjusted).[12]

To make matters worse, the climate impact of the government's climate plan will be almost too small to measure.[13]

Opportunity for Congress to Lead

In the most recent State of the Union address, President Barack Obama affirmed he would not let "Congress endanger the health of our children by turning back the clock on our efforts" on climate change.[14] Enacting climate regulations, however, will have no impact on the health of our children and our environment. In fact, the proposed climate regulations are endangering future generations by promising a world with less prosperity and opportunity.

Congress should do everything in its power to stop these regulations, including prohibiting any federal government agency from regulating methane, carbon dioxide, and other greenhouse gas emissions; using the Congressional Review Act when applicable to stop any final regulations; and using its budgetary authority to strip funding for the promulgation and enforcement of climate regulations.

*—**Nicolas D. Loris** is Herbert and Joyce Morgan Fellow in the Thomas A. Roe Institute for Economic Policy Studies, of the Institute for Economic Freedom and Opportunity, at The Heritage Foundation.*

12. Kevin D. Dayaratna et al., "The Obama Administration's Climate Agenda: Underestimated Costs and Exaggerated Benefits," Heritage Foundation *Backgrounder* No. 2975, November 13, 2014, http://www.heritage.org/research/reports/2014/11/the-obama-administrations-climate-agenda-underestimated-costs-and-exaggerated-benefits#_ftn16.
13. Patrick Michaels and Paul C. "Chip" Knappenberger, "Fuel Efficiency Standards for New Trucks—Can't We Decide These for Ourselves?" Cato Institute, February 19, 2014, http://www.cato.org/blog/fuel-efficiency-standards-new-trucks-cant-we-decide-these-ourselves (accessed January 23, 2015).
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UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Independent Petroleum Association of America, American Exploration & Production Council, Domestic Energy Producers Alliance, Eastern Kansas Oil & Gas Association, Illinois Oil & Gas Association, Independent Oil and Gas Association of West Virginia, Inc., Indiana Oil and Gas Association, International Association of Drilling Contractors, Kansas Independent Oil & Gas Association, Kentucky Oil & Gas Association, Michigan Oil and Gas Association, National Stripper Well Association, North Dakota Petroleum Council, Ohio Oil and Gas Association, Oklahoma Independent Petroleum Association, Pennsylvania Independent Oil & Gas Association, Texas Alliance of Energy Producers, Texas Independent Producers & Royalty Owners Association, and West Virginia Oil and Natural Gas Association, Petitioners, v. United States Environmental Protection Agency, Respondent.	CASE NO.

PETITION FOR REVIEW

Pursuant to Section 307(b)(1) of the federal Clean Air Act ("CAA"), 42 U.S.C. § 7607(b)(1), the Independent Petroleum Association of America ("IPAA"), American Exploration & Production Council ("AXPC"), Domestic Energy Producers Alliance ("DEPA"), Eastern Kansas Oil & Gas Association ("EKOGA"), Illinois Oil & Gas Association ("IOGA"), Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), Indiana Oil and Gas Association ("INOGA"), International Association of Drilling Contractors ("IADC"), Kansas Independent Oil & Gas Association ("KIOGA"), Kentucky Oil & Gas Association ("KOGA"), Michigan Oil and Gas Association ("MOGA"), National Stripper Well Association ("NSWA"), North Dakota Petroleum Council ("NDPC"), Ohio Oil and Gas Association ("OOGA"), Oklahoma Independent Petroleum Association ("OIPA"), Pennsylvania Independent Oil & Gas Association ("PIOGA"), Texas Alliance of Energy Producers ("Texas Alliance"), Texas Independent Products & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers"), hereby petition this Court for review of final agency action that respondent United States Environmental Protection Agency took under Sections 111(b)(1)(B) and 112(d)(2) of the CAA, 42 U.S.C. §§ 7411(b)(1)(B) and 7412(d), entitled "Oil and Natural Gas Sector: Emission Standards for New,

Reconstructed, and Modified Sources," 81 Fed. Reg. 35824 (June 3, 2016) (the "Oil and Natural Gas NSPS").

The Independent Producers participated in comments on the proposed Oil and Natural Gas NSPS either in their individual capacity or as a member of IPAA, or both.

Respectfully Submitted,

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Royalty Owners Association, and West Virginia Oil and Natural Gas Association

Dated: August 1, 2016

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Independent Petroleum Association of America, American Exploration & Production Council, Domestic Energy Producers Alliance, Eastern Kansas Oil & Gas Association, Illinois Oil & Gas Association, Independent Oil and Gas Association of West Virginia, Inc., Indiana Oil and Gas Association, International Association of Drilling Contractors, Kansas Independent Oil & Gas Association, Kentucky Oil & Gas Association, Michigan Oil and Gas Association, National Stripper Well Association, North Dakota Petroleum Council, Ohio Oil and Gas Association, Oklahoma Independent Petroleum Association, Pennsylvania Independent Oil & Gas Association, Texas Alliance of Energy Producers, Texas Independent Producers & Royalty Owners Association, and West Virginia Oil and Natural Gas Association, Petitioners, v. United States Environmental Protection Agency, Respondent.	CASE NO.

RULE 26.1 DISCLOSURE STATEMENT OF THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA, AMERICAN EXPLORATION & PRODUCTION COUNCIL, DOMESTIC ENERGY PRODUCERS ALLIANCE, EASTERN KANSAS OIL & GAS ASSOCIATION, ILLINOIS OIL & GAS ASSOCIATION, INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA, INC., INDIANA OIL AND GAS ASSOCIATION, INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS, KANSAS INDEPENDENT OIL & GAS ASSOCIATION, KENTUCKY OIL & GAS ASSOCIATION, MICHIGAN OIL AND GAS ASSOCIATION, NATIONAL STRIPPER WELL ASSOCIATION, NORTH DAKOTA PETROLEUM COUNCIL, OHIO OIL AND GAS ASSOCIATION, OKLAHOMA INDEPENDENT PETROLEUM ASSOCIATION , PENNSYLVANIA INDEPENDENT OIL & GAS ASSOCIATION, TEXAS ALLIANCE OF ENERGY PRODUCERS, TEXAS INDEPENDENT PRODUCERS & ROYALTY OWNERS ASSOCIATION, AND WEST VIRGINIA OIL AND NATURAL GAS ASSOCIATION

Pursuant to Fed. R. App. P. 26.1 and D.C. Circuit Rule 26.1, Petitioners, the Independent Petroleum Association of America, American Exploration & Production Council, Domestic Energy Producers Alliance, Eastern Kansas Oil & Gas Association, Illinois Oil & Gas Association, Independent Oil and Gas Association of West Virginia, Inc., Indiana Oil and Gas Association, International Association of Drilling Contractors, Kansas Independent Oil & Gas Association, Kentucky Oil & Gas Association, Michigan Oil and Gas Association, National Stripper Well Association, North Dakota Petroleum Council, Ohio Oil and Gas Association, Oklahoma Independent Petroleum Association, Pennsylvania Independent Oil & Gas Association, Texas Alliance of Energy Producers, Texas Independent Producers & Royalty Owners Association, and West Virginia Oil and

Natural Gas Association (collectively, "Independent Producers") file the following statement:

The Independent Petroleum Association of America ("IPAA") is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies. IPAA has no parent corporation and there is no publicly held corporation that owns 10% or more of its stock.

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

gas, both offshore and onshore, from non-conventional sources in environmentally responsible ways. AXPC has no parent corporation and there is no publicly-held corporation that owns more than 10% of its stock.

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The Texas Alliance of Energy Producers ("Texas Alliance") became a statewide organization in 2000 with the merger of two of the oldest oil & gas associations in the nation: the North Texas Oil & Gas Association and the West Central Texas Oil & Gas Association. The Texas Alliance is now the largest statewide oil and gas association in the country representing Independents. With

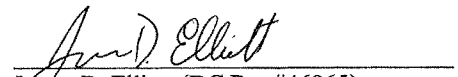
members in 34 states, the Texas Alliance works on behalf of our members at the local, state, and federal levels on issues vital to the industry. The Texas Alliance is a non-profit entity, has no parent corporation, and there is no publicly held corporation that owns 10% or more of its stock.

The Texas Independent Producers & Royalty Owners Association ("TIPRO") is a trade association representing the interests of 3,000 independent oil and natural gas producers and royalty owners throughout Texas. As one of the nation's largest statewide associations representing both independent producers and royalty owners, members include small family businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and trusts. Members of TIPRO are responsible for producing more than 85 percent of the natural gas and 70 percent of the oil within Texas, and own mineral interests in millions of acres across the state. TIPRO has no parent corporation and there is no publicly-held corporation that owns more than 10% of its stock.

Chartered in 1915, the West Virginia Oil and Natural Gas Association ("WVONGA") is one of the oldest trade organizations in the State, and is the only association that serves the entire oil and gas industry. The activities of our members include construction, environmental services, drilling, completion, gathering, transporting, distribution, and processing. WVONGA has no parent

corporation and there is no publicly held corporation that owns 10% or more of its stock.

Respectfully Submitted,



James D. Elliott (DC Bar #46965)
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Counsel for the Independent Petroleum Association of America, American Exploration & Production Council, Domestic Energy Producers Alliance, Eastern Kansas Oil & Gas Association, Illinois Oil & Gas Association, Independent Oil and Gas Association of West Virginia, Inc., Indiana Oil and Gas Association, International Association of Drilling Contractors, Kansas Independent Oil & Gas Association, Kentucky Oil & Gas Association, Michigan Oil and Gas Association, National Stripper Well Association, North Dakota Petroleum Council, Ohio Oil and Gas Association, Oklahoma Independent Petroleum Association, Pennsylvania Independent Oil & Gas Association, Texas Alliance of Energy Producers, Texas Independent Producers & Royalty Owners Association, and West Virginia Oil and Natural Gas Association

Dated: August 1, 2016

Interstate Natural Gas Association of America

April 27, 2016

Via email

U.S. Environmental Protection Agency
EPA Docket Center
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

RE: Supplemental Comments Filed in Response to "Oil and Gas Sector: Emission Standards for New and Modified Sources" Proposed Rule, Docket No. EPA-HQ-OAR-2010-0505.

Dear Docket Clerk:

The Interstate Natural Gas Association of America (INGAA), a trade association of the interstate natural gas pipeline industry, submits its "Examples of Leak Emissions and Repair Cost Effectiveness" document in response to the "Oil and Gas Sector: Emission Standards for New and Modified Sources" Proposed Rule, Docket No. EPA-HQ-OAR-2010-0505. This document supplements INGAA's prior comments filed on December 4, 2015 (see EPA-HQ-OAR-2010-0505-6872). This document was discussed during the OMB meeting on April 26, 2016.

Sincerely,

Terry Boss

Terry Boss
Senior Vice President for Environment, Operations, and Safety
20 F Street, N.W., Suite 450
Washington, DC 20001
(202) 216-5900

Interstate Natural Gas Association of America

Examples of Leak Emissions and Repair Cost Effectiveness

Scenario 1: Small Diameter, Low Pressure Valve Stem Packing (.5 scf/m) Leak.

Leak in aboveground 3 inch diameter valve; all bolts have been tightened, but leak persists. Valve stem packing pair is required. Repair is completed while valve and piping are in service. Therefore, no pipe section blow down is required to conduct repair.

Scenario 2: Small Diameter, Low Pressure Valve (.5 scf/m) Leak

Leak in aboveground 3 inch diameter valve; all bolts have been tightened, but leak persists. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, disassembling flanges and replacing leaking valve. Pipe section must be blown down to conduct repair.

Scenario 3: Medium Diameter, Medium Pressure Valve (.5 scf/m) Leak

Leak in aboveground 12 inch diameter valve; welded piping. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, cutting out welds, replacing leaking valve and rewilding piping. Pipe section must be blown down to conduct repair.

Scenario 4: Large Diameter, High Pressure Valve (.5 scf/m) Leak

Leak in below ground 24 inch diameter valve; welded piping. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, cutting out welds, replacing leaking valve and re-welding piping. Pipe section must be blown down to conduct repair.

Scenario 5: Large Diameter, High Pressure Valve (.5 scf/m) Leak

Leak in below ground 24 inch diameter valve; welded piping. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, cutting out welds, replacing leaking valve and re-welding piping. Pipe section must be blown down to conduct repair.

Summary Table of Costs and Methane Savings

Valve Scenario	#1 3" Valve, Small Packing Leak	#2 3" Valve, Small Leak	#3 12" Valve, Small Leak	#4 24" Valve, Small Leak	#5 24" Valve, Small Leak; PL Segment Blowdown Required
Leak Emissions:					
Operating Pressure, psig	100	100	500	750	750
Leak Rate, scf/min	0.5	0.5	0.5	0.5	0.5
Leak Rate per Day, scf/day	720	720	720	720	720
Methane Emissions per Day, metric tons (MT CH4/d)	0.013	0.013	0.013	0.013	0.013
CH4 Emissions – 6 months (MT CH4)	1.18	1.18	1.18	1.18	1.18
CH4 Emissions – 6 months (MT CH4)	2.40	2.40	2.40	2.40	2.40
Annual CH4 Emissions, (MT CH4/yr)	4.79	4.79	4.79	4.79	4.79
Repair Requirements:					
Upstream/Downstream Station Piping that Must be Blown down to Conduct Repair, feet	0	100	100	100	100
Mainline Pipe that Must be Blown down to Conduct Repair, miles	NA	NA	NA	NA	10
Station Piping Blowdown Volume required to Complete Repair, scf	0	38	2,745	16,310	16,310
Pipeline Segment Blowdown Required to Conduct Repair, scf	NA	NA	NA	NA	8,611,705
Total Volume Released to Conduct Repair, scf					8,628,015
Repair Costs:					
Labor	$180	$180	$13,500	$22,000	$22,000
Materials	$0	$4,000	$21,000	$60,000	$79,000
Gas Lost Cost (Volume x $0.003/scf)	$0	$0.11	$8.23	$48.93	$25,884
Total Repair Cost, including gas lost	$180	$4,180	$34,508	$82,049	$126,884
Cost/Ton CH4 Reduction					
• Annual Basis	$180	$870	$7,200	$17,100	$26,500

Key Points:

- The same size leak detected by the proposed LDAR survey can result in very wide variances in the amount of methane released and the costs incurred due to the needed repair processes. Careful planning and coordination of repairs will reduce overall methane releases and minimize the cost of the reduction strategy ($/MT CH4) as compared to arbitrary repair schedules. These are the tenets behind alternative LDAR recommendations, including the INGAA DI&M program.
- Many repairs conducted promptly under the proposed LDAR program would result in more methane being released during the repair processes than the initial leak due to unscheduled blowdowns required to isolate the component for repair. Coordination with other maintenance practices and processes that include scheduled blowdowns will result in reduced overall methane emissions. These are basic differences between the proposed EPA rule and INGAA proposed alternatives.
- The cost effectiveness (cost per ton reduction) can vary widely under the proposed LDAR program. Leaks repaired from tightening connections / bolts and minor valve packing repairs are generally cost effective when an appropriate survey frequency is used. The replacement of major components (e.g., large valves) greatly increases the methane emission reduction costs and the necessity of depressurizing the facility to conduct that repair (blowdown) offsets the perceived methane reduction benefits.

Scenario Descriptions and Assumptions

Scenario Descriptions:

Scenario 1: Small Diameter, Low Pressure Valve Stem Packing Leak

Leak in aboveground 3 inch diameter valve; all bolts have been tightened, but leak persists. Valve stem packing pair is required. Repair is completed while valve and piping are in service. Therefore, no pipe section blow down is required to conduct repair.

- Flange leak rate: Small leak @ 0.5 scf/min
- Compressor Station piping between upstream to downstream isolation valves: 0 feet
- Operating Pressure: 100 psig

Labor
- One person, 4 hours minimum
- Labor Rate ($ 30/hour plus 50% for benefits) $45.00/hr

Materials:
- Minimal cost for valve stem packing materials $0

Emissions: Assumed 1 Metric Ton for calculation purposes.

Scenario 2: Small Diameter, Low Pressure Valve Leak

Leak in aboveground 3 inch diameter valve; all bolts have been tightened, but leak persists. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, disassembling flanges and replacing leaking valve. Pipe section must be blown down to conduct repair.

- Flange leak rate: Small leak @ 0.5 scf/min
- Compressor Station piping between upstream to downstream isolation valves: 100 feet
- Operating Pressure: 100 psig

Labor
- One person, 4 hours minimum
- Labor Rate ($ 30/hour plus 50% for benefits) $45.00/hr

Materials:
- New 3 in Ball Valve (ANSI 600-900 valves range from $2000-7000) $4,000

Scenario 3: Medium Diameter, Medium Pressure Valve Leak

Leak in aboveground 12 inch diameter valve; welded piping. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, cutting out welds, replacing leaking valve and rewilding piping. Pipe section must be blown down to conduct repair.

- Flange leak rate: Small leak @ 0.5 scf/min
- Compressor Station piping between upstream to downstream isolation valves: 100 feet
- Operating Pressure: 500 psig

Repair Requirements:

Labor, including contractors

• Company Labor, including inspection and supervision	$2,500
• Certified welding contractor	$4,000
• Non-destructive testing (x-ray contractor)	$2,500
• Track hoe and qualified operator (required to hold valve and piping)	$1,500
• Coating removal /recoating and painting (contractor)	$3,000
Total Labor, including contractors	$13,500

Materials:

• New 12 in Ball Valve (ANSI 600-900 valve with gear operator)	$20,000
• Miscellaneous materials (coatings & paint)	$1,000
Total Materials	$21,000

Scenario 4: Large Diameter, High Pressure Valve Leak

Leak in below ground 24 inch diameter valve; welded piping. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, cutting out welds, replacing leaking valve and re-welding piping. Pipe section must be blown down to conduct repair.

- Flange leak rate: Small leak @ 0.5 scf/min
- Compressor Station piping between upstream to downstream isolation valves: 100 feet
- Operating Pressure: 750 psig

Repair Requirements:
Labor, including contractors

• Company Labor, including inspection and supervision	$5,000
• Certified welding contractor	$4,000
• Non-destructive testing (x-ray contractor)	$2,500
• Track hoe and qualified operator (required to hold valve and piping)	$1,500
• Coating removal /recoating and painting (contractor)	$3,000
• Excavation (contractor)	$6,000
Total Labor, including contractors	$22,000

Materials:

• New 24" ball valve (ANSI 600-900 valves range from $50,000-100,000)	$60,000
• Valve actuator	$17,000
• Miscellaneous materials (fill material, coatings & paint)	$2,000
Total Materials	$79,000

Scenario 5: Large Diameter, High Pressure Valve Leak

Leak in below ground 24 inch diameter valve; welded piping. Valve replacement is required. Compressor station piping will be isolated by closing upstream and downstream valves, cutting out welds, replacing leaking valve and re-welding piping. Pipe section must be blown down to conduct repair.

- Flange leak rate: Small leak @ 0.5 scf/min

- Compressor station piping between upstream to downstream isolation valves: 100 feet
- Operating pressure: 750 psig
- 24" Pipeline segment blow down required to complete repair: 10 miles

Repair Requirements:
Labor, including contractors

• Company Labor, including inspection and supervision	$5,000
• Certified welding contractor	$4,000
• Non-destructive testing (x-ray contractor)	$2,500
• Track hoe and qualified operator (required to hold valve and piping)	$1,500
• Coating removal /recoating and painting (contractor)	$3,000
• Excavation (contractor)	$6,000
Total Labor, including contractors	$22,000

Materials:

• New 24" Ball Valve (ANSI 600-900 valves range from $50,000-100,000)	$60,000
• Valve actuator	$17,000
• Miscellaneous materials (fill material, coatings & paint)	$2,000
Total Materials	$79,000

SPILMAN THOMAS & BATTLE, PLLC
ATTORNEYS AT LAW

James D. Elliott
717.791.2012
jelliott@spilmanlaw.com

August 2, 2016

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

Re: Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

Dear Administrator McCarthy:

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

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

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

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

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

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

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

The Texas Independent Producers & Royalty Owners Association ("TIPRO") is a trade association representing the interests of 3,000 independent oil and natural gas producers and royalty owners throughout Texas. As one of the nation's largest statewide associations representing both independent producers and royalty owners, members include small family businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B. ADDITIONAL ISSUES IN NEED OF REVISION

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

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

2. Certain oil wells should be exempt from the LDAR requirements. Similarly, there should be a different definition of "low pressure well."

3. There should be an "off ramp" for the LDAR requirements when existing wells or new wells become "low production" or marginal wells.

4. Although Subpart OOOOa provides a state equivalency process for LDAR programs, the procedure set forth in the regulations (§60.5398a) is overly burdensome to the point that states are unlikely to avail themselves of the provisions.

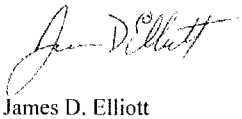
5. The digital/video LDAR related requirements (§60.5420a) are unnecessary and should be removed.

6. EPA should reinstate options to reduce the emission surveys to annual surveys. While certain operators might prefer the consistency of bi-annual surveys, many independent operators and small entities would still benefit from the ability to reduce survey frequency by demonstrating few/no leaks during consecutive surveys.

7. Extended implementation periods are necessary and warranted for small entities that lack the bargaining power and resources (and the in-house capabilities) to contract with consultants to undertake the surveys, testing and documentation required by Subpart OOOOa. .

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

Respectfully submitted,



James D. Elliott

Counsel to the Independent Associations

cc: Janet McCabe, EPA
Peter Tsirigotis, EPA
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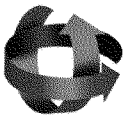

ENERGYINDEPTH®

Obama Admin. Inclusion of Marginal Wells In Methane Rule Based on "Unconventional" Data, Misrepresentation of the Facts

12:12pm EDT May 24, 2016

by Katie Brown, PhD
katie@energyindepth.org, Washington, D.C.

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One of the most head-scratching aspects of the Obama Administration's recently finalized methane rule is the fact that after Environmental Protection Agency's (EPA) draft regulations included an exemption for marginal wells – since small sources, obviously, are not releasing large amounts of methane – EPA's final rules actually eliminate that exemption, and with no reasonable explanation.

EPA's August 2015 draft regulations on methane included a set of control techniques guidelines (CTG) that

explicitly acknowledged that marginal operations would be exempt in EPA's methane rule – or its New Source Performance Standard (NSPS) – on the basis of economic hardship and because emissions at marginal sites are "inherently low." As EPA put it,

> *"For purposes of this guideline, the emissions and programs to control emissions discussed herein would* ***apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrel equivalents per well per day*** *(15 barrel equivalents), and the collection of fugitive emissions components at compressor stations in the production segment. It is* ***our understanding that fugitive emissions at a well site with low production wells are inherently low*** *and that many well sites are owned and operated by small businesses.* ***We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved.*** *For the purposes of this guideline, fugitive emissions recommendations would* ***not apply to well sites that only contain wellheads.*** *" (p. 9-1; emphasis added)*

In December 2015, the Independent Petroleum Association of America (IPAA) and the American Exploration & Production Council (AXPC) cited that exact passage in its official comments to the EPA. "This recognition is entirely appropriate and accurate," IPAA and AXPC wrote. The groups added that they "agree that a fugitive emissions program should not apply to facilities with only a single wellhead."

So how did the Administration, less than a year later, come to exactly the opposite conclusion? Thus far, EPA has claimed that "several commenters" had recommended not including low producing wells and, as the agency puts it,

> "Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site."

But as the CTG clearly shows, it was EPA – *not commenters* – who had initially suggested marginal wells should be treated differently, and potentially even exempted from the agency's methane rule. The EPA claimed the industry didn't adequately support its position, even though the industry was simply agreeing with what the EPA had already formulated!

"Unconventional" Data Underscores Decision

Meanwhile, a quick look at what some anti-fracking commenters had to say sheds a bit of light on what could be the motivation behind EPA's strange and contradictory move. The Clean Air Task Force (CATF) for instance, quoted a study spearheaded by the Environmental Defense Fund (EDF), *Zavala-Araiza et. al*, which CATF says shows that "lower producing wells can have significant emissions." CATF would have you believe, counterintuitively, that small sites can emit the same volume as larger sites.

But *Zavala-Araiza et. al* actually changes the definition of "super-emitter" in order to make this claim. The researchers of the study define "functional super-emitters" not as sites that emit a lot of methane but as sites where *a certain percentage* of that well's methane may be leaking. From the report:

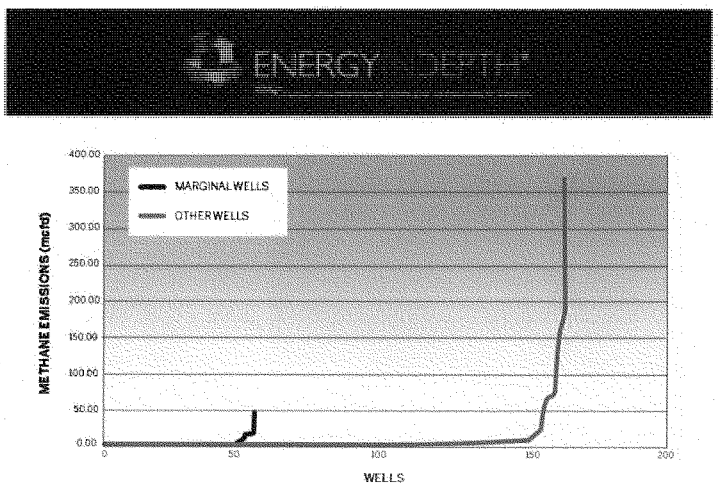
> "We designed a conceptual framework that *functionally* defines superemitting sites as those with the highest proportional loss rates (methane emitted relative to methane produced)."

It goes on to say,

> "[L]ower production sites (10–100 thousand standard cubic feet per day or Mcf/d) are almost twice as likely to be among the top 5% of emitters relative to sites with an order of magnitude higher rates of production (100–1000 Mcf/d) (Table 1). Not unexpectedly, however, the highest producing sites (>1000 Mcf/d) are 4–7 times more likely than other sites to be among the highest emitting 5% of sites. Consequently, the conventional definition of super-emitters would be biased toward the highest producing sites."

In other words, even the researchers themselves admit that what they are doing is not exactly conventional.

Also, a closer look at the data used in the EDF study demonstrates that marginal wells clearly represent a low component of the methane emissions universe.



The above graphic shows that although a similar *percentage* of total production *can* emit from marginal wells when compared to high-producing wells, *actual emissions* from marginal wells are negligible.

Having said that, however, even the above data on marginal wells from the study are highly questionable considering they indicate high emitting marginal wells leak **nearly half** of their extracted gas. This is unrealistic as no producer would continue operating a well that is losing half of its value.

If the Obama Administration's objective is come up with a justification for new federal regulations, presenting the data in this "unconventional" way would be one way to give it "cover." But if the Administration insists on using this flawed EDF data as the reason for rejecting its own original proposal to exempt marginal wells,

it should also bear the burden of explaining EDF's unrealistic conclusions.

Small Producers Hit the Hardest

The EPA is correct that small businesses are the predominant operators of marginal wells, because larger companies often sell wells to small businesses when they no longer want to operate them. But, the Administration's decision on this NSPS will certainly change that.

What's more is the Administration's decision doesn't meet fundamental test of defining the Best System of Emissions Reductions that must be used in setting a NSPS. The fugitive emissions requirements in the regulation are based on operations when a well is new, when its production is at its highest rate – 1,000, 2,000, 5,000 mcfd. But, when a well becomes marginal and its average production drops to 22 mcfd, it cannot bear the cost of a fugitive emissions program designed and justified for production rates 50 to 100 times its production rate. By embedding the fugitive emissions program on these wells for the life of their existence, the Administration is guaranteeing that they will end that life well before it otherwise would end, hurting small producers the most.

This may be a great decision for the "keep it in the ground" activists but it's a bad decision for American energy security and American energy consumers.

Data Integrity Concerns

The Administration's decision on marginal wells adds to growing concerns about its methane rules.

A report last year by NERA Economic Consulting – which has performed analyses for the U.S. Department of Energy, among others – found that the methane rule was based on a single, flawed economic study of the "social cost of methane." The study was also authored by individuals within the EPA.

Additionally, calculations by Energy In Depth showed that President Obama's broader methane mitigation strategy – which includes the EPA's methane rule – would yield only 0.0047 degrees Celsius of avoided warming the end of the century. The EPA also projected hundreds of millions of dollars in benefits based on the value of natural gas that would be captured and sold as a result of the rule, but the value was based on natural gas prices being $4 per thousand cubic feet (mcf). The current average natural gas price is nearly half that, or $2.16/mcf.

Just weeks before rolling out the final methane rule, the EPA significantly increased its estimates of methane emissions from petroleum and natural gas systems. The EPA did not identify additional emissions, but simply began assuming that marginal wells had emissions profiles similar to those of higher producing wells.

The EPA admitted that its emissions estimates "greatly increase" as a result of its new methodology, "due to the activity data revision alone."

But as the EPA itself acknowledged last summer, marginal wells have "inherently low" emissions – even though the Administration now says otherwise.

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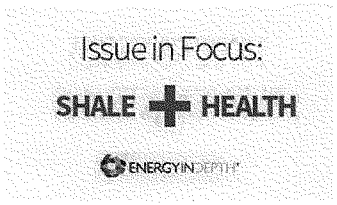

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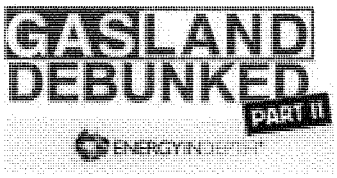

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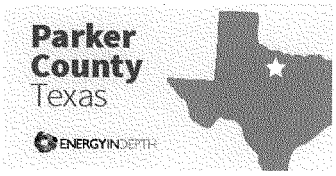

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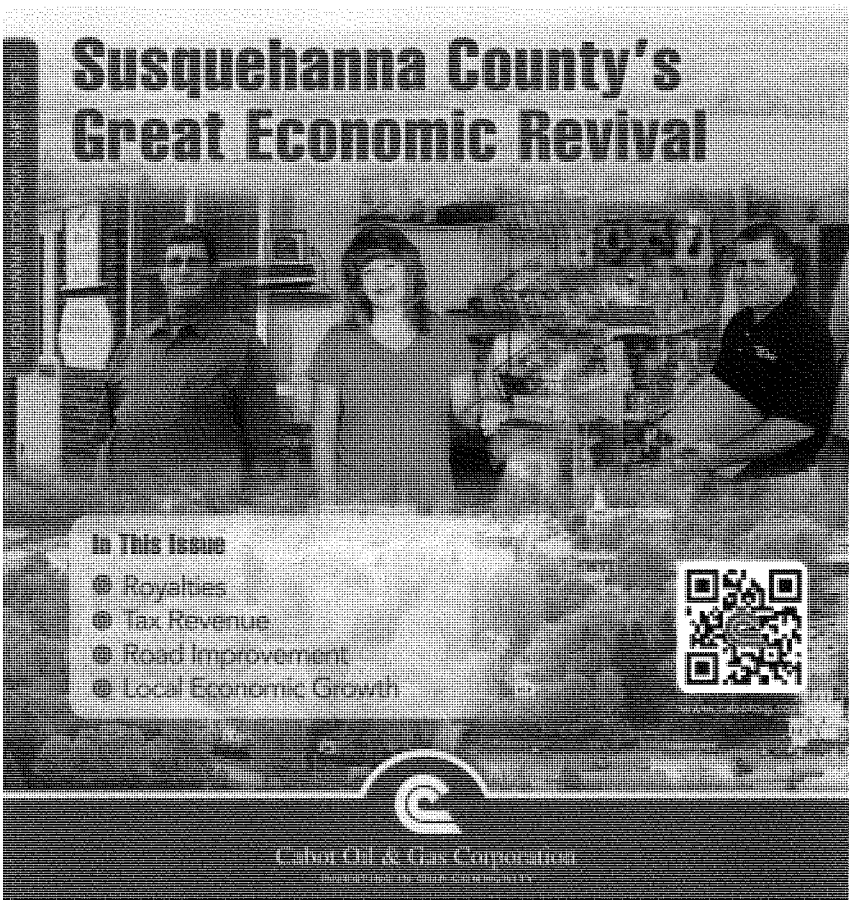
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2

"OUR EMPLOYEES LIVE HERE. WE LIVE HERE. AND WE WANT TO HAVE THE COMMUNITY WE CALL HOME BE PROSPEROUS."

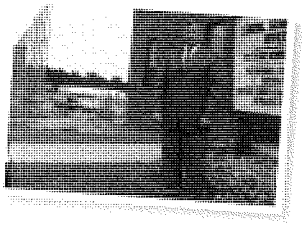
George Stark
Director
External Affairs
Cabot Oil & Gas Corporation

www.cabotog.com

INVESTING $1.5 BILLION SO FAR

Cabot Oil & Gas Corporation is proud to be playing a vital role in the incredible economic turnaround that's having a positive impact on both the residents and businesses of Susquehanna County and beyond. In fact, since starting operations in this region, we've invested over $1.5 billion in our community.

And the great news is...this is just the beginning!



Millions Paid in Royalties

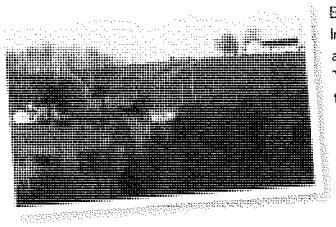
Cabot has already paid millions of dollars to Susquehanna County landowners in the form of natural gas royalty and lease payments. This money creates a prosperous domino effect as landowners spend their new income on goods and services within the community.

Funding Local Education

Gas lease and royalties also bring economic benefits to those in the community who don't receive payments directly – like the residents of the Elk Lake School District. The district receives gas royalties from leased land. This extra income is helping keep taxes lower and allowing the school to plan for future expansions and upgrades at a time when state education budgets are being drastically reduced.

Creating Greater Tax Revenue

Cabot's activities in the Marcellus Shale also have financial benefits in the form of increased tax revenue. Not only do we contribute a significant amount of money each year in the form of Pennsylvania corporate taxes, but portions of landowners' royalty payments help the public good by increasing the tax base of both Susquehanna County and Pennsylvania as a whole.



Better Roads for Everyone

In order for the local economy to thrive, a dependable infrastructure is essential. That's why Cabot has invested over $18 million to date on improving and maintaining Susquehanna County roads for the safe and efficient transportation of goods and services.

New Prosperity for All Kinds of Businesses

At Cabot, we've hired hundreds of local employees and partnered with many Susquehanna County companies that help us develop the natural gas resources of the Marcellus Shale. But our activities are also creating a hub of economic growth that's bringing prosperity to a range of other local businesses that serve a variety of markets – from stores and restaurants to hotels, car dealerships, housing developers, insurance companies and more.

But don't take our word for it. Take theirs!

Andre & Son, Inc. – Joe Andre, Owner
"We're a farm-oriented business and we've been supplying seed mixtures used in Cabot's land restoration efforts and providing advice. We have a very good business relationship with Cabot."

Elk Lake Filling Station – Bill and Lori Davis, Owners
"Since purchasing our station four years ago, business has been booming. We've almost doubled our staff and provided additional seating to better serve our customers."

Hawk Insurance Agency – Jeffery B. Tyler, Partner & Agent
"Thanks to Cabot, our business is growing in unexpected ways. The natural gas industry has brought new life to the area."

The Inn at Montrose – Gretchen Backer, Owner
"The natural gas industry is helping us on a daily basis. Our hotel is full and our waitresses and cooks are busy. We've tripled our amount of employees and demand is still rising."

Lockhart's Convenient Store – Dan Lockhart, Owner
"We wouldn't be here if it weren't for the natural gas industry. It saved us from going out of business and has done so much good for the local economy."

A Brighter Future...For All of Us

At Cabot, we're proud to play a part in helping America develop its vast domestic energy resources. And we're equally pleased to have such a positive economic impact on the residents and locally owned businesses of the Susquehanna County region.

@CabotOG cabotsusquehanna

In 2011, PA's natural gas industry generated over $12.8 billion in economic activity.

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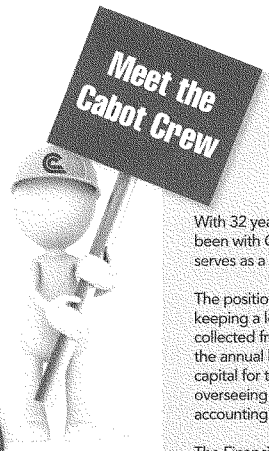

JOHN EDMONDS

Financial Analyst – North Region

With 32 years of industry experience, John has been with Cabot for over 11 years and currently serves as a financial analyst.

The position means wearing a lot of hats and keeping a lot of plates spinning as information is collected from all departments to help prepare the annual budget and forecasts for revenue, expenses and capital for the North Region of Cabot's operations. Responsibilities extend to overseeing a range of accounting and financial matters, always making sure proper accounting practices and regulations are followed.

The Financial Analyst also serves as the project manager for office space build outs, working with architects, general contractors, electricians and more to ensure the efficient construction and furnishing of new office structures.

John likes the fast pace and the constant challenge of providing support for so many departments and says he enjoys working in a region "with so much beautiful country and such a great community."

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Washington, DC 20515

July 27, 2016

The Honorable Sally Jewell
Secretary
U.S. Department of the Interior
1849 C Street, NW
Washington, D.C. 20240

Dear Secretary Jewell:

Earlier this year, Speaker Paul Ryan assembled several committee Chairmen in the U.S. House of Representatives to establish a Task Force aimed at reducing regulatory burdens to grow our economy. Of the principles outlined, we found that it is absolutely critical for the federal government to regulate smarter while also delivering affordable and reliable energy to American families and businesses. The findings of the Task Force's recently released white paper took months to assemble, and incorporated ideas from many Members of Congress, individuals, small business owners, and recognized regulatory experts.

We call your attention to the important findings of this white paper because the Department of the Interior has been a major offender of these principles – promulgating thousands of duplicative and burdensome rulemakings that do little to offer measurable impacts on the safety, security or economic well-being of our nation's citizens. Rather, many of the Department's regulations penalize and discourage entrepreneurship, overstep state jurisdiction, and drive up costs for developing energy resources on federal lands. The net effect of these burdensome rules is to make energy development on federal lands cost prohibitive and ultimately to penalize the citizens and economies of many states whose lands remain largely in federal control. A recent example of this is the Bureau of Land Management's (BLM) proposed Waste Prevention, Production Subject to Royalties, and Resources Conservation Rule (81 Fed. Reg. 6616) to further regulate methane emissions.

The BLM lacks Clean Air Act jurisdiction – a law that clearly charges the Environmental Protection Agency (EPA), in partnership with states, to regulate emissions. Moreover, according to the EPA's own data, U.S. emissions from natural gas systems are lower than they were in 2005 – despite our nation's vast increase in natural gas development over the same period. Similarly, a recent study conducted in part with scientists from the National Oceanographic and Atmospheric Administration (NOAA) found that global methane increases since 2006 are likely from biogenic sources, rather than thermogenic emissions such as those associated with natural resource production - contradicting emissions inventories.[1]

We are concerned that the BLM has rushed forward to finalize new methane emissions measures as a solution in search of a problem. Unfortunately, these regulations fail to address BLM's ongoing permitting delays for natural gas gathering line rights-of-way. The best method to capture methane emissions from a well site is through the construction of natural gas gathering lines and pipelines. According to the BLM manual, BLM aims for a 60-day review of pending right-of-way permits so companies can construct pipelines. Yet, in data submitted by the BLM itself to the House Natural Resources Committee, not a single field office has been able to meet this target. In many cases, BLM is taking over six months to process a permit. This is unacceptable.

This rule adds another layer of duplicative federal regulation on top of already existing federal and state regulations. The rule oversteps BLM's regulatory jurisdiction, and completely fails to address crucial failures by the BLM to capture methane emissions through common sense methods such as timely right-of-way permitting. For these reasons, we urge the agency to withdraw this misguided effort.

The development of oil and natural gas on federal lands remains a critical component of our nation's renewed status as a global energy leader. Energy development is a generator of jobs and revenue that impact federal, state and local budgets. Most importantly, domestic energy production has helped to lower energy prices for American families, manufacturers, and businesses, which in turn have helped to further stabilize our economy. Rather than put all of these benefits in jeopardy, the BLM should continue to work collaboratively to drive more innovative technologies that build upon existing methane emissions decreases, while also promulgating common sense reforms to address the ongoing delays that plague the current right-of-way permitting process.

[1] H. Schaefer et al., Science 10.1126/science.aad2705 (2016).

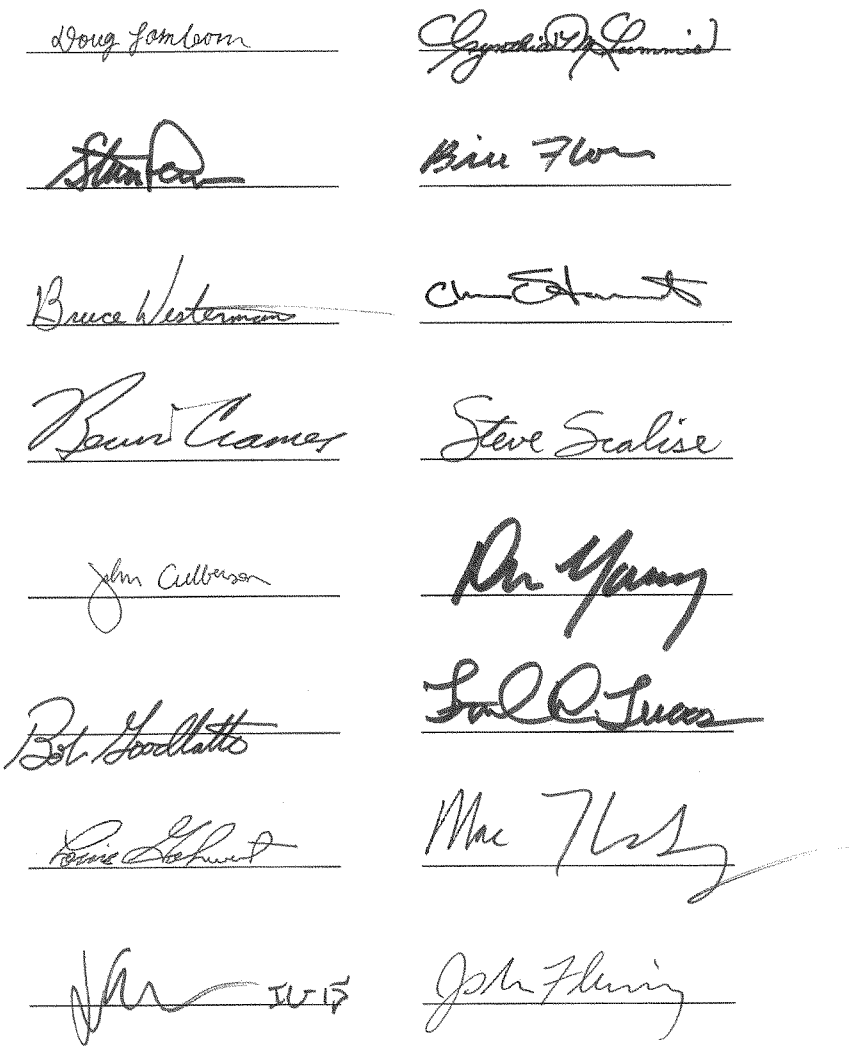
We appreciate your consideration of a better way to regulate responsible oil and natural gas exploration and production on federal lands and greatly look forward to your prompt reply to this letter that includes in detail what measures the Department is taking to address these right-of-way permitting backlogs.

Sincerely,

Rob Bishop
Chairman
House Natural Resources Committee

Kevin McCarthy
Majority Leader

Cc: The Hon. Raul Grijalva, Ranking Member, Committee on Natural Resources



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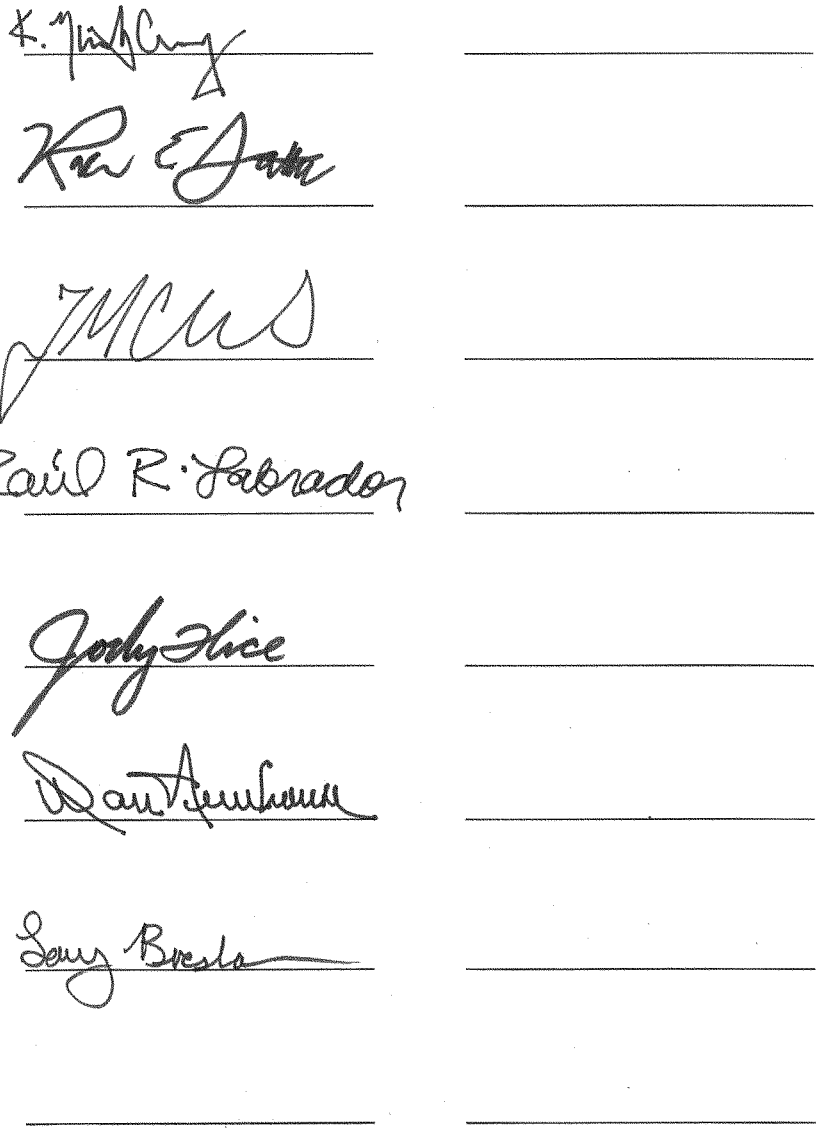

The Case for Shale

Eric R. Claeys

THE POLITICAL ECONOMY of the United States is often described as a free-enterprise system—"free," because the American political system protects individual rights of life, liberty, and property; "enterprise," because those rights encourage Americans to become entrepreneurs. The most innovative Americans create new fields of industry and endeavor, and they use their freedom to circulate the benefits of their innovation to everyone else in this country and beyond. Americans have seen this creative cycle play out time and again—in the automobile industry in the first half of the 20th century, the pharmaceutical field in the 1980s, or the "dot-com" boom in the 1990s.

The most recent free-enterprise success story comes from the energy sector—the "shale revolution." In the late 1990s and early 2000s, small American energy companies perfected technologies to extract oil and natural gas from rock formations previously thought to be impermeable. The technologies are called "unconventional" drilling techniques; the impermeable rock is called "tight" rock; and the most commonly drilled rock formations are called "shales." The shale revolution refers to the surge in U.S. energy production, when domestic energy companies started applying unconventional technologies to extract oil and gas from shales and other tight rock. The shale revolution has reduced America's dependence on foreign oil and gas, created valuable jobs for many Americans, and expanded American consumers' purchasing power and freedom of action in countless ways.

Yet the shale revolution faces a serious political threat. In the culture and in politics, environmentalists criticize unconventional production as exploitative and polluting. Grassroots environmentalists and concerned residents are lobbying states and local governments to ban shale production.

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And so far, critics of shale production seem to be gaining the moral high ground. They indict shale production in moral terms. Unconventional energy producers are accused of "polluting" sources of fresh water and the air, and of "exploiting" the landowners from whom they lease. By contrast, defenses of shale production are fairly apolitical, often resting on economic statistics about wealth and jobs. To date, however, the shale revolution's supporters haven't developed or effectively publicized an account of why the shale revolution is also just, a success story on a moral level as well as an economic one.

In other words, the debate about the shale revolution is becoming lopsided in the same way as many other debates about business regulation. In arguments about "cultural" or "social" issues—immigration, gun control, or abortion, for instance—both sides have well-developed accounts of what a just political community looks like, what individual rights such a community cherishes, and whose rights are threatened by the other side's proposals. All too often, however, in debates about business regulation, interventionist journalists and grassroots activists indict a field of business for being dirty, hypercompetitive, or predatory. When legislators then propose to restrict the field of business, supporters argue from a defensive position. Instead of linking the business in question to a moral good, they defend it with uninspiring apolitical arguments.

In ongoing debates about shale production, supporters shouldn't shy away from making a moral defense of the shale revolution. And such a defense in the energy arena may also offer us a better sense of how champions should be defending our system of free enterprise more generally.

THE SHALE REVOLUTION

The shale revolution is the product of a technological breakthrough. Until recently, most oil and gas was produced from large subterranean reservoirs. It is cheaper and easier to tap these large reservoirs than it is to explore for small pockets of oil or gas trapped in shales or other impermeable rock formations. Even so, according to 2013 estimates by the International Energy Agency, around the world, there is more oil recoverable from unconventional resources than from conventional resources (3.2 trillion barrels versus 2.7 trillion barrels), and about three quarters as much natural gas recoverable from unconventional resources as from conventional ones (330 trillion cubic meters versus 460 trillion). Worldwide petroleum prices increased steadily over the last 30 years, and at some point they were bound

to increase past the break-even point for shale exploration—*if* prospectors could develop technology making it feasible to explore.

Throughout the 1980s and 1990s, American energy producers tried to develop such technologies. In the late 1990s, a few producers discovered a successful formula combining three elements. One is hydraulic injection—which opens up shale rocks with water pressure, so that oil or gas can escape. (This pressurized fracturing gives shale exploration the names "hydraulic fracturing" and "fracking.") But fractures can close quickly, before oil or gas escapes, once the stream of water is shut off. To avoid this possibility, fractures are kept open with the second element: "proppants," consisting of sand or artificial ceramic beads.

The last element is horizontal drilling. When energy producers construct wells, they drill and install a vertical pipestem, usually one and a half or two miles deep. They then "arc" horizontal pipes at right angles away from the vertical pipestem, in the middle of the layer of shale being fractured. By snaking multiple horizontal pipes (usually six to eight) away from the pipestem, producers minimize the damage and inconvenience they inflict on the surface. And because these horizontal pipes often run two miles from their vertical pipestems, they help a company extract all the oil or gas from shale rocks in a five- or six-mile-diameter cylinder.

Since energy companies started using these three techniques together, American energy production has surged. From 2000 to 2015, American natural-gas production increased by about 42%, and American crude-oil production increased by 62%. In 2000, shale gas and tight oil contributed almost nothing to American production; as of 2015, each constituted about half of U.S. production of natural gas and crude oil. Thanks to hydraulic fracturing, the United States stopped being a net oil importer in 2011.

The shale revolution benefits Americans in many ways. The surge in domestic oil and gas production deserves much of the credit for offsetting the effects of the 2008 recession and for stoking much of the recovery (such as it is) that the country has experienced since then. Shale exploration has created hundreds of thousands of jobs in the energy industry, and many more in transportation and other fields that benefit indirectly from cheaper and more plentiful oil and gas. Many of these jobs are risky, not only because shale production is a boom-or-bust industry but also because oil drilling presents health and safety dangers. But the jobs are also lucrative; an industry website estimated that, when fracturing took

off in North Dakota, entry-level workers were earning $66,000 annually, and the average annual salary in the industry was over $112,000.

The shale revolution has also helped consumers. In 2013, crude oil sold on world markets at more than $110 per barrel; as of early 2016, thanks in large part to increased American production of shale oil and gas, crude is selling just above $30 per barrel. By one rough estimate, the increase in the supply of natural gas gives Americans on average $150 more in purchasing power per capita per year.

To be sure, drops in oil and gas prices will discourage new shale production in the near future. But the companies that have led the shale revolution are researching how to lower their break-even points. And prices for oil and gas will eventually go back up, as cheaper prices stimulate higher energy consumption and that consumption increases in developing countries around the world. In short, the shale revolution has already helped Americans prosper and will continue to do so—unless cultural and political developments pressure energy producers to give up on shale exploration.

THE ENVIRONMENTALIST CRITIQUE

As the shale revolution took off, some environmentalists were quietly supportive. They believed that natural-gas use is desirable in the short and medium terms, because gas is a cleaner-burning substitute for coal. Yet other environmentalists believe that fracturing is risky and disruptive to the neighborhoods where drilling takes place. Others worry that the oil and gas produced by fracturing exacerbate climate change, and still others fret that shale production perpetuates the mindset that we can all rely on fossil fuels forever. And in the last five years, these and other similar views have turned environmentalist donors and leaders decisively against fracturing.

In fall 2015, in the middle of an NFL Monday Night Football game in Charlotte, two environmental activists rappelled off of a stadium balcony to display a banner protesting a Charlotte-based bank's loan to an energy company for a fracking project. Several anti-fracking movies have been released, the leading one being the 2010 HBO documentary *Gasland*. The film suggests that energy companies trick the landowners they bargain with and leave their neighborhoods polluted and impossible to clean up. It also suggests that hydraulic fracturing causes nearby residents to suffer chronic illnesses, pollutes fresh-water sources, and in one case made tap water flammable. And *Gasland* also suggests that

energy producers have undue influence in politics. At the behest of energy producers, the movie warns, Congress included in a 2005 federal energy law an amendment exempting hydraulic fracturing from the federal Safe Drinking Water Act.

Cultural criticisms like these have stoked political and legislative efforts to reform fracking. The federal Environmental Protection Agency is reviewing scholarship and case reports on whether hydraulic fracturing contaminates underground fresh-water supplies. In their campaigns for the Democratic nomination for the presidency, Hillary Clinton and Bernie Sanders both promised to use federal regulatory powers to stop fracking.

Today, however, most of the political controversy occurs at the state and local levels. Localities can try to use their powers to regulate zoning and land use to restrict fracking, and state environmental and energy agencies have jurisdiction over energy production as well. The Vermont legislature banned fracking in 2012, though that ban was purely symbolic because there aren't shale plays in Vermont. Governor Andrew Cuomo used his executive powers to impose an indefinite moratorium on hydraulic fracturing in New York, and the Maryland legislature enacted a moratorium on fracking for at least two years—far more consequential maneuvers, since New York and Maryland both sit over the Marcellus Shale Play. City councils and voter initiatives have banned or delayed fracking in some towns—most notably in Denton, Texas, but also in municipalities in Pennsylvania, Ohio, and Colorado. Some of these restrictions (like Denton's) have been voided by state laws stripping localities of power to interfere with energy production; others (like those in two Colorado towns) have been declared invalid by state courts because they conflict with state-level energy laws and regulations. But even if most of these early efforts have been stopped, they have inspired similar efforts in other states—North Carolina, Georgia, Florida, Ohio, and Michigan, among others.

In these debates, environmentalists claim to be on the side of right. *Gasland* portrays fracturing as a morality play with villains (energy producers) and victims (landowners). Real-life local political debates are likewise cast with evildoers and righteous victims. An anti-fracking group, *Frack Free Colorado*, identifies the moral stakes for its advocacy: "[t]o protect Coloradans' basic rights to clean water, clean air, a safe home, and a sustainable future." Another Colorado critic accuses energy companies not only of polluting "our water, air, homes, and natural landscapes" but also of "pollut[ing] our democracy."

More ominously, supporters of the shale revolution are tacitly ceding the high ground. Of course, supporters do attempt to refute the unfounded accusations of critics. For example, Colorado's oil and gas commission found that *Gasland*'s "flaming faucet" occurred because of biogenic methane seeping into water sources naturally, not thermogenic methane pushed into water by drilling or hydraulic injection. Supporters also make practical arguments. For example, in voter referenda on fracking, supporters often warn local voters that they put themselves on the hook for big litigation bills when restrictions on fracking are challenged and thrown out of court. But most often, supporters cite the economic benefits of shale exploration and gas production: new wealth, new jobs, economic growth, and increased tax revenues for schools and other public services.

In politics, however, it's not enough to refute every inaccurate accusation or make arguments based exclusively on economic statistics. Exposés on fracturing and grassroots political campaigns both aim to shape public attitudes against fracturing over the long term. Even if supporters refute most of the criticisms and beat back most of the legislative proposals, they'll lose the contest over public opinion.

By ceding the moral high ground, energy producers neglect two important dimensions of politics. First, shale supporters neglect the role that public arguments play in a mass democracy. Many observers mistakenly assume that policy gets made primarily by two processes—direct decision-making in voting booths, and special-interest lobbying in legislatures and regulatory agencies. This portrait leaves out the role played by a certain kind of advocate. As Joseph Schumpeter explained, in a democracy, "the mass of people never develops definite opinions on its own initiative." Opinions are shaped through arguments and campaigns conducted by public intellectuals, who make it their "interest ...to work up and organize resentment, to nurse it, to voice it and to lead it."

While state and local grassroots environmental leaders and anti-shale journalists stoke public opposition to shale exploration, a few influential thinkers have attempted to bend public opinion in the other direction. For example, Phelim McAleer, an independent filmmaker, used crowdfunding to finance *FrackNation* as a response to *Gasland*. But there aren't nearly enough influential leaders doing such work.

Second, shale supporters neglect the role that justice plays in cultural and electoral debates about politics. Although a political debate on any

issue will have many different facets, the most effective way to gain control of such a debate is to articulate how one side violates people's rights or threatens a community's just way of life.

This is why many arguments for fracturing thus far have seemed uninspiring or defensive. There is not a lot of rhetorical force in warning residents of a city that it will be expensive to defend a municipal ban on fracturing. Cities are often asked to support proposals, at considerable public expense, for new sports stadiums or ambitious redevelopment projects. The politics of these proposals turn on whether voters are convinced that these projects are "giveaways" to sports teams or local developers, or instead are "investments" in projects that will be "anchors" or "catalysts" for prosperous community life. Similarly, a local ban on hydraulic fracturing may seem worth the cost and headaches of litigation—unless supporters can teach local citizens why the ban interferes with a legitimate activity and, more important, the community's well-being.

Nor is it persuasive or inspiring to cite the wealth and jobs that shale exploration creates. Supporters of legalized gambling often argue that new casinos will create new jobs and wealth. Sometimes these arguments succeed. But sometimes they don't—not when opponents paint commercial gaming as an industry that preys on risk addiction and contributes to family break-up and other social pathologies. Although the energy sector differs in basic ways from the casino business, it's telling that critics have likened energy production to "speculation," "profiteering," and reckless gambling ever since the first oil rushes. Unconventional energy producers need to make the case that their activity is not predatory but legitimate free enterprise.

In energy scholarship and policymaking, many specialists think it's enough to defend an activity like shale exploration using value-neutral methods, like cost-benefit analysis. Cost-benefit analysis is helpful in many settings, especially administrative settings, because it forces administrators to clarify and compare the consequences of different proposals. But cost-benefit analysis isn't as effective in the political arena—precisely *because* it talks about political tradeoffs in an apolitical way. In legal and economic scholarship, it's often taken for granted that personal-injury judgments incentivize companies to take precautions against accidents only when the precautions are cost-effective. In practice, however, one of the most devastating pieces of evidence a plaintiff's lawyer can use against a company defendant is a memo balancing the

costs and benefits of such precautions in dollars and cents. Companies are taking risks with consumers' safety, jurors intuit, and unjustly presuming to assign dollar values to risk choices that belong to consumers.

Similar intuitions drive the politics of shale exploration. For ardent environmentalists, cost-benefit analysis implies that dollars count for more than goods that are hard to quantify but ennobling—beauty, cleanliness, and fairness. Supporters need to justify shale exploration in similar terms.

MORALITY AND PROPERTY

Here, supporters of shale exploration should take a lesson from their critics. Environmentalists often cite fundamental rights to support their indictments of hydraulic fracturing. When the town of Longmont banned fracturing, it cited a passage from the Colorado constitution, which "confers on all individuals in the state, including the citizens of Longmont, certain inalienable rights, including 'the right of enjoying and defending their lives and liberties; of acquiring, possessing and protecting property; and of seeking and obtaining their safety and happiness.'" These constitutional passages follow the cadences of the Declaration of Independence. They resonate with ordinary voters because they appeal to moral rights. But the moral principles that justify those rights can also supply the moral dimension currently missing from defenses of unconventional energy production.

The Colorado constitution and the Declaration of Independence set two ultimate goals for political life—protecting the "safety" of the citizenry, and creating conditions in which citizens can pursue their own forms of "happiness." A moral defense of free enterprise follows from the basic rights and liberties implicit in these goals: the liberty to compete, the liberty to work, and property rights. Free competition empowers all citizens to develop and market skills or trades and decide how much their labor is worth. The right to work empowers every person to make a living by specialization, with a skill set that others deem valuable enough to hire.

Property rights are more complicated. Citizens' basic rights to safety and the pursuit of happiness entitle them all to equal opportunities to acquire resources and to use those resources for their well-being. Sometimes (as with waterways or roads), the best way for all citizens to enjoy a resource is for the government to own it and manage it as a public resource open to all. More often, however, government enlarges people's opportunities to acquire and use resources by protecting private

property. Private property encourages owners to discover unknown resources, and to invest in, improve, and produce useful goods and services from known ones. When owners then sell the products they make, they give other citizens new opportunities to acquire and use new resources in pursuit of their own goals.

This basic account adds much of the moral dimension missing from debates about shale exploration today. When energy companies discover new oil and gas reserves, they expand American consumers' freedom of action, by expanding the supplies of fuel, food, plastics, and other products available to everyone. If and when expanded supplies drive prices down, energy production increases consumers' liberty a second time, by letting them reroute savings from basic needs (especially fuel and energy bills) to other, more satisfying parts of their lives. And new energy discoveries also empower the citizens who take the new jobs they produce. So statistics about wealth creation and new jobs do matter—but are more effective in arguments about giving consumers and workers greater freedom of action to pursue their own happiness.

To maximize the advantages of this empowering system of free enterprise, however, well-designed property law is key. Only four countries in the world currently produce commercially useful quantities of tight oil or shale gas—the United States, Argentina, China, and Canada. American production exceeds the combined production of the other three by a factor of 10. And it is reasonable to suspect that the United States' system of private-property rights is the greatest factor facilitating the shale revolution. In virtually all other countries, minerals are considered public resources. By contrast, the United States and Canada treat the subsurface as private property, except where government holds the land in question as public land, or where (as has happened quite often in Canada) the government reserves the mineral estate when it conveys the land to private owners. In the rest of the world, when a prospector wants to search for minerals, he must get the government's permission; in most of the United States (and to a lesser extent Canada), prospectors ordinarily only need to convince private owners.

American law's treatment of the subsurface as private property is consistent with the principles of natural law and rights that have been hardwired in the common law since before the United States was founded. The principles are based on British jurisprudence. Until Parliament nationalized the United Kingdom's subsurface in the first

half of the 20th century, judges had treated the subsurface as private property for centuries, by linking ownership of the subsurface to ownership of the land over that subsurface.

The fullest defense of this rule was published in 1628, in the first part of a treatise on the laws of England by the jurist Lord Edward Coke. According to Coke, the earth deserves to be private property because it "doth furnish man with many other necessaries for his use, as it is replenished with hidden treasures... and also with great varietie of precious stones, and many other things for profit, ornament and pleasure." In other words, the subsurface should be considered private property because it contains resources that can contribute to people's flourishing. Some of those resources (Coke cited clay and iron) supply "necessaries" helpful for survival, while others (useful metals and treasure metals) contribute to "profit; ornament[,] pleasure" and happiness. But no matter what use these resources serve, someone needs to find them, capture them, improve them, and start using them. Private property gives proprietors the protection and encouragement they need to start that process of discovery and circulation.

The Western natural-law tradition also identifies several reasons why private property is so much more effective than public management. One is a natural protection against neglect. As Aristotle explained, "What belongs in common to the most people is accorded the least care." Another reason concerns the character traits brought out by private ownership and public management. As John Locke put it, private property brings out people's "Industrious and Rational" qualities, while public management encourages people to become "Quarrelsome and Contentious," arguing whether and to whom the government should give a resource up.

Although these generalizations are simple and rough, there is a lot of impressionistic evidence confirming that they're on the mark even in the particular case of shale exploration. The experience of Poland confirms the concern about neglect. The Polish government has tried to encourage shale exploration and fracturing in reserves held by the government. But (state-supported) domestic energy companies have not been adept at exploration and production; they have focused on importing oil and gas (especially from Russia). Outside companies have petitioned for exploration permits. Yet although the Polish government wants to support shale exploration, its permit reviewers have been slow and unresponsive, so subsurface hydrocarbons remain untapped.

The political climates in many other countries confirm Locke's point. In most of the rest of the world, opponents use permitting processes to slow shale exploration. Environmentalists have successfully hampered exploration this way in the United Kingdom, France, and many other European countries. Permitting processes also give local residents input, to make sure that their lands and land uses aren't threatened.

In other countries, shale exploration has also been slowed or derailed by entrenched energy companies. Quite often, state-run or state-supported producers of conventional oil or gas intervene to oppose applications to explore for shale resources; they don't want competition from alternative sources of energy. In the most colorful cases, conventional energy suppliers use environmentalist groups as fronts. Environmental non-governmental organizations have stopped shale exploration in Lithuania, Romania, Bulgaria, and Ukraine. These NGOs' efforts are suspected to have been financed by Gazprom, the Russian energy supplier. When NGOs and local environmentalists stop energy exploration on environmental grounds, they keep their local citizenries dependent on Gazprom's oil and gas. The contentious politics created by these interest groups, be they environmentally or profit-minded, keep publicly owned resources from being produced and used.

By contrast, the American common-law, private-ownership approach toward mineral rights allows private landowners to make their own choices, protect their interests, and profit from the land they own by dealing with companies directly. By law, shales and other subsurface rocks could be treated as resources separate from surface land. Yet such an approach would create many practical complications. Shale-exploration companies might fight with each other over resources, and they might disregard the concerns of surface owners about health and pollution. In most states, American common law avoids these and other complications; it not only treats the minerals as private resources, but it also bundles them into the same legal unit as the surface land. By settling mineral ownership with a clear and simple rule, it encourages energy producers to be "industrious and rational" in their negotiations with landowners—and not to undercut them or compete with each other.

That fact, if properly explained, can put a mineral lease in a different, more sympathetic light. *Gasland* and other environmentalist works make landowners seem like rubes or victims. But leasing in fact has a positive moral dimension. When an owner leases carefully and

intelligently, he exercises a property right, and he does so in a way that helps make both him and his bargaining partner happier than they were before. Landowners need to bargain carefully and remain skeptical of energy producers in addressing royalties, nuisances caused during oil and gas drilling, and other possible concerns. If owners do bargain carefully, however, they help the public by facilitating exploration that produces savings and useful goods for everyone else. And it's fair and just for them to help themselves in the process.

Some smart landowners benefit a great deal. In 2011, *Kiplinger* reported on Jeff and Pamela Barnes, a couple who leased mineral rights beneath their dairy farm in Lawrenceville, Pennsylvania. As of 2011, they were receiving $8,000 to $35,000 in royalties per month. They used these royalties to free themselves of debt, create an emergency fund in case farm equipment needed to be replaced, and start college-savings funds for their young sons. They were using their property rights as a well-designed system would suggest—and in doing so they were helping the shale revolution go forward smoothly. This is how the free exercise of property and prosperity go together, and voters ought to be reminded as much.

PROPERTY RIGHTS AND REGULATION

Natural rights of property and commerce have supported and enabled the shale revolution in the United States. The moral principles that justify those rights also justify restraints on those rights—and legal regulations to enforce the restraints. By the same token, however, those same principles also limit the acceptable goals and forms of regulation. Proponents of energy exploration and fracking must make a moral argument for distinguishing among different kinds of regulation. In a free country devoted to free enterprise, an activity should be presumed legitimate until it is proven otherwise. When restrictions can't meet that burden, they are not legitimate regulations but invasions of legitimate activity protected by basic rights.

As of now, that burden can't be met by the most controversial restrictions being advanced against shale exploration—bans and long-term moratoria. These restrictions suffer from three major problems. One is arbitrariness. Bans on fracturing are sometimes justified on the grounds that shale production accelerates climate change. We do not need to get into debates about whether climate change is occurring or how severe it is to see a serious problem with this rationale. If climate change is a

problem, it doesn't justify singling out shale oil or gas. To the extent that they're motivated by concerns about climate change, state and local bans on shale production are restricting the free exercise of some property rights without applying the same restrictions to other energy sources creating the same ostensible risk.

Second, proposed restrictions often get the burden of proof wrong. This tendency is illustrated by New York's moratorium on hydraulic fracturing, which was justified on the grounds that fracturing might threaten state fresh-water supplies. The state department of health didn't find proof that fracturing was likely to threaten fresh-water supplies; rather, it recommended that the New York governor enforce a moratorium "[u]ntil the science provides sufficient information to determine the level of risk to public health... and whether the risks can be adequately managed." In other words, the health department banned fracturing without proof one way or the other, and put the burden on energy producers to demonstrate that fracturing is safe. The department framed the issue backward. Because shale exploration constitutes the legitimate exercise of a property right, New Yorkers deserve the freedom to explore for shale resources unless the available science proves conclusively that exploration is dangerous.

The last problem is that many of the regulations run contrary to the available evidence. The best research shows that hydraulic injections don't threaten fresh-water sources. Now, the possibility does need to be considered seriously. Citizens' rights to health and secure property entitle them to be free from contamination of their drinking-water sources. Fracturing injects large quantities of pressurized water into the ground, and the additives in injection water could migrate throughout the subsurface.

But "possibility" isn't the same as "likelihood," and existing evidence doesn't suggest that fracking is contaminating fresh-water sources. To begin with, before injection fluids could reach fresh-water aquifers, they would need to travel thousands of feet upward, usually more than a mile. Furthermore, although hydraulic fracturing relies more heavily on pressurized injection than other energy exploration does, energy companies have been relying on injection in more conventional production methods since at least the 1940s. Since this use hasn't led to water contamination in the past, fracturing-based hydraulic injections should get the benefit of the doubt today.

Recent studies confirm this course of action. In 2004, in a review of existing evidence about fracturing in coal-bed-methane extraction, the EPA concluded that hydraulic injections posed little threat to underground sources of drinking water. (That study confirmed the judgment of most members of Congress that the Safe Drinking Water Act hadn't been meant to cover hydraulic injections, and helped convince them to pass the 2005 amendment so often criticized.) In 2011, the EPA issued a draft report suggesting that an aquifer beneath Pavillion, Wyoming, had been contaminated by fracturing-related hydraulic injections. The Pavillion case is often cited by fracturing critics as proof of the danger of water contamination. In 2015, however, on assignment from the EPA, the Wyoming department of environmental quality and an environmental consulting firm found it "unlikely" that fracturing water "ha[d] risen to the depths" of fresh-water wells, and a "negligible" likelihood that injections "ha[d] led to fluids interacting with . . . the study wells."

Most recently, in 2015, the EPA surveyed all the scientific literature and reported any data it could find on the dangers of hydraulic injections to fresh ground water. The EPA didn't find evidence that the "mechanisms" by which injected fluids could contaminate ground water "have led to widespread, systemic impacts on drinking water resources," and the "number of identified cases" where fresh-water sources were affected was judged "small compared to the number of hydraulically fractured wells."

This background information provides a context for talking about fracturing regulations. The possibility of water contamination justifies some regulations. State regulators may justly issue standards for how energy companies should line and seal their pipes, or how they should store fracturing fluids and flowback. In case water does get contaminated, regulators may also order energy companies to perform subsurface water tests shortly before, during, and regularly after shale exploration. But historical evidence suggests that hydraulic injections aren't inherently or regularly dangerous to underground fresh water, and more recent studies confirm as much. So when state and local governments ban or impose moratoria on hydraulic fracturing, they're not regulating the activity to protect fresh water but are instead violating property rights.

ARGUING FROM THE MORAL HIGH GROUND

The rights-based account of American property law referenced here helps explain why the shale revolution started in the United States. This

account doesn't render irrelevant any data about jobs and wealth created, but it does make it clear that those data are standing in for more significant and meaningful moral phenomena. The shale revolution is an instance of free enterprise in action. Shale explorers are discovering a resource that people find useful for a wide range of pursuits. And in their efforts to satisfy energy consumers, explorers are incidentally empowering landowners and workers as well.

This account also clarifies when shale exploration should be deemed dangerous enough to require regulation. Here, too, this account doesn't eliminate arguments about risks—say, about the likelihood of climate change or the likelihood of water contamination. But it does put those risks in a moral context. Shale exploration isn't a "mere" business activity threatening rights to a clean environment or fresh water. As non-regulation can threaten these rights, so too unfounded regulations can threaten valuable rights to property, labor, and commerce.

And more generally, this rights-based account has a reasonable prospect of improving and deepening our ongoing debates about shale production. In culture and politics, it's not enough to argue that a policy is likely to be advantageous. Voters *are* interested in whether a given activity is advantageous for themselves and their communities, and they do often understand "advantage" in hard-nosed and self-interested terms. But voters can also be impressed by news stories, movies, or political arguments suggesting that a practice is dangerous or threatening to their community's way of life. And if they're persuaded of such indictments, they won't find the activity so "advantageous" to themselves, and they may be moved more by others' concerns about wrongs or threats to the common good. The shale revolution is being criticized in these terms, and these criticisms call for a better response.

In a community in which anti-fracking rhetoric dominates, life and politics are characterized by scarcity and fears. That climate denies everyone—workers, consumers, and landowners—opportunities to help themselves. By contrast, in a system of free enterprise, owners use their land to make their own lives better, and everyone benefits when energy companies increase the supply of energy available for all. The shale revolution needs more champions who can remind American citizens why. And so does the American system of free enterprise generally.

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SUPPLEMENTARY MATERIALS

www.sciencemag.org/content/352/6281/76/suppl/DC1
Materials and Methods
Figs. S1 to S17
References (*31*–*49*)

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ATMOSPHERIC METHANE

A 21st-century shift from fossil-fuel to biogenic methane emissions indicated by $^{13}CH_4$

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Between 1999 and 2006, a plateau interrupted the otherwise continuous increase of atmospheric methane concentration [CH_4] since preindustrial times. Causes could be sink variability or a temporary reduction in industrial or climate-sensitive sources. We reconstructed the global history of [CH_4] and its stable carbon isotopes from ice cores, archived air, and a global network of monitoring stations. A box-model analysis suggests that diminishing thermogenic emissions, probably from the fossil-fuel industry, and/or variations in the hydroxyl CH_4 sink caused the [CH_4] plateau. Thermogenic emissions did not resume to cause the renewed [CH_4] rise after 2006, which contradicts emission inventories. Post-2006 source increases are predominantly biogenic, outside the Arctic, and arguably more consistent with agriculture than wetlands. If so, mitigating CH_4 emissions must be balanced with the need for food production.

Anthropogenic CH_4 emissions have almost tripled [CH_4] since preindustrial times (*1*–*3*). This contributes strongly to anthropogenic climate change through radiative forcing and impacts on atmospheric chemistry, particularly hydroxyl consumption, tropospheric ozone generation, and water vapor formation in the stratosphere (*4*). In a positive feedback to climate change, natural sources such as CH_4 hydrates, tundra, and permafrost may increase (*5*). We must therefore understand how the CH_4 budget responds to human activities and environmental change. The onset and end of the 1999–2006 [CH_4] plateau (Fig. 1) (*3*, *6*, *7*) have been studied with inverse models (top-down) (*8*–*14*), as well as process modeling (*6*, *8*, *15*–*20*) and emission estimates (bottom-up) (*21*–*23*). These approaches are either not emission-specific or uncertain in scaling and process representation (*6*). In contrast, the $^{13}C/^{12}C$ ratio in atmospheric CH_4 [$\delta^{13}C_{(Atm)}$; expressed in δ notation relative to the Vienna Pee Dee Belemnite standard] is controlled by the relative contributions from source types with distinctive isotope signatures $\delta^{13}C_{(So)}$ [biogenic ~−60 per mil (‰), such as wetlands, agriculture, and waste; thermogenic ~−37‰, such as fossil-fuels; pyrogenic ~−22‰, such as biomass burning] (*3*, *24*). Large and overlapping ranges for $\delta^{13}C_{(So)}$ in field studies of the main source types and even individual sources (such as wetlands) (*24*) average out at the global scale so that $\delta^{13}C_{(So)}$ is suitable to characterize emissions. Sink processes with characteristic isotopic fractionation ε (*25*) [for example, hydroxyl (OH) ε = −3.9‰; chlorine in the marine boundary layer (Cl-MBL) ε = −60‰; stratospheric loss ε = −3‰; or oxidation by soils ε = −20‰] (table S1) (*26*, *27*) also influence $\delta^{13}C_{(Atm)}$. Therefore, $\delta^{13}C_{(Atm)}$ variations indicate changes in CH_4 budgets, in which pertinent sources are industrial (thermogenic); agricultural, such as ruminants and rice cultivation (biogenic); and climate-dependent, such as biomass burning (pyrogenic) and natural wetlands, including freshwater and permafrost (biogenic). Other sources lack magnitude [termites, wild animals, ocean, and hydrates (*8*)] or known processes (geologic sources) to force abrupt and sustained changes (supplementary materials). Changes in the dominating OH sink may affect [CH_4] and $\delta^{13}C_{(Atm)}$ trends, whereas substantial changes in other sinks are unlikely or uncertain (supplementary materials).

We reconstructed [CH_4] and $\delta^{13}C_{(Atm)}$ time series by splicing measurements from ice cores, firn air, archived air (*1*, *2*), and global networks (Fig. 1, fig. S1, and tables S2 and S3) (*3*) (*25*). ^{13}C enrichment followed by stable $\delta^{13}C_{(Atm)}$ parallels [CH_4] trends until the end of the 1999–2006 plateau. Afterward, [CH_4] increases, whereas $\delta^{13}C_{(Atm)}$ becomes more ^{13}C-depleted. This suggests that the increasing emissions before and after the plateau differ in $\delta^{13}C_{(So)}$.

We used a one-box model (*25*, *27*) to quantify changes in the CH_4 budget. An inversion run derives the history of global emission strength and isotopic source signature [$\delta^{13}C_{(So)}$] from the [CH_4] and $\delta^{13}C_{(Atm)}$ reconstructions and specified sink parameters (tables S1 and S3). In forward mode, this "base source" as input reproduces measured [CH_4] and $\delta^{13}C_{(Atm)}$ until the start of an event (plateau or renewed increase). Afterward, the source is held constant, providing a "Stabilization Run" (Fig. 2A). A superimposed "perturbation source" then tests the effect of strengthening or weakening emissions with a prescribed perturbation $\delta^{13}C_{(So)}$ on $\delta^{13}C_{(Atm)}$. Alternatively, sink variability can be implemented for equivalent tests. The modeling design is detailed in section 1.3 of (*25*).

Stabilization Run 92 (SR92) tests whether emissions simply stabilized to cause the [CH_4] plateau (assuming constant sinks) (*28*). The base source is run from 1700 to 1992, during which time emission rates show steady trends (fig. S2); afterward, emissions are held constant at 1991–1992 rates and average 1982–1992 $\delta^{13}C_{(So)}$. These choices remove disruptions by the Mount Pinatubo eruption (supplementary materials). Model-data mismatches after the plateau onset (Fig. 2) suggest a changing source mix and emission reductions. The latter occur abruptly after 1992, for an average 7.2 to 11.2 Tg loss in annual global emissions

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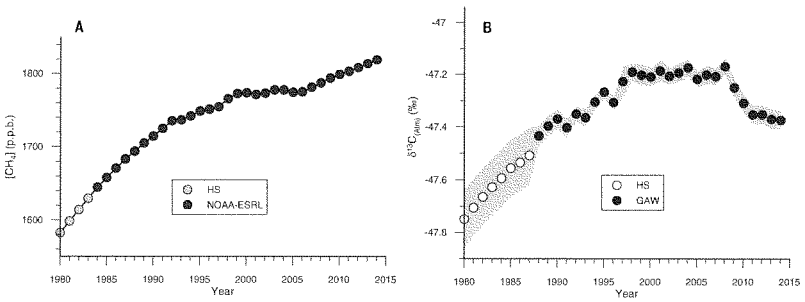

Fig. 1. Global trends in $[CH_4]$ and $\delta^{13}C_{(Atm)}$. (**A**) Spliced records of globally averaged annual values for $[CH_4]$ from a historic spline (HS) (light blue) (*1*) and the NOAA-ESRL global monitoring network (dark blue) (*3*). The uncertainty range is indicated by the thickness of the connecting line. (**B**) Spliced records of globally averaged annual values for $\delta^{13}C_{(Atm)}$ from a HS (yellow) (*2*) and atmospheric time series from contributing Global Atmosphere Watch (GAW) stations measured in our three laboratories (green). Gray shading shows the 1σ confidence interval (CI). Details on the splicing and uncertainty estimates are provided in (*25*).

over 1993–2006 relative to 1991–1992 (fig. S3). In "Perturbation Runs" (PRs92/1), this emission loss is superimposed on the SR92 source as a negative perturbation that decreases $[CH_4]$ from the SR92 values to observations (Fig. 2A). By assigning different perturbation $\delta^{13}C_{(So)}$ values in PRs92/1 to match observed $\delta^{13}C_{(Atm)}$, we fingerprinted the emissions that are no longer contributing to the total source. A perturbation $\delta^{13}C_{(So)}$ of ~–40‰ fits the plateau values within uncertainties, although without truly leveling out (Fig. 2B). The match improves for perturbation $\delta^{13}C_{(So)}$ = –53‰ for 1993–1995 and –35‰ from 1996 (PRs92/2) (Fig. 2C). Alternatively, Stabilization Run SR92/OH with OH variability, as reconstructed from methyl-chloroform (*29*), and constant 1992–2006 emissions, approximate measured $[CH_4]$ and $\delta^{13}C_{(Atm)}$ trends, so that additional source perturbations (PRs92/OH) are small and have little impact (Fig. 3). Combined OH variability and emission reductions fit observations better, but the relative weight of the two processes remains unknown, and perturbation $\delta^{13}C_{(So)}$ of –35 to –40‰ stays within uncertainties of the emissions-only scenario (figs. S4 to S7).

$\delta^{13}C_{(So)}$ ~ –35‰ is characteristic for thermogenic CH_4 (*3*, *24*, *26*), which is mainly emitted from the production of oil, natural gas, and coal (*21*, *22*). Simultaneous biogenic and pyrogenic reductions could produce the same signal as thermogenic reductions. This seems unlikely because climatic events such as El Niño–Southern Oscillation phases force opposite emission changes in wetlands (*15*)—the major biogenic source—and the total of natural and anthropogenic biomass burning (*16*). The perturbation $\delta^{13}C_{(So)}$ 1σ uncertainty (–28 to –42‰) (supplementary materials) allows for a small probability that the perturbation is pyrogenic. However, the required 20% pyrogenic drop is inconsistent with

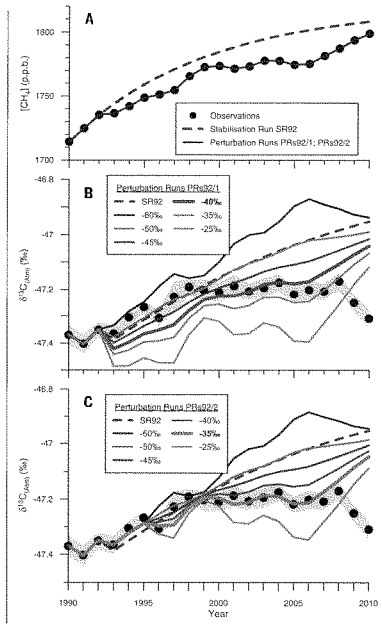

Fig. 2. Box-model results for the onset of the 1999–2006 plateau. (**A** to **C**) Observed yearly averages for $[CH_4]$ and $\delta^{13}C_{(Atm)}$ [black dots; gray shading for 1σ CI of $\delta^{13}C_{(Atm)}$]. SR92 (red dashed lines) indicates trends in $[CH_4]$ and $\delta^{13}C_{(Atm)}$ for emissions held constant at average 1991–1992 (553 Tg/year) and 1982–1992 (–53.35‰) levels, respectively. (A) Subtracting a source perturbation (yearly varying, average –9.5 Tg/year; PRs92/1 and PRs92/2) reconciles modeled $[CH_4]$ (blue line) with observations. (B) PRs92/1: $\delta^{13}C_{(Atm)}$ trends if $\delta^{13}C_{(So)}$ values between –25‰ and –60‰ (solid lines) are assigned to a set of perturbation runs starting in 1993. Thick line indicates best-fit scenario [$\delta^{13}C_{(So)}$ = –40‰] for 1999–2006 observations. (C) PRs92/2: as above, but assigning –53‰ to all perturbation runs for 1993–1995. Best-fit results from perturbation $\delta^{13}C_{(So)}$ = –35‰. Total $\delta^{13}C_{(So)}$ values for all runs are shown in fig. S14 and table S4.

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reconstructions (*8*, *17*), and the preplateau reduction did not occur in the tropics (*28*), where most pyrogenic emissions originate (*8*). Sink changes may have contributed to the $[CH_4]$ plateau, but only in concert with stagnating total emissions.

To study the renewed $[CH_4]$ rise, another Stabilization Run SR06 runs the base source until 2006 and then holds it constant at 1999–2006 averages for emission strength and $\delta^{13}C_{(So)}$. This simulates a continuation of the $[CH_4]$ and $\delta^{13}C_{(Atm)}$ plateaus (Fig. 4). Superimposed Perturbation Runs PRs06 with additional emissions averaging +19.7 Tg/year (fig. S3) [which is consistent with (*13*, *30*)] reproduce the $[CH_4]$ rise and need $\delta^{13}C_{(So)}$ ~ −59‰ (−56 to −61‰, 1σ) (supplementary materials) to match the post-2006 $\delta^{13}C_{(Atm)}$ decline (Fig. 4B). Alternatively, Stabilization Run SR06/OH includes available OH reconstructions (1994–2007; constant OH assumed afterward). Associated Perturbation Runs PRs06/OH prescribe Perturbation A (2007–2011) and Perturbation B (2011–2014) to capture the marked break in slope of 2011. Best fits for Perturbation A ~ −75‰ and Perturbation B ~ −60‰ account for a ^{13}C-rich anomaly in 2008 and match the differing $\delta^{13}C_{(Atm)}$ slopes (Fig. 4C). This scenario suffers from uncertainties regarding the transition from reconstructed to constant OH in 2007 (alternative OH trends are examined in the supplementary materials). Also, matching the 2008 $\delta^{13}C_{(Atm)}$ anomaly could skew the trend for subsequent years. The resulting bias may be seen in perturbation $\delta^{13}C_{(So)}$ ~ −75‰ for 2007–2011. Such extremely ^{13}C-depleted values are only found in some boreal biogenic sources, which are unlikely to dominate the global signal. Therefore, the more conservative result is perturbation $\delta^{13}C_{(So)}$ ~ −59‰ integrated over 2007–2014 (Fig. 4B), but during 2006–2011, $\delta^{13}C_{(So)}$ was potentially more ^{13}C-depleted, as shown in Fig. 4C. OH variability may contribute to the post-2006 event, but perturbation $\delta^{13}C_{(So)}$ remains within uncertainties of the above estimates (figs. S8 to S12).

$\delta^{13}C_{(So)}$ ~ −59‰ is characteristic for biogenic sources (*3*, *24*, *26*). Thermogenic or pyrogenic emissions would require compensating changes in other sources or sinks. An atmospheric general circulation model (AGCM)–based chemistry-transport model (ACTM) study recently found post-2006 biogenic increases relative to pyrogenic ones (*12*). That study prescribed thermogenic emissions and therefore did not test all sources independently and whether thermogenic emissions are contributing to the $[CH_4]$ growth. We calculate the possible contribution of thermogenic CH_4 in a combined increase with biogenic emissions as 0.9 ± 4.8 Tg/year (1σ) from 19.7 Tg/year total (supplementary materials). Larger thermogenic contributions require pyrogenic reductions. Process-based models (*18*) find average pyrogenic reductions by ~1.5 Tg between 1999–2006 and 2007–2014. This accommodates <5.5 Tg/year additional thermogenic emissions. However, emission inventories suggest variable (*21*) or increasing pyrogenic emissions (*22*), negating thermogenic increases. Biogenic increases and pyrogenic decreases together facilitate thermogenic contributions to the total increase of 0 to 33%. A more ^{13}C-depleted perturbation $\delta^{13}C_{(So)}$, as suggested in Fig. 4C, would lower this estimate further. In all scenarios of simultaneous pyrogenic, thermogenic, and biogenic changes, increasing biogenic emissions are causing most or all of the post-2006 $[CH_4]$ growth. This finding remains robust for potential sink changes (supplementary materials).

The global CH_4 budget is underconstrained by $[CH_4]$ and $\delta^{13}C_{(Atm)}$. We have tested concurring and compensating changes in the pertinent and better-known $[CH_4]$ sources and sinks. We cannot rule out that other combinations, or less understood processes (such as stratospheric-tropospheric exchange), explain or contribute to $\delta^{13}C_{(Atm)}$ trends. Three-dimensional inversions of regional variability in our data may provide further insights. Nevertheless, our findings allow for a likely reconstruction of recent CH_4 budget changes.

The $\delta^{13}C_{(Atm)}$ history suggests increasing ^{13}C-rich anthropogenic emissions since the industrial revolution (*2*). We show here that in the 1990s and early 2000s, ^{13}C-rich emissions likely stagnated or decreased. This signal is muted after the Mount Pinatubo eruption decreased OH and wetland emissions (*10*), as seen in model-data discrepancies (Figs. 2B and 3B) and possibly higher perturbation $\delta^{13}C_{(So)}$ (Fig. 2C) for 1993–1995. After 1995, the most parsimonious explanation for the observed emissions decrease is thermogenic reductions. Previous $\delta^{13}C_{(Atm)}$ studies provided contradicting results for thermogenic emissions (*9*, *11*, *31*); only (*11*) found reductions for ~1988–2002. Our result is consistent with combined bottom-up and top-down reconstructions finding "decreasing-to-stable" fossil-fuel sources during plateau onset (*8*). Also, ethane levels indicate declining annual thermogenic CH_4 emissions between 1984 and 2010 by >10 to 21 Tg (*32*), which is consistent with our 7.2 to 11.2 Tg/year average decrease. One possible cause is reduced fossil-fuel CH_4 emissions by 12 to 20 Tg/year through a collapse in production after the Soviet Union breakup in 1991 (*28*). Our results therefore support previous evidence for thermogenic reductions. Alternatively, OH variability with stagnant emissions provides an equally plausible explanation.

After 2006, the activation of biogenic emissions caused the renewed $[CH_4]$ rise. The exact nature of this source is less clear. Possibly, emissions from waste treatment contributed, although their $\delta^{13}C_{(So)}$ ~ −55‰ is somewhat too ^{13}C-enriched, and inventories indicate no step change around 2007 (*21*, *22*). Arctic warming could have enhanced emissions from wetlands, thawing permafrost, and CH_4 hydrates (*5*). This was detected for 2007 but not afterward (*14*). The onset of the post-2006 trend in $\delta^{13}C_{(Atm)}$ in the 60° to 90°N latitude band seems to lag other latitudes (fig. S13),

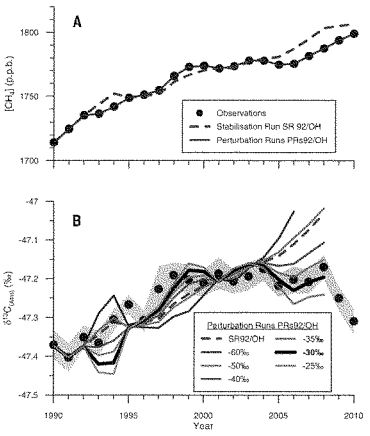

Fig. 3. OH-variability scenario for the onset of the 1999–2006 plateau. Symbols are as in Fig. 2. (**A** and **B**) SR92/OH (red dashed lines) includes OH variability (*29*) for 1994–2007, in addition to constant emissions after 1992 at average 1991–1992 and 1982–1992 levels for emission strength and $\delta^{13}C_{(So)}$, respectively. (A) In SR92/OH, sink variability (*29*) produces $[CH_4]$ close to observations, leaving little room for source perturbations in PRs92/OH (average −2.6 Tg/year; blue line). This results from an OH-induced trend to lower atmospheric CH_4 residence time τ for 1993–1999, whereas the longer-term average (1993–2007) of τ is almost identical to the value used for the runs in Fig. 2. (B) PRs92/OH: best fit is for perturbation $\delta^{13}C_{(So)}$ = −30‰, but $\delta^{13}C_{(Atm)}$ trends for values between −25‰ and −50‰ all fit observations throughout most of the 1993–2006 perturbation period because OH variability and the associated changes in ε and τ alone can account for observed $[CH_4]$ and $\delta^{13}C_{(Atm)}$ trends. Total $\delta^{13}C_{(So)}$ values for all runs are shown in fig. S14 and listed in table S4.

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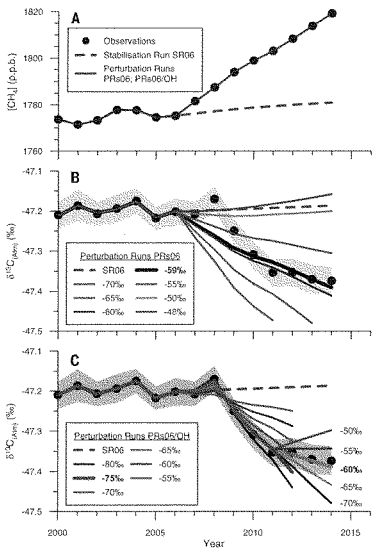

Fig. 4. Box-model results for the $[CH_4]$ increase after 2006. Symbols are as in Fig. 2. (**A** to **C**) Two Stabilization Runs (red dashed lines) SR06 [(A) and (B)] and SR06/OH [(A) and (C)] produce the same trend in $[CH_4]$, but different $\delta^{13}C_{(Atm)}$ for emissions held constant at average 1999–2006 levels from 2007 on. (A) PRs06 and PRs06/OH (yearly varying with average 19.7 Tg/year) reconcile modeled $[CH_4]$ (blue line) with observations. (B) $\delta^{13}C_{(Atm)}$ trends for PRs06 with perturbation $\delta^{13}C_{(So)}$ values between −70‰ and −45‰. The thick line indicates best fit scenario for $\delta^{13}C_{(So)}$ = −59‰. (C) PRs06/OH for a combined scenario that includes (i) OH reconstructions (*29*) when available (1994–2007, no OH variability afterward); (ii) Perturbation A for 2007–2011 overlain on the OH variability (blue and orange lines), best fit for perturbation $\delta^{13}C_{(So)}$ = −75‰ (magenta line); and (iii) Perturbation B for 2011–2014 (green lines, using best-fit Perturbation A until 2011), best fit for perturbation $\delta^{13}C_{(So)}$ = −60‰ (bright green line). Total $\delta^{13}C_{(So)}$ values for all runs are shown in fig. S15 and table S4.

and post-2006 emissions rose mostly in the tropics, as shown in satellite CH_4 measurements (*13*). This footprint and the perturbation $\delta^{13}C_{(So)}$ fit tropical wetlands and agricultural emissions. Natural wetlands, the single largest CH_4 source, have been implicated in the post-2006 $[CH_4]$ growth (*8*, *14*) under enduring La Niña conditions (*33*). The associated combination of higher wetland (*15*) and lower pyrogenic emissions (*16*) could explain strongly ^{13}C-depleted perturbations $\delta^{13}C_{(So)}$ for 2007–2011 (Fig. 4C). However, tropical wetland emissions are higher in the southern hemisphere (*19*), whereas remote sensing shows that $[CH_4]$ increased mainly in the northern tropics and subtropics (*13*). Also, tropical wetlands are relatively ^{13}C-enriched (−52 to −60‰) and match our post-2006 perturbation not as well as rice cultivation (−59 to −65‰) and C_3-fed ruminants (−60 to −74‰) (*3*, *24*, *26*). This isotopic evidence against tropical wetlands is not strong, given the ranges of reported $\delta^{13}C_{(So)}$ for various sources. However, sustained source ^{13}C-depletion over 7 years with the potential for strong ^{13}C-depletion until 2011 is harder to reconcile with tropical wetlands as compared with other biogenic emissions, such as agricultural ones. Inventories report increased annual agricultural emissions over the 2000–2006 average of ~12 Tg by 2011, dominated by ruminants (*21*, *23*). This can largely account for the post-2006 $[CH_4]$ growth, estimated at 15 to 22 Tg/year (*30*). Also, India and China's dominance in livestock emissions (*23*) and Southeast Asian rice cultivation are consistent with the location of the source increase (*13*). Although we cannot identify the specific biogenic source driving the $[CH_4]$ increase with certainty, it is compatible with agricultural emissions. If so, feedbacks between climate change and natural CH_4 emissions (*5*) are not yet evident.

The finding of a predominantly biogenic post-2006 increase is robust. Further, it seems likely that fossil-fuel emissions stagnated or diminished in the 1990s. They are a minor contributor to the renewed $[CH_4]$ rise. This contradicts emission inventories reporting increases of all source types between 2005 and 2010 with a major (~60%) thermogenic contribution (*21*, *22*). The predicted $\delta^{13}C_{(So)}$ ~ −48‰ (or more ^{13}C-enriched) produces a slight $\delta^{13}C_{(Atm)}$ increase that cannot be reconciled with the measured marked decline (Fig. 4B). The finding is unexpected, given the recent boom in unconventional gas production and reported resurgence in coal mining and the Asian economy (*21*, *22*). Our isotope-based analysis suggests that the $[CH_4]$ plateau marks not a temporary suppression of a particular source but a reconfiguration of the CH_4 budget. Either food production or climate-sensitive natural emissions are the most probable causes of the current $[CH_4]$ increase. These scenarios may require different mitigation measures in the future.

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INSTAAR are also available from ftp://aftp.cmdl.noaa.gov/data/trace_gases. Data from Heidelberg University are available from http://www.iup.uni-heidelberg.de/institut/forschung/groups/kk/en/Data_html. Data measured by University of Washington and University of California, Irvine, were taken from http://cdiac.ornl.gov/ndps/quay.html and http://cdiac.ornl.gov/epubs/db/db1022/db1022.html, respectively. Yearly $\delta^{14}C$ values for individual stations and global annual averages are presented in tables S3 and S4. This research was supported by the Marsden Fund Council from New Zealand Government funding, administered by the Royal Society of New Zealand. Further support came from NIWA under Climate and Atmosphere Research Programme CAAC1504 (2014/15 SCI). The authors declare no competing interests. H.S. designed the data analysis; C.W.B., T.M.B., R.J.M., J.B.M., D.C.L., B.H.V., C.V., and S.E.M. performed $\delta^{14}C$ measurements; C.V., J.B.M., I.L., D.C.L., and J.W.C.W. designed sampling and analytical programmes and performed data quality control; E.J.D. provided $[CH_4]$ data; K.R.L. and H.S. designed the box model; S.E.M.F. and H.S. performed uncertainty analyses; and all authors contributed to the interpretation and the writing of the manuscript.

SUPPLEMENTARY MATERIALS

www.sciencemag.org/content/352/6281/80/suppl/DC1
Materials and Methods
Supplementary Text
Figs. S1 to S21
Tables S1 to S5
References (34–47)

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CLIMATE CHANGE

Consistent response of bird populations to climate change on two continents

Philip A. Stephens,[1] Lucy R. Mason,[2] Rhys E. Green,[2,3] Richard D. Gregory,[2] John R. Sauer,[4] Jamie Alison,[5] Ainars Aunins,[6] Lluís Brotons,[7,8,9] Stuart H. M. Butchart,[9,10] Tommaso Campedelli,[11] Tomasz Chodkiewicz,[12] Przemysław Chylarecki,[13] Olivia Crowe,[14] Jaanus Elts,[15,16] Virginia Escandell,[17] Ruud P. B. Foppen,[18,19,20] Henning Heldbjerg,[21] Sergi Herrando,[22] Magne Husby,[23] Frédéric Jiguet,[24] Aleksi Lehikoinen,[25] Åke Lindström,[26] David G. Noble,[27] Jean-Yves Paquet,[28] Jiri Reif,[29,30] Thomas Sattler,[31] Tibor Szép,[32] Norbert Teufelbauer,[33] Sven Trautmann,[34] Arco J. van Strien,[35] Chris A. M. van Turnhout,[19,20] Petr Vorisek,[30,36] Stephen G. Willis[1]*

Global climate change is a major threat to biodiversity. Large-scale analyses have generally focused on the impacts of climate change on the geographic ranges of species and on phenology, the timing of ecological phenomena. We used long-term monitoring of the abundance of breeding birds across Europe and the United States to produce, for both regions, composite population indices for two groups of species: those for which climate suitability has been either improving or declining since 1980. The ratio of these composite indices, the climate impact indicator (CII), reflects the divergent fates of species favored or disadvantaged by climate change. The trend in CII is positive and similar in the two regions. On both continents, interspecific and spatial variation in population abundance trends are well predicted by climate suitability trends.

Evidence that climate change is affecting biodiversity is accumulating (*1*). Most of this evidence reveals impacts on natural populations in the form of shifts in geographic ranges, changes in abundance, or changes in individual behavior or physiology (*2*, *3*). Meta-analyses have identified widespread changes, consistent with expectations, in both the distribution of populations and the timing of events in the annual cycles of organisms (*4*–*6*). A growing body of evidence also suggests that morphological changes are a common response to altered climates (*7*, *8*). However, despite some clear cases of climate-caused alterations of local population dynamics (*9*, *10*), multispecies, large-scale analyses of population responses to global climate change are rare (*11*, *12*).

One way to assess widespread population responses to anthropogenic drivers is to derive indicators from composite trends of species' abundance (*13*). Multispecies indicators are now widely used to aggregate biodiversity information in a way that is understood by policy-makers and members of the public, enabling evaluations of progress toward biodiversity targets (*14*, *15*). Less frequently, differences in composite trends for groups of species differentially affected by change are used to highlight the role of specific drivers of abundance. For example, large-scale aggregated trends in European species' abundance have been linked to expected future changes in climatic suitability within the region to produce composite trends for species that are expected either to gain or to lose climatically suitable range in the future (*16*). One shortcoming of that approach is that relating changes in a species' population at a subcontinental level to climate change ignores important information about variation in population trends in different areas within the subcontinent. A species showing climate-driven decline at the low-latitude range margin but climate-driven increase at its poleward range margin (*17*) might not show a clear overall trend in abundance across its range. Furthermore, accounting for spatial variation in species' population trends will reduce covariation between climate change and land-use change (*18*).

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Science
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A 21st-century shift from fossil-fuel to biogenic methane emissions indicated by $^{13}CH_4$

Hinrich Schaefer, Sara E. Mikaloff Fletcher, Cordelia Veidt, Keith R. Lassey, Gordon W. Brailsford, Tony M. Bromley, Edward J. Dlugokencky, Sylvia E. Michel, John B. Miller, Ingeborg Levin, Dave C. Lowe, Ross J. Martin, Bruce H. Vaughn and James W. C. White (March 10, 2016)

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Editor's Summary

Getting a rise out of agriculture

Methane, a powerful and important greenhouse gas, has been accumulating nearly uninterruptedly in the atmosphere for the past 200 years, with the exception of a mysterious plateau between 1999 and 2006. Schaefer *et al.* measured methane's carbon isotopic composition in samples collected over the past 35 years in order to constrain the cause of the pause. Lower thermogenic emissions or variations in the hydroxyldriven methane sink caused the plateau. Thermogenic emissions didn't resume to cause the subsequent rise. Instead, the ongoing rise is most likely due to biogenic sources, most notably agriculture.

Science, this issue p. 80

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RECOMMENDED PRACTICES

WANTED

CONSERVATION CORNER

20 Obama Administration Quotes About U.S. Shale

January 20, 2015

Tonight, President Obama will address the nation in his annual State of the Union Address. With an inevitable focus on America's outlook, here's what the President and key members of his administration have said about safe and responsible natural gas development, which is a powerful engine for job growth and opportunity.

ECONOMIC GROWTH

- **President Obama:** "America is closer to energy independence than we've been in decades." (U.S. News & World Report, 1/28/14)
- **President Obama:** "After years of talking about it, we are finally poised to control our own energy future. We produce more natural gas than ever before – and nearly everyone's energy bill is lower because of it. ... The natural gas boom has led to cleaner power and greater energy independence. We need to encourage that." (State of the Union address, 2013)
- **Secretary Moniz:** "This natural gas revolution is driving economic growth across the country, lowering energy prices and creating jobs." (Department of Energy, 7/29/14)
- **Secretary Moniz:** "Obviously, it's a huge economic benefit." (New York Daily News op-ed, 9/23/13)
- **Vice President Joe Biden:** "You all know about the Marcellus Shale — I think you heard of that, right? There's an energy boom that's changed the paradigm of manufacturing. It's cheaper to manufacture in the United States than it is in Europe and/or in Asia." (Remarks, 4/16/14)

JOB CREATION

- **President Obama:** "Our 100-year supply of natural gas is a big factor in drawing jobs back to our shores. Many are in manufacturing – the quintessential middle-class job." (Remarks, 10/2/14)
- **President Obama:** "American manufacturing has added more than 700,000 new jobs. It's growing almost twice as fast as the rest of the economy." (Remarks, 10/2/14)
- **President Obama:** "We've got to tap into this natural gas revolution that's bringing energy costs down in this country, which means manufacturers now want to locate here because they're thinking that we've got durable, reliable supplies of energy." (Remarks, 7/25/13)
- **President Obama:** "The bottom line is, natural gas is creating jobs. It's lowering many families' heat and power bills." (NY Daily News editorial, 9/29/13)

SAFE AND RESPONSIBLE

- **Interior Secretary, Sally Jewell:** "[Fracking] has been done for decades and has the potential for developing significant domestic resources and strengthening our economy and will be done for decades to come." (U-T San Diego, 8/5/13)
- **Secretary Jewell:** "There is a lot of misinformation about fracking." (KQED, 1/2/15)
- **Former Interior Secretary, Ken Salazar:** "I would say to everybody that hydraulic fracking is safe." (Washington Examiner, 9/24/13)
- **Former Energy Secretary, Steven Chu:** Shale development and hydraulic fracturing "is something you can do in a safe way." (Washington Examiner, 9/24/13)

ENVIRONMENTAL BENEFITS

- **Secretary Moniz:** "Since 2007, we have seen a 10 percent decline in carbon emissions. About half of that is due to efficiency gains and growing electricity generation from natural gas." (Dept. of Energy, 7/29/14)
- **Secretary Moniz:** "[Fracking has] been a big contributor to our carbon reduction." (NY Daily News op-ed, 9/23/13)
- **President Obama:** "We should strengthen our position as the top natural gas producer because...it not only can provide safe, cheap power, but it can also help reduce our carbon emissions." (Bloomberg News, 6/25/13)
- **President Obama:** "We produce more natural gas than any country on Earth. ... We want to make sure that —

• **U.S. EPA Administrator, Gina McCarthy:** "Responsible development of natural gas is an important part of our work to curb climate change and support a robust clean energy market at home." (The Hill, 8/14/13)

STRENGTHENED SECURITY

• **President Obama:** "Today, the number one oil and gas producer in the world is no longer Russia or Saudi Arabia; it's America." (Remarks, 10/2/14)

• **President Obama:** "We produce more natural gas than any country on Earth." (Remarks, 7/25/13)

Follow tonight's #SOTU coverage on Twitter by connecting with @MarcellusGas.

Filed Under: Blog
Tagged With: American energy, Dr. Ernest Moniz, Marcellus Shale, natural gas, State of the Union Address

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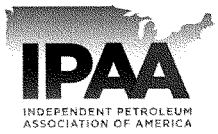

December 4, 2015

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

VIA ELECTRONIC MAIL

Re: Comments for Three Regulatory Proposals issued September 18, 2015:

1) **Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (80 Fed. Reg. 56,593)**

2) **Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry (80 Fed. Reg. 56,577)**

3) **Source Determination for Certain Emission Units in the Oil and Natural Gas Sector (80 Fed. Reg. 56,579)**

Dear Administrator McCarthy:

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC) (collectively, IPAA/AXPC).[1]

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will most directly be impacted by the U.S. Environmental Protection Agency (EPA) policy decisions to regulate methane directly from the oil and natural gas sector. Independent producers develop about 95 percent of American oil and gas wells, produce 54 percent of American oil, and produce 85 percent of American natural gas. Historically, independent producers have invested over 150 percent of their cash flow back into domestic oil and natural gas development to find and produce more American energy. IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.

AXPC is a national trade association representing 30 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and production of oil and natural gas. Moreover, our members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying innovative and

[1] For ease of reference, these comments include an Acronym Index, attached hereto as "Attachment A."

advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from unconventional sources.

Additionally, they are joined by the American Association of Professional Landmen (AAPL), the Association of Energy Service Companies (AESC), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment & Services Association (PESA), the US Oil & Gas Association (USOGA), 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 will be most significantly affected by the actions resulting from these regulatory proposals. In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments. IPAA/AXPC also endorses and supports the comments of the Western Energy Alliance (WEA) and the American Petroleum Institute (API) submitted on the proposed rules referenced above.

As an initial matter, these comments are designed to address the three aforementioned proposed regulatory actions simultaneously and will be submitted to all three dockets as all three proposals target the oil and natural gas industry, and certain responses and arguments from IPAA/AXPC are applicable to all of the proposals. Additionally, comments on all three proposals were initially due November 17, 2015. IPAA requested an extension of the 60-day comment period on October 2, 2015, due to the complexity and breadth of the proposed regulations and that certain key supporting documents were not available in the docket for public review when the EPA published the proposals in the Federal Register on September 18, 2015. In late October/early November various informed parties who had requested additional time to comment learned that they would have until December 4, 2015. On November 13, 2015, the extension was published in the Federal Register.

EXECUTIVE SUMMARY

These comments raise a number of key issues associated with EPA's proposals for Clean Air Act (CAA or Act) New Source Performance Standards (NSPS), Control Technique Guidelines (CTG) and Source Determination for oil and natural gas production facilities.

EPA justifies its proposals in the context of the Administration's Climate Action Plan with a specific target of reducing methane emissions from the oil and natural gas sectors by 40-45 percent during the time period from 2012 through 2025. However, as these comments demonstrate, EPA's proposals are unnecessary, unjustified, poorly developed and counterproductive.

First, the Administration proclaims its intent to reduce methane emissions by 40-45 percent from the oil and natural gas sectors. At the same time, it takes credit for its 2012 volatile organic chemical/methane emissions regulations in these sectors that exceed its own target. Moreover, it fails to recognize that much of the reduction it seeks has occurred since 2012 from voluntary industry actions. The oil and natural gas production sector is 1.07 percent of the national Greenhouse Gas Inventory and its methane emissions will continue to drop because of industry emissions management. Consequently, any justification for additional regulation must

be thoroughly weighed based on cost effectiveness and economic consequences. EPA's proposals fail these tests.

Second, within the NSPS proposal, the most egregious element is the proposed fugitive emissions regulations that are based on purely speculative emissions reductions but, as designed, are excessively and unnecessarily burdensome. Oil and natural gas production fugitive emissions management is an emerging arena with companies and state regulatory programs still learning how best to efficiently and effectively control them. Several states are currently

be thoroughly weighed based on cost effectiveness and economic consequences. EPA's proposals fail these tests.

Second, within the NSPS proposal, the most egregious element is the proposed fugitive emissions regulations that are based on purely speculative emissions reductions but, as designed, are excessively and unnecessarily burdensome. Oil and natural gas production fugitive emissions management is an emerging arena with companies and state regulatory programs still learning how best to efficiently and effectively control them. Several states are currently implementing programs; none of which parallel EPA's proposals. Experience with those state efforts demonstrates that emissions patterns result from a few high emissions sources that can be managed quickly with sustained reductions. EPA's proposal to lock in an unworkable program for at least 5 years is arbitrary and inappropriate. EPA should await the analysis of state programs to determine whether an NSPS is logical or necessary.

Third, EPA also proposed a volatile organic compound (VOC) CTG for Ozone nonattainment areas. This proposal fails to comply with the Agency's fundamental responsibility of developing Reasonably Available Control Technology (RACT). Instead, EPA largely transposes the same requirements in the 2012 NSPS and those proposed in this regulatory action from new sources to existing ones. In doing so, EPA fails to determine whether these new facility requirements are economically appropriate as CTG for existing sources on a national basis.

Fourth, by linking its CTG proposal to its Climate Action Plan, EPA fails to address the need for the CTG with regard to Ozone nonattainment. Yet, the threshold question for these regulations is whether they are necessary and appropriate for attainment of the Ozone National Ambient Air Quality Standards (NAAQS). If fact, based on EPA's analysis of the regulatory framework to attain the recently revised Ozone NAAQS, EPA demonstrates the CTG are wholly unnecessary. Prior to proposing these CTG, EPA concluded that all but a few areas of the country will meet the new Ozone NAAQS by 2025 using national, federal regulatory requirements. Consequently, for these areas, the proposed CTG are excessive regulations. For the remaining enduring Ozone nonattainment areas, if there are oil and natural gas production operations that need to be addressed, they can be managed through local determinations of Reasonably Available Control Measures (RACM) and do not require CTG.

Fifth, because these CTG are unnecessary, their likely impact will be the inappropriate restriction of economic growth in Ozone nonattainment areas. Given that EPA has concluded that Ozone NAAQS attainment will be achieved without these CTG, these CTG will remove emissions that could be used as CAA required new source offsets. Therefore, they would unnecessarily impede economic growth that would otherwise occur.

Sixth, in its proposal to address Source Determination for oil and natural gas production facilities, EPA should recognize that new facilities should be based on a narrow definition that hones closely to the approach EPA has used under the National Emissions Standards for Hazardous Air Pollutants (NESHAP) program. Where there are issues regarding scope, the source determination should be based on the sites being contiguous in addition to sharing the same Standard Industrial Classification (SIC) Code and being under common control.

These comments will expand on the issues raised above and other more specific ones. Ultimately, however, IPAA/AXPC argues that EPA's NSPS and CTG proposals must be withdrawn, reconsidered and revised to be consistent with the Administration's own Climate Action Plan objectives and its assessment of the capability of the nation to meet the revised Ozone NAAQS. To do otherwise would arbitrarily impose excessive regulation on the oil and natural gas setoff for no purpose other than to expand the already burdensome federal regulatory program.

I. EPA's Additional New Source Performance Standards for the Exploration and Production Segment and Control Technique Guidelines for Existing Sources are Unnecessary and Misplaced.

EPA's proposed NSPS targeting methane emissions from the exploration and production segment of the oil and natural gas sector are unnecessary, unwarranted, and wasteful – not only to those subject to the regulations but to the state and federal regulators who must implement the rules if EPA does not change its course. Similarly, proposing essentially the same set of controls on existing sources in nonattainment areas (and ozone transport regions) using the proposed CTG with no additional economic justification/cost-benefit analysis is one more indication that EPA is rushing to judgment with its latest salvo of regulations. In April 2014, EPA acknowledged the lack of knowledge to regulate a variety of sources and implemented a White Paper process that sought additional technical information on a variety of sources.[2] Industry raised numerous concerns regarding EPA's lack of data regarding emissions from these sources and the cost/effectiveness of controls from these sources. Nonetheless, EPA proceeded headlong to promulgate its methane NSPS – relying heavily on the Regulatory Impact Analysis (RIA) from the VOC NSPS promulgated in 2012. The methane regulations need to "stand on their own" and be justified on their own, not simply as an "add-on" to the VOC NSPS.

These regulations will have a serious negative economic impact on American oil and natural gas production while providing marginal environmental benefit beyond the regulations EPA promulgated in 2012 to regulate VOCs from essentially the same set of production and exploration emission sources.[3] To understand the full impact, it is essential to put the entire issue in perspective.

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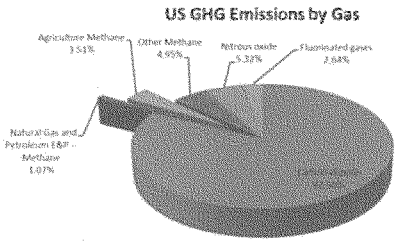
[2] U.S. Environmental Protection Agency, Section on Oil and Natural Gas Air Pollution Standards, *Methane*, *available at* http://www3.epa.gov/airquality/oilandgas/methane.html.

[3] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

From 2008 through 2013, U.S. shale gas production grew 400 percent,[4] while methane emissions have declined 13.3 percent. According to 2013 EPA Greenhouse Gas (GHG) Reporting data, methane emissions from oil and natural gas exploration and production are 1.07 percent of total U.S. GHG emissions. Further reductions will occur because of "green" or "reduced emission completions" that are being phased-in through the 2012 regulations.[5] According to EPA's latest GHG Reporting Program: "[In 2013] reported methane emissions from petroleum and natural gas systems sector have decreased by 12 percent since 2011, with the largest reductions coming from hydraulically fractured natural gas wells, which have decreased by 73 percent during that period. EPA expects to see further emission reductions as the agency's 2012 standards for the oil and gas industry become fully implemented."[6] These reductions are remarkable, given that a major component of the 2012 standards, the reduced emission completion requirements, only became effective January 1, 2015.



In January 2015, the Administration announced its intent to initiate rulemaking to further reduce methane emissions from oil and natural gas systems, including the production sector.[7] Specifically, it announced a target of a 40-45 percent reduction in 2012 emissions by 2025. For the production and exploration segment of the oil and natural gas sector, additional regulations are unnecessary. As the Administration observed in its announcement:

> In 2012, the Environmental Protection Agency (EPA) laid a foundation for further action when it issued standards for volatile organic compounds (VOC) from the oil and natural gas industry. These standards, when fully implemented, are expected to reduce 190,000 to 290,000 tons of VOC and decrease methane

[4] U.S. Energy Information Administration, *available at* http://www.eia.gov/dnav/ng/hist/res_epg0_r5302_nus_bcfa.htm.

[5] In 2012, EPA finalized a Clean Air Act (CAA or Act) Section 111(b) NSPS targeting VOCs emissions from hydraulically fractured natural gas wells. This rulemaking also reduces methane emissions as co-benefit. Methane and VOCs are emitted from oil and natural gas production facilities at the same time from the same equipment. Consequently, reducing one also reduces the other. The effects of the 2012 NSPS are still unfolding.

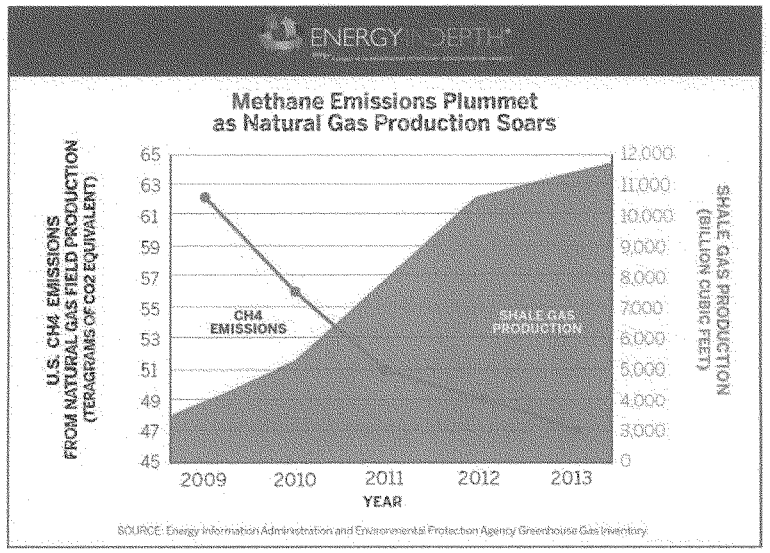
[6] Requirements for reduced emission completions on natural gas wells were promulgated in August 2012 but did not become effective until January 1, 2015. Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards, 79 Fed. Reg. 79,018 (Dec. 31, 2014) (codified at 40 C.F.R. pt. 60).

[7] Press Release, The White House, Fact Sheet: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

> emissions in an amount equivalent to 33 million tons of carbon pollution per year.[8]

Over 99 percent of the EPA projected reductions occur from the exploration and production sector. In 2013, exploration and production emissions of methane were 71 million tons of CO_2 equivalent. Consequently, by EPA's own numbers, the 2012 NSPS regulations will reduce emissions by 46 percent. This reduction exceeds the emissions target percentage of the production sector of the oil and natural gas industry.

EPA attempts to argue that its regulations are needed because methane emissions "are projected to increase by about 25 percent over the next decade if additional steps are not taken to reduce emissions from this rapidly growing industry."[9] Yet, this statement is wholly inconsistent with the experience over the past several years in the exploration and production sector of the industry. This segment has demonstrated that growth in production not only provides more clean-burning, GHG-reducing product, it has been done while reducing methane emissions as the following graphic shows:



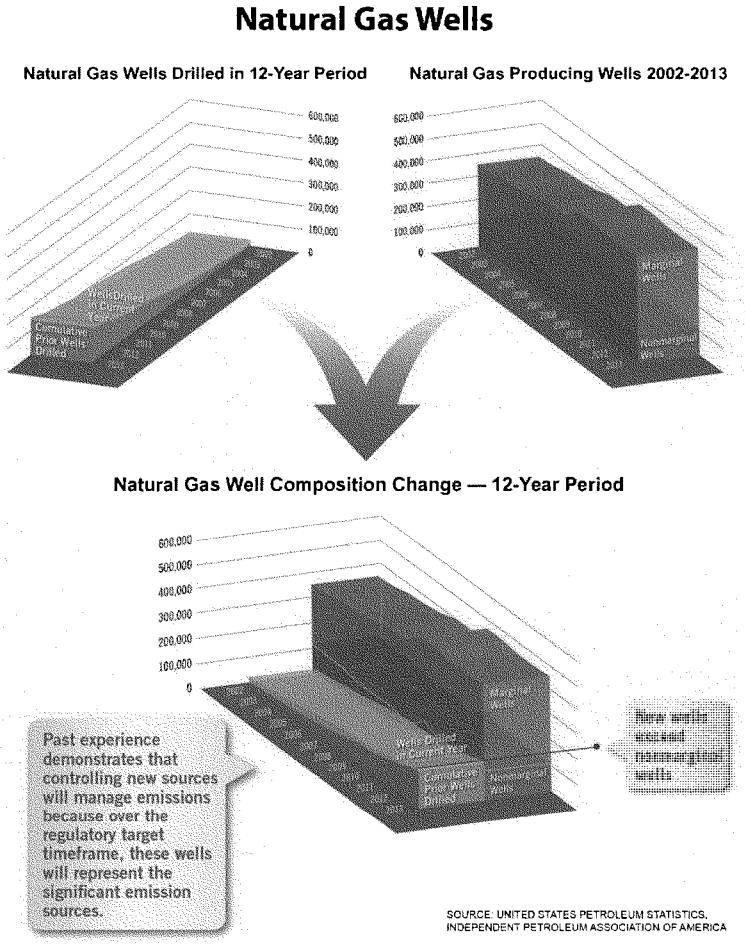
[8] *Id.*

[9] U.S. Environmental Protection Agency, Fact Sheet: EPA's Strategy for Reducing Methane and Ozone-Forming Pollution from the Oil and Natural Gas Industry (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

Significantly, these reductions in methane emissions have occurred prior to full implementation of the 2012 NSPS.

Moreover, because of the nature of oil and natural gas production, the application of controls on new sources will achieve the Administration's objectives without the need to create extensive existing source regulations. Oil and natural gas production operations differ from other types of manufacturing. After the period of initial production, wells begin to decline – generally referred to as the "production decline curve." And as the production of the well declines, its ability to emit VOCs and methane into the atmosphere also declines. Emissions from these older wells will be a smaller portion of the 1.07 percent of emissions, yet EPA's decision to regulate methane directly under Section 111(b) of the CAA and proposed CTG subjects tens of thousands of existing wells to regulation. IPAA/AXPC questions the cost-effectiveness of the proposed requirements to existing sources. The regulatory burden on state and federal regulators of exposing hundreds of thousands of existing sources is completely overlooked in EPA's proposal.

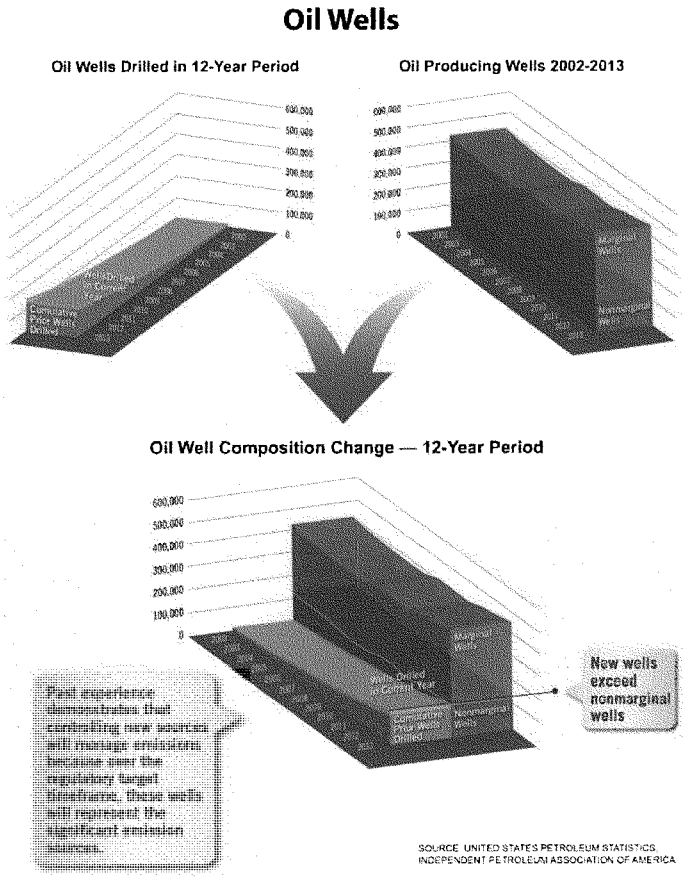
The declining nature of oil and natural gas wells also differentiates the exploration and production segment of the oil and natural gas sector from other segments further downstream where emissions remain fairly constant overtime. Ultimately, the production from the "new" wells declines to the point where they become "marginal" wells. These are defined as wells that produce 15 barrels/day of oil or less and 90 mscf/d or less of natural gas. Currently, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells. However, these small individual wells account for about 20 percent of U.S. oil production and 13 percent of its natural gas production. Consequently, unlike manufacturing facilities where new facilities do not replace existing ones, in the oil and natural gas production industry, the implementation of technology on new wells will rapidly result in its application across the breadth of the industry as new wells become the predominant source of emissions for the industry. This can be understood by looking at past experience as shown in the graphs below:



As this graphic demonstrates, after 12 years wells subject to the new source regulatory requirements will dominate the production of natural gas, and the remaining wells will be marginal wells with minimal incremental emissions beyond the emissions from sources already subject to regulation. The cost associated with reducing those incremental emissions will be greater than the cost of implementing controls on new or modified sources and will likely make many of the marginal wells uneconomic, causing them to be shut in/abandoned. The opportunity

cost or value of that last production is not offset by the minimal emissions reductions achieved by regulating existing sources.

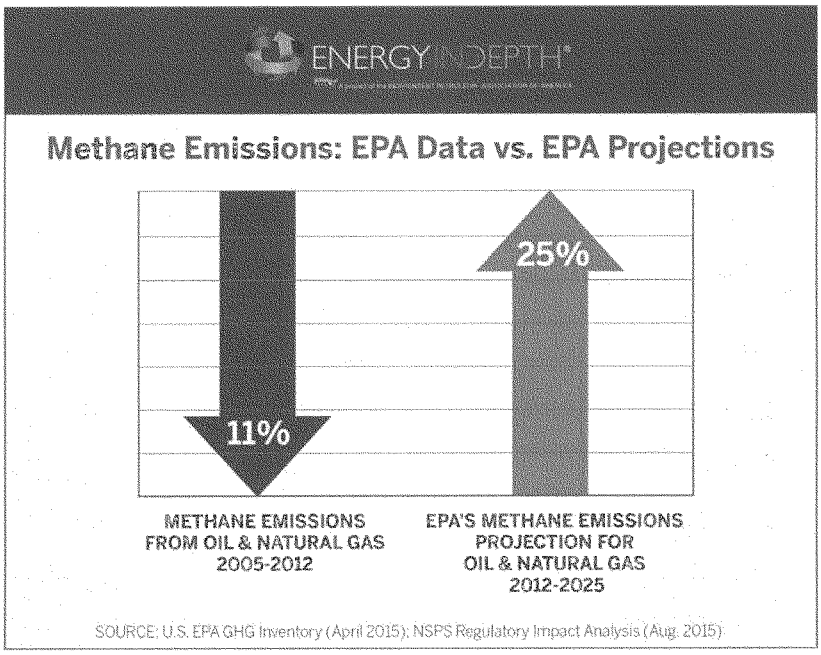
A similar pattern exists for oil wells as shown below:



While this analysis is based on past experience, if it were expanded to a 20-year period, it would show a similar trend and demonstrate that the use of new source regulations are more than adequate to address the Administration's interest in reducing methane emissions from the oil and natural gas sector, in general, and the exploration and production segment, in particular. EPA

has failed to adequately account for and justify subjecting existing exploration and production sources to regulation under Section 111 of the CAA or through the CTG.

As Energy In Depth (a research, education, and public outreach campaign supported by IPAA) recently reported, EPA's assumptions regarding methane emissions from the oil and natural gas industry are not supported by EPA's own data.

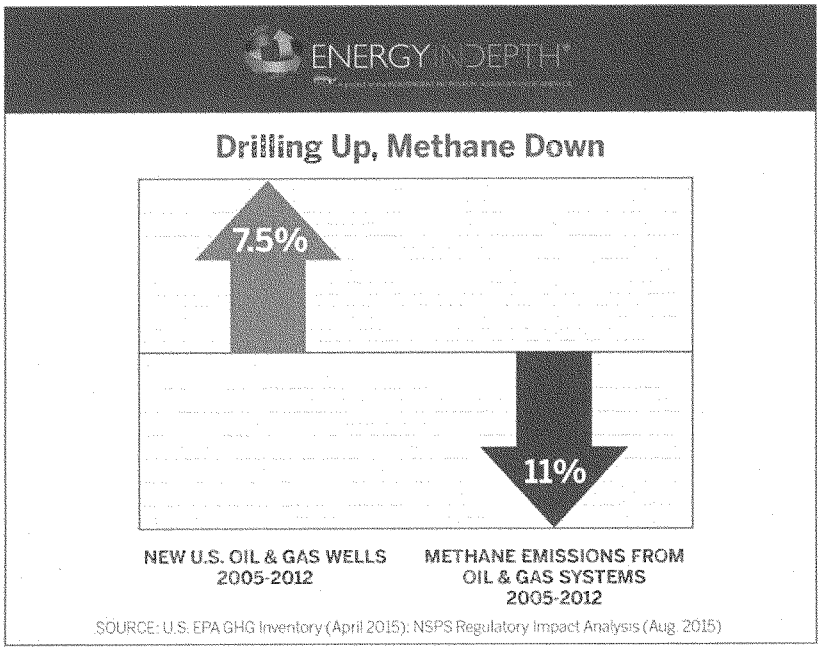


More specifically, Energy In Depth found:

- EPA projects methane emissions from the oil and natural gas sector will increase over the next decade, but **methane emissions from that sector have declined by more than 22 million metric tons** since 2005.
- Over the past decade, the United States added more than 86,000 new wells, during which **methane emissions from petroleum and natural gas systems fell by 11 percent.**
- EPA's flawed assumptions on methane emissions raise questions about the agency's cost-benefit calculation, and EPA could be **underestimating engineering costs by more than $10 million.**

- The EPA could also be **overstating the climate benefits of the rule**, since methane emissions may be significantly lower than EPA's projections.[10]

As discussed below, EPA's economic justification for it proposed regulations is problematic. But even the past does not support EPA's fundamental assumption that more drilling means more emissions:



EPA has projected that an increase in oil and natural gas activity will result in a 25 percent increase in methane emissions. But since 2005, methane emissions from U.S. oil and natural gas systems have fallen by a greater percentage than the number of new wells drilled.

IPAA/AXPC has repeatedly told EPA that additional regulation is not needed. Market forces drive the industry to minimize emissions. Unlike certain "products" in other industries with "emissions" that are a by-product or negative externality associated with the production, the "emission" of concern to EPA is the very product this industry brings to the market.

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[10] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/. IPAA/AXPC incorporate by reference the entire Energy In Depth article as part of its comments.

II. The Industry's Recent Past is Not Its Prologue – Therefore EPA's Proposed Regulations are Not Justified

EPA justifies its proposed regulations in large part on the last 10 years of growth in the American oil and natural gas industry – perhaps the most dynamic and rapid growth period in the history of the industry:

> The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year increases over the past ten years in the Inventory. New and modified hydraulically fractured oil well completions and well sites are based on projections and growth rates consistent with the drilling activity in the 2014 Annual Energy Outlook."[11]

As much as the oil and natural gas sector would like to see that growth rate continue to 2025, it simply will not happen, and the past few years illustrate the cyclical nature of the industry. The price of oil and natural gas has plummeted unlike EPA's hypothetical projections. Operators react quickly to market forces and in many shale plays very few wells are being drilled. For many small, independent operators in various plays, they have not drilled a well in 3 or more years – yet EPA is justifying the cost of the proposed regulations on the most rapid expansion in the history of the industry. The following charts from a recent article by Energy In Depth,[12] based on EIA data, clearly illustrate the impact of market forces:

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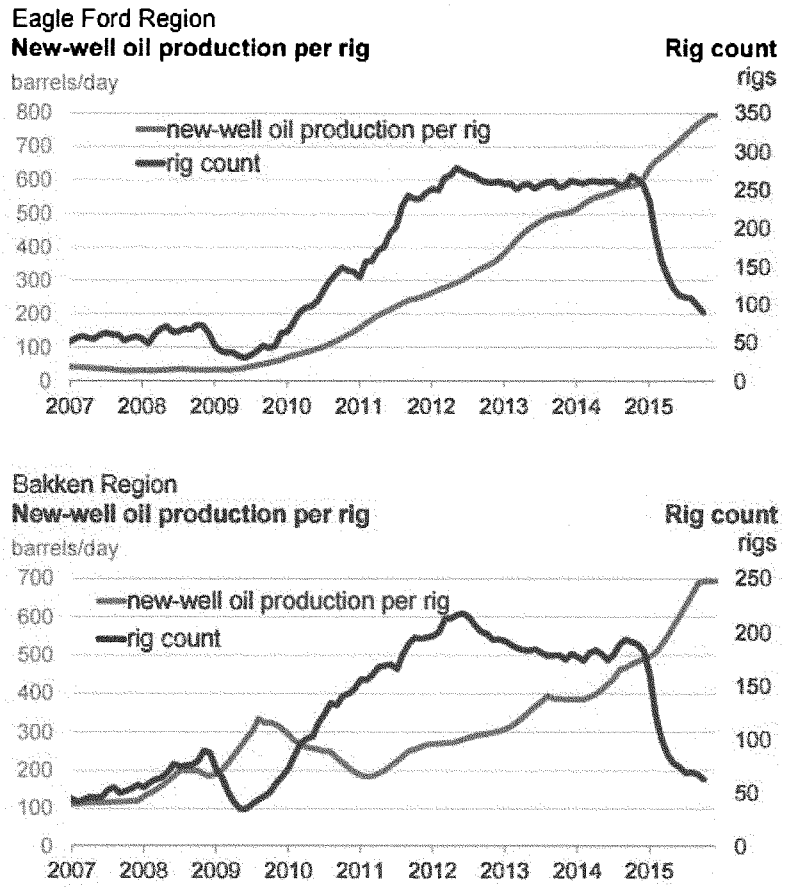
[11] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector. EPA-452/R-15-002 (Aug. 2015) at 3-9.

[12] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015). Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.



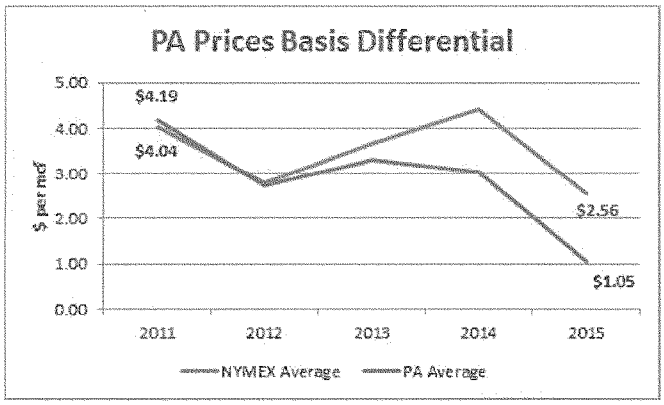
SOURCE: U.S. Energy Information Administration

EPA's cost-effectiveness analysis of the proposed regulations "applies the monetary value of the saved natural gas as an offset to the" cost of the proposed controls.[13] EPA then valued 1,000 standard cubic feet (Mcf) of natural gas at $4.00 for the RIA/cost-effectiveness analysis. The $4/Mcf assumption was based on EIA's 2014 Annual Energy Outlook forecasted

[13] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,617(Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

wellhead prices for the lower 48 states in 2020 ($4.46) and in 2025 ($5.06). EPA considered the $4/Mcf to be "conservative"[14] – presumably because of the predicted value of natural gas in 2020 and 2025. There are numerous problems with EPA assumptions. First, the New York Mercantile Exchange (NYMEX) settlement price for natural gas in October 2015 was $2.56 – 36% lower than EPA's assumed value. EPA has repeatedly indicated that it will finalize the proposed methane NSPS by the summer of 2016, and no financial institution is predicting a dramatic increase in natural gas prices between now and then. For those subject to regulations that come into effect within the next year, EPA's "conservative" estimate of $4/Mcf based on government estimates of what natural gas will cost in 2020 and 2025 is meaningless. IPAA/AXPC appreciates that the "benefit" or value of the natural gas saved by the proposed regulations occurs over the life of the well; however, the emissions from any well are heavily "front-loaded" – with the greatest production, and thus potential emissions, occurring the first few years of the well's life – long before 2020 or 2025. Smaller independents, many conventional well operators, and operators of wells that are marginally economical will not be able to weather the storm until natural gas reaches EPA's conservative value of $4/Mcf. Wells will not be drilled or will be shut in prematurely, and other companies will simply go out of business because of EPA's erroneous assumption on the price of natural gas. EPA's cost-effectiveness analysis for all proposed controls should be based on a price of natural gas that: a) more accurately reflects the price of natural gas when controls will need to be implemented, and b) accounts for the "front loading" of emissions when the price of natural gas is much lower than the $4/Mcf assumed by EPA.

EPA's assumption of $4/Mcf natural gas also fails to acknowledge or account for significant regional differences in the price of natural gas. A review of the wellhead price of natural gas in Pennsylvania provides but one of the many dramatic price variations.



[14] *Id.*

The chart above tracks the PA Price versus NYMEX average prices for the past 4 years and is current through October 2015. The "PA Price" is based on a weighted average of the Dominion South, Leidy, and Tennessee Zone 4 prices reported by Platt's *Inside FERC*. The separation of prices in Pennsylvania from the national index price is driven in large part by the lack of takeaway pipeline capacity and sheer volume of natural gas. The regional variation in price is not accounted for in EPA's cost-effectiveness analysis. Consequently EPA's inflated valuation of the price of natural gas will disproportionally impact certain regions of the country where local or regional factors result in prices that are significantly lower than the national average. EPA's cost-effectiveness analysis must take such significant regional price fluctuations into consideration when evaluating control options.

EPA is proposing regulations so fast that even it cannot keep up with the changing assumptions. Part of EPA's assumption of $4/Mcf natural gas was based on EPA's proposed Clean Power Plan.[15] However, EPA's final Clean Power Plan changed its "assumptions," and EPA now "believes" renewables will play a greater role in the country's future energy mix and natural gas prices may not reach $4/Mcf until after 2030 – well beyond the EPA's analysis for the proposed methane NSPS which ends in 2025. As Energy In Depth points out, the changing assumptions have a dramatic impact on the industry:

> According to EPA data compiled by the American Wind Energy Association (AWEA), a heavier reliance on renewables could result in natural gas prices that are at least 12 percent lower than what would be expected under EPA's base case projection [for the Clean Power Plan]. EPA also acknowledges in its RIA that a $1/Mcf change in price of natural gas translates to as much as a $19 million difference in its cost estimate. In other words, if natural gas prices averaged $3/Mcf instead of $4/Mcf, EPA could be overestimating revenue by roughly 24 percent. Based on the current 2012-2015 average natural gas spot price of $3.44/Mcf, EPA would be overestimating revenue by about $10.6 million. Under the "high renewables" scenario in the Clean Power Plan, which would depress natural gas prices even further, EPA's overestimate would be even higher.
>
> The additional costs could be devastating for an industry already suffering from a market downturn in commodity prices. An analysis by Oppenheimer & Co., for example, already found that EPA's methane rule could wipe out smaller drillers across the United States.[16]

In addition to failing to account for the changed assumptions for the price of oil and natural gas as a result of the Clean Power Plan, EPA has made no effort to account for the impact associated with proposed Ozone NAAQS. For EPA to evaluate the proposed impact of the proposed methane NSPS in a vacuum, ignoring its own significant regulatory initiatives that will have serious impacts on the price of oil and natural gas, as well as the number of entities that will be

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[15] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth. *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.

[16] *Id.*

subject to controls, is arbitrary and capricious. Every mutual fund and investment opportunity contains the standard disclaimer along the lines of – "past performance cannot guarantee future results." The oil and natural gas industry is no different – even without EPA impacting market forces with multiple regulatory disruptions.

III. Now is Not the Time to Introduce a New Model to Justify EPA's Proposed Rules.

The benefits of the proposed rule are estimated using the social cost of methane ($SC\text{-}CH_4$), which has been derived from the approach the United States Government (USG) uses for estimating the social cost of carbon (SCC). However, unlike the USG's SCC which has undergone formal public comment and review, EPA's selected value for $SC\text{-}CH_4$ in this proposed rulemaking is arbitrarily taken from one scientific report[17] that attempts to find an equivalent $SC\text{-}CH_4$ from the SCC, and for which EPA only requested a "peer review" not formal public review and comment. The "peer review" was only concluded in 2014 and discussed as the basis for EPA's cost-effectiveness analysis for the first time in the RIA.[18] The model has not been evaluated by Office of Management and Budget. Providing industry a mere 60 days (plus 17) to evaluate and comment on what amounts to "new math" is inadequate. Also, the selected value of $SC\text{-}CH_4$ used for the Benefit-Cost Analysis in the RIA is based on an arbitrarily selected discount rate of 3 percent, which also was not proposed for public review and comment before being used to justify this proposed rulemaking.[19] Even though now EPA belatedly "seeks comments on the use of these directly modeled estimates, from the peer reviewed literature, for the social cost of non-CO_2 GHGs . . .,"[20] such a request, after EPA has already used its arbitrary value for $SC\text{-}CH_4$ to justify methane emissions controls on numerous methane emissions sources, is arbitrary and capricious. The only proper and legal way for EPA to apply a $SC\text{-}CH_4$ value to methane emissions reductions for proposed rulemakings is to publish a proposal for a $SC\text{-}CH_4$ value (based on scientific evidence and its arguments for a certain discount rate), take public comments on that proposed value, and finalize the value for future rulemakings. Otherwise, EPA can arbitrarily use one value of $SC\text{-}CH_4$ to justify controls on methane emissions from one industrial sector source and then turn-around later and use some other arbitrary value for another industrial sector source, all presumably justified by taking comment on the arbitrary value already used to justify the proposed regulations.

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[17] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,655 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[18] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 (Aug. 2015).

[19] Exacerbating the arbitrary nature of the 3% discount rate for benefits, EPA inconsistently and inappropriately selected a 7% discount rate for the cost to industry. EPA's unjustified use of different discount rates arbitrarily and capriciously overstates the benefits compared to the costs.

[20] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,656 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

IV. Overarching Comments Particular to the Proposed NSPS for Methane, Subpart OOOOa.

In Sections V and VI of the preamble to the proposed NSPS, EPA dedicates considerable verbiage attempting to justify the need and its legal authority to regulate methane from sources in the oil and natural gas sector. IPAA/AXPC disagrees with both the need and EPA's authority to regulate methane for the reasons set forth below.

EPA's interest in regulating methane is clearly a political decision rather than an environmentally driven decision. Its genesis can be easily seen in the strident demands from anti-fossil energy groups with agendas not to manage industrial emissions but to prevent the development of oil and natural gas. Groups like the Sierra Club have policies that are clear:

> There are no "clean" fossil fuels. The Sierra Club is committed to eliminating the use of fossil fuels, including coal, natural gas and oil, as soon as possible . . . Methane released via extraction and transport is 86 times more potent as a greenhouse gas than CO_2 over a 20-year time frame. The climate-disruption impacts from methane and carbon dioxide emitted by extraction, transport and burning clearly point to the urgent need of keeping fossil fuels in the ground.[21]

This group, along with others, made their demands known to the EPA in multiple meetings and letters, including a December 2013 letter stating the following:

> We commend EPA for updating its VOCs performance standards for this industry in 2012, but the job is far from finished. While some reductions in methane emissions will be achieved as a co-benefit of these 2012 rules, many emission sources are not adequately addressed, such as the vast network of equipment that was installed before those rules went into effect. EPA needs to take immediate steps to produce regulations to directly reduce methane pollution from new and existing equipment from this industry.[22]

Once demanded, the issue of direct methane regulation became the pivot point for development of the current regulatory proposals. As discussed below, the drive for direct methane regulations for the oil and natural gas sector is driven by atmospherics and philosophy, not science or increased environmental benefit.

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[21] *Sierra Club to Big Oil: There are no 'clean' fossil fuels.* Sierra Club (Apr. 21, 2015) *available at* http://angeles.sierraclub.org/news/blog/2015/04/sierra_club_big_oil_there_are_no_clean_fossil_fuels.

[22] Earthworks, *et al.* Interior Secretary Jewell, EPA Administrator McCarty to Curb Methane Emissions from Oil and Gas Industry. Earthworks (Dec. 5, 2013) *available at* https://www.earthworksaction.org/library/detail/open_letter_to_interior_secretary_jewell_epa_administrator_mccarthy_to_curb#.VmHY97Eo74Y.

In reality, EPA was forced to propose regulations to satisfy a political agenda that is governed more by what "we [EPA] believe that the industry can bear . . . and survive."[23] EPA's decision to promulgate methane standards from the exploration and production segment of the oil and natural gas sector is arbitrary and capricious. EPA states that it "believe[s] it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category . . . ."[24] Yet in the very same sentence EPA admits "that the best system of emission reductions (BSER) for methane for all these sources is the same as the BSER for VOC."[25] EPA continues that the BSER for the previously unregulated sources is the same for VOCs and methane. Simply put, the controls on the targeted emissions sources to reduce VOCs are the same as the controls to reduce methane – no more, no less. The "gain" – according to EPA – of adding yet another Subpart of regulations to the already extensive 40 C.F.R Part 60 is "consistency." What EPA chooses to ignore in its preamble discussion is the inevitable "loss" or cost to the industry associated with the regulation of existing sources under Section 111(d).

EPA is silent as to its "beliefs" on whether the industry can "survive" the cost and burden of regulation of existing sources under Section 111(d). This silence is notable and troubling. Clearly, since EPA demonstrates that the technologies used to regulate methane emissions are identical to those for VOC emissions, EPA's choice to expand its regulations to directly regulate methane can only be interpreted as opening a potential pathway to Section 111(d) regulations as the anti-fossil energy organizations demanded. And, while EPA fails to even mention Section 111(d), it must certainly know – based on the demand that existing methane sources must be regulated – that it will face efforts to force such regulation. EPA will surely respond that it will conduct the necessary cost-benefit analysis when it is "forced" to promulgate existing source standards under Section 111(d). Without debating the legalities as to EPA's duties under Section 111(d), this Administration has demonstrated time and time again its propensity to feign resistance to non-governmental organizations' (NGO) "demands" and enter into consent decrees with unreasonable short time periods to promulgate regulations. The irony is that EPA's rationale assumes that the underlying Section 111(b) regulations were necessary in the first place. What has the environment gained (above the benefits gained from VOCs) from regulating methane emissions from exploration and production directly? Nothing. EPA has admitted it. The controls are the same – equally efficient at controlling VOCs and methane. The cost? EPA relies heavily on its original cost-effectiveness analysis for the Subpart OOOO VOC regulations finalized in 2012 and engages in additional analysis discussed in Section VIII of the preamble, concluding that the proposed controls "for methane" are also cost-effective. But nowhere does EPA take into account the cost to the industry associated with the regulations that will likely be forced upon existing sources in this source category. Despite all of the complicated calculations and analyses, the simple fact remains that the controls for VOCs and methane from the targeted sources are the same. There is no demonstrated "need" or unique benefit associated with an additional set of standards specifically for methane. The true cost of the proposed methane

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[23] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

[24] *Id.* at 56,595.

[25] *Id.*

regulations is incomplete and unknown without considering the cost associated with regulating existing sources under Section 111(d).

"Consistency across the category" is an insufficient justification. Historically, EPA has tailored new source performance standards to subcategories or segments within a larger, overarching category. One needs to look no farther than Subpart D and its progeny for Steam Generating Units or Subpart E for Municipal Waste Combustors. EPA has shown it can be very creative in tailoring requirements to subcategories or segments within a listed category. Since the Administration first hinted at regulating methane directly from the exploration and production segment, IPAA/AXPC has advocated that such direct regulation was unnecessary, as the controls for VOCs were exactly the same as for methane. EPA acknowledged as much in Section VII in the preamble and stated "[w]e anticipate that these stakeholders will express their views during the comment period."[26] IPAA/AXPC questions the appropriateness of EPA's decision to essentially ignore a central premise of two federal trade associations that represent approximately 54% of oil and 85% of natural gas exploration and production capacity of this country. Is it appropriate for IPAA/AXPC to guess as to EPA's reasoning and justification? Much of EPA's 67-page preamble is dedicated to justifying its legal basis for regulating methane directly and the cost-effectiveness of the proposed controls. It fails to address in any meaningful way why it is necessary or justified to promulgate methane standards from the exploration and production segment. EPA's justification boils down to: 1) EPA assumes it is has the legal authority to do so; 2) EPA has placed a high value on "consistency" within the source category; and 3) EPA "believes" the industry can "survive." EPA is on much stronger legal footing addressing segments or subcategories differently within the oil and natural gas sector than asserting it does not need a separate endangerment finding for methane. EPA's insistence, without explanation, on promulgating methane standards for exploration and production sources, when the controls are exactly the same, needlessly increases the regulatory burden on everyone – the regulated and the regulator. IPAA/AXPC should not have to guess until the rule is finalized and potentially litigate an issue that has been clearly articulated to EPA, the Small Business Administration, and the Office of Management and Budget long before the rule was even proposed.

In Section V and VI, EPA indicates it is responding to and granting a Petition for Reconsideration associated with the 2012 NSPS Subpart OOOO for VOCs which requested the promulgation of NSPS for methane. The key elements outlined as EPA's reasoning for granting reconsideration are:

- "the wealth of additional information now available to us . . ."[27]
- "[t]he oil and natural gas industry is one of the largest emitters of methane, a GHG with a global warming potential more than 25 times greater than that of carbon dioxide."[28]

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[26] *Id.* at 56,609.

[27] *Id.* at 56,599.

[28] *Id.*

- "because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to oil and natural gas source category in order to establish standards of performance for the methane from those sources."[29]
- "a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare for current and future generations."[30]

EPA then dedicates approximately 10 pages of the preamble to defending their position that a separate endangerment finding strictly for methane is not needed (and backfilling in case they are wrong), making the case for global climate change from GHGs, and presenting various charts on U.S. methane emissions. Unlike the remaining sections of the preamble (approximately 55 pages), in which EPA seeks specific comments on particular issues at least 50 different times, EPA did not seek comment once in Sections V and VI.

While IPAA/AXPC has not attempted to take issue with or refute every inaccuracy or assertion contained within these sections of the preamble, EPA's key elements are addressed briefly below:

- IPAA/AXPC agrees there is a wealth of additional information – much of it taking issue with anthropogenic global warming. A cursory review of the website Watts Up With That, http://wattsupwiththat.com/, reveals the science is not "settled" as EPA would have one believe.
- While EPA alleges that the oil and natural gas sector is one of the "largest emitters of methane", EPA's own numbers illustrate that in 2013, the oil and natural gas sector accounted for 2.22% of the Total U.S. GHG Inventory.[31] And as stated earlier, the exploration and production segment is only 1.07% of that 2.22%. The oft-quoted greenhouse gas multiplier is subject to manipulation based on the timeframe used to make the carbon dioxide comparison, and the "legacy warming from fugitive methane is minuscule compared to that of carbon dioxide."[32]
- The adequacy of EPA's endangerment finding is far from settled and will certainly be subject to legal challenge upon final promulgation of this rule if EPA persists with its intention to regulate methane directly.[33]
- In supporting its claim that EPA better understands climate change, it cites the Intergovernmental Panel on Climate Change's (IPCC) 2013-2014 Fifth Assessment Report (AR5). Many of these "citations" or statements to support EPA's position are

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[29] *Id.* at 56.601.

[30] *Id.* at 56602.

[31] *Id.* at 56.608.

[32] Elizabeth A. Muller and Richard A. Muller, *The Facts About Fugitive Methane*, Centre for Policy Studies (Oct. 2015) *available at* http://www.cps.org.uk/files/reports/original/151022155129-TheFactsofFugitiveMethane.pdf.

[33] David Yaussy and Elizabeth Turgeon. *Unringing the Bell: Time for EPA to Reconsider Its Greenhouse Gas Endangerment Finding*, 116 W.Va. L. Rev. 1007 (2014).

from the Summary for Policy Makers, which was written by the policy makers, not the scientists who authored the report.[34] Judith Curry, former Chair of the School of Earth and Atmospheric Sciences at the Georgia Institute of Technology, evaluated and commented on the AR5, not the Summary for Policy Makers, and noted various factors that evidence a weakening of the case for anthropogenic global warming:

- Lack of warming since 1998 and growing discrepancies with climate model projections
- Evidence of decreased climate sensitivity to increases in CO_2
- Evidence that sea level rise from 1920-1950 is of the same magnitude in 1993-2012
- Increasing Antarctic sea ice extent
- Low confidence in attributing extreme weather events to anthropogenic global warming.[35]

- EPA also relies heavily on the U.S. Global Change Research Program's (USGCRP) 2014 National Climate Assessment, Climate Change Impacts in the United States (NCA3), to support its alleged climate change impacts – ranging from decreased Artic summer sea ice to increased sea levels to drier/more intense storms, as well as greater impact to children and the elderly.
  - Studies not cited by EPA demonstrate no significant changes or deviations from cyclical patterns in the quantity of ice.[36]
  - As to the frequency and intensity of storms, other studies not cited by EPA raise questions regarding storm predictability: "October marks a continuation of a record-long major hurricane (Category 3 or stronger) landfall drought in the United States. The last major hurricane to make landfall in the U.S. was Wilma on October 24, 2005. This major hurricane drought surpassed the length of the eight-years from 1861-1868 when no major hurricane struck the United States' coast. On average, a major hurricane makes landfall in the U.S. about once every three years. The reliable record of landfalling hurricanes in the U.S. dates back to 1851."[37] "The bar [see footnote] charts

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[34] Wim Rost, *IPCC ≠ Science ↔ IPCC = Government*, Watts Up With That (Nov. 29, 2015) *available at* http://wattsupwiththat.com/2015/11/29/ipcc-science-ipcc-government/.

[35] Judith Curry, *IPCC AR5 Weakens the Case for AGW*, Climate Etc. (Jan 6, 2014) *available at* http://judithcurry.com/2014/01/06/ipcc-ar5-weakens-the-case-for-agw/.

[36] http://ocean.dmi.dk/arctic/plots/icecover/icecover_current_new.png; http://nsidc.org/data/seaice_index/images/daily_images/S_stddev_timeseries.png

[37] National Oceanic and Atmospheric Administration , National Centers for Environmental Information. State of the Climate: Hurricanes and Tropical Storms for October 2015 (Nov. 2015) *available at* https://www.ncdc.noaa.gov/sotc/tropical-cyclones/201510. While other ranking metrics for hurricane's are being developed, the National Hurricane Center for the National Oceanic and Atmospheric Administration and EPA continue to regularly rely on an cite to the Saffir-Simpson Hurricane Wind Scale to compare the potential impacts of hurricanes.

> below indicate there has been little trend in the frequency of the stronger tornadoes over the past 55 years."[38]

The title of Section V of the preamble is "Why is the EPA Proposing to Establish Methane Standards in the Oil and Natural Gas NSPS?" EPA's stated concerns are ostensibly laudable. However, nothing set forth in Section V or Section VI of the preamble justifies or necessitates separate methane NSPS from the exploration and production sector.

A. Consistent with the Clean Air Act, State Programs Should Control

The CAA is structured such that states should have primacy and be primarily responsible for compliance with the requirements of the Act. Many of the states with the most active shale plays have implemented state regulations to address many of the emissions sources targeted in the proposed Subpart OOOOa regulations. States with state permitting programs and/or State Implementation Plans (SIPs) that contain limits on sources that are legally and practically enforceable should be deemed sufficient for overlapping and duplicative requirements in Subpart OOOO and the finalized version of Subpart OOOOa. EPA should defer to existing state regulations to the greatest extent possible to deem compliance with state regulations on the same sources as constituting compliance with the final Subpart OOOOa regulations. Duplication and inconsistency between state and federal regulations simply add to the cost of compliance with little to no additional benefit to the environment. To the extent EPA does not allow for such provisions, EPA should demonstrate that the duplicate or "more stringent" regulations that EPA is promulgating are incrementally cost-effective: meaning that the cost associated with the duplicative or inconsistent federal control requirement is cost-effective based on the incremental environmental benefit above the state regulation already in place or deem compliance with the state regulations as compliance with Subpart OOOOa. EPA must justify with an *incremental* cost and benefit analysis any proposal to impose additional federal regulations that it deems more stringent than existing state regulations.

B. Fugitive Emissions at Well Sites and Compressor Stations

Managing fugitive emissions or "leaks" from the oil and natural gas sector appeals to common sense. Leaks associated with natural gas operations represent safety concerns, negative impacts to the environment, and are wasteful from an economic standpoint. The industry has relied on audio/visual/olfactory (AVO) inspections for many years, and only recently has the industry focused considerable attention on technological advances to detect leaks. It is an emerging process – both in terms of technology and methodology (regulatory and corporate management). EPA's preamble bears this fact out with the number of specific requests for "comment" on the leak detection aspect of the proposal. IPAA/AXPC supports, in concept, the ability to satisfy the leak detection and repair (LDAR) requirements of the proposal with an appropriate "corporate fugitive monitoring plan," but a 60-day comment period (plus a random 17 days halfway through the comment period) is not enough time to create and implement such a

[38] National Oceanic and Atmospheric Administration, National Centers for Environmental Information, Historical Records and Trends, *available at* https://www.ncdc.noaa.gov/climate-information/extreme-events/us-tornado-climatology/trends.

program. Additionally, recent data and studies demonstrate that production fugitive emissions are characterized by a few sources ("fat tails") representing the overwhelming majority of emissions.[39]

A handful of states are taking the lead on creating regulatory frameworks, each of which is different, and none of which follows the proposed EPA framework. Experience with the state programs is indicating that correction of fat tail emissions results in effective management of fugitive sources and, once corrected, the need for full-blown inspections/surveys more often than an annual frequency is unjustified. Even the states with the most aggressive LDAR programs are not focused on quantifying the total amount of methane "saved." The very nature of fugitive emissions makes it very difficult to quantify how much gas is being "saved." It is not as simple as a single point source with consistent flow where one can easily measure the emissions before and after controls are "bolted on" a stack or emission point. The component count at most facilities is likely in the hundreds to thousands, with only a very small percentage of the components leaking. For those that are leaking, the quantity of gas leaking varies considerably. Nonetheless, EPA crunched some numbers in a hypothetical world and assigned some value to the natural gas that is saved. In reality, very few companies will realize any change in the sales meter pre- and post-LDAR. The savings are largely illusionary to the average operator. The value of the natural gas "saved" through the LDAR programs is highly speculative. In addition, EPA did not account for the size of the facility when estimating the percent savings. EPA's percentage saved calculations are based on Colorado's regulations and related data. Colorado's 80% reduction, which EPA adopts, is based on monthly inspections for facilities with less than 50 tons per year. EPA assumes, with no additional support, that their proposed regulations can achieve an 80% reduction from quarterly inspections for all facilities, regardless of size. IPAA/AXPC questions the validity of EPA's cost-effectiveness analysis for its proposed LDAR regulations.

EPA should withdraw the proposed LDAR NSPS because it has not been developed based on the emerging experiences with fugitive emissions management programs, it locks in a technology approach that may be cost ineffective as experience with state programs evolves, and it would stifle the development of better approaches. Instead, EPA should work with states to learn from their programs and provide for a flexible voluntary fugitive emissions program in the Methane Challenge that would build a basis for a cost-effective NSPS in the future, if one is needed. At a minimum, implementation of any program should be delayed and EPA should work with industry to establish the necessary elements of a corporate fugitive monitoring plan that companies could adopt and customize to meet their particular needs while satisfying EPA's LDAR requirements. This performance-based approach would be the most effective and efficient.

Other than the handful of companies that provide the optical gas imaging (OGI) technology, industry is united in its position that EPA should not select or dictate the technology for detecting leaks. The concept behind NSPS is setting a performance standard that must be

[39] David T. Allen, *et al.* Measurements of methane emissions at natural gas production sites in the United States, Proceedings of the National Academy of Sciences of the United States of America (Aug. 19, 2013) *available at* http://www.pnas.org/content/110/44/17768.

met – not dictating a particular technology. Dictating a particular technology stifles innovation. There are approximately a half dozen or more additional technologies/techniques that are being marketed and/or developed including, but not limited to: tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser-based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas lead detectors; and remote methane leak detectors. These are in addition to the existing Method 21 procedure that some companies find workable and preferable. The need and motivation to "build a better mouse trap" will cease to exist if EPA dictates the technology, and there is no reason for EPA to select one technology.

OGI/forward looking infrared (FLIR) technology suffers from numerous limitations. Perhaps most importantly, it is not inherently safe – if not used properly on site, it could cause an explosion. Additionally, the results of the camera, the "pictures", are difficult to interpret and subject to misinterpretation, e.g., what appears to be a leak could simply be a heat plume. These problems are exacerbated in windy and/or cold conditions that are prevalent in a number of the shale plays. The technology is prohibitively expensive to smaller operators, and there is a limited supply of qualified service providers that can afford the camera. Even for the larger companies, at approximately $120,000 a camera, there will be a limited supply. For companies with diverse geographic locations, it will be difficult to comply with the short survey timeframes set forth in the proposal. The proposed regulations also require survey pictures to contain GPS coordinates. Some of the cameras do not have that function, thus requiring another device to comply with the regulations. Finally, the OGI technology is not a quantitative tool – it is not capable of determining how much natural gas is leaking.

As discussed above, a number of states are taking the lead on LDAR programs and are learning how to effectively and efficiently implement controls and administer surveys. Despite repeated requests by IPAA during the Small Business Advocacy Review Panel process and other trade association requests for EPA's proposal to be consistent with and not duplicative of existing state LDAR programs, EPA's proposal runs roughshod over existing state programs. Inconsistencies and duplication in the proposed regulations and existing programs are burdensome, inefficient and costly – especially to small entities and independent operators. IPAA/AXPC specifically incorporates by reference the comments on the NSPS proposal of Anadarko which highlight the inconsistencies between the proposed Subpart OOOOa and existing regulations in Colorado and Pennsylvania. EPA's proposed regulations essentially punish states and operators within those states that proactively moved to address fugitive admissions. Such an approach does not make for sound policy. States with existing programs should be deemed sufficient, and compliance with the state program should be deemed as compliance with the finalized federal program. This is not a new concept in the context of EPA's NSPS for the oil and natural gas industry, and EPA should revise the proposed regulations to model the exemption for storage vessels in Subpart OOOO and deem legally and practically enforceable state LDAR programs to suffice for the proposed federal regulations. Such revisions would greatly reduce the regulatory burden for sources located in states that have proactively addressed fugitive emissions from the oil and gas sector. To the extent a party (whether EPA or a third party) believes an existing state program is inadequate, the burden should be placed on the entity making the allegation, and EPA should establish a process to address the complaint.

Additionally, consistent with the CAA, the state programs should control, and EPA should implement procedures in the final regulations for states to submit for approval a state-based LDAR program that is deemed sufficient to satisfy EPA's final LDAR requirements.

Another issue advocated by IPAA/AXPC and/or member companies prior to publication of the proposed rule was to *not* base LDAR requirements on arbitrary component count or percentage of components leaking at a given site – yet that is exactly what EPA proposed. EPA suggests that its proposal, which bases the frequency of surveys on the percentage of leaking components, provides an "incentive" for companies to be more vigilant in their identification and repair of leaks. As discussed above, the incentive to identify and repair leaks already exists, as there is a strong safety and economic incentive. EPA's proposal based on percentage of leaking components creates a recordkeeping nightmare. The regulations are less than clear as to what constitutes a "facility" in terms of where to draw the line and stop the component count. As a result of the ambiguity in the proposal, it is difficult to evaluate if EPA's assumptions on components per well count are accurate. There is tremendous variability in the number of wells and types of equipment on well sites. For EPA to base its cost effectiveness on a "model well pad" is problematic. Member companies report component counts in the hundreds to thousands of components. Such a wide range is in part, a function of lack of clarity in the regulations and also calls into question the accuracy of EPA cost-effectiveness assumptions on a model plant. If EPA persists with a percent-leaking methodology, the regulations need to be clarified on what components are to be counted and how to define the limits of the facility for the component count. EPA's own evaluation concluded that quarterly surveys of the intensity proposed are not cost-effective. Yet, if more than 3% of the components are leaking, the proposed regulations require quarterly surveys. If quarterly surveys are not cost-effective, having more than 3% of the components leaking does not somehow make the quarterly surveys become cost-effective. Additionally, there is no direct correlation between the number of leaking components and quantity of emissions, so basing the frequency on the percentage of leaking components does not necessarily mean the program will be more effective at preventing fugitive emissions. While there is no direct correlation between the number of components and quantity of emissions, the component count/percent leaking ratio directly impacts the recording keeping requirements – again with no demonstrated reduction in emissions. It is just more paperwork compliance for operators.

Furthermore, leaks are often related to some sort of malfunction and once fixed, stay fixed such that there is no need or rational basis to increase the survey frequency. As EPA discussed in the preamble, experience with the state programs demonstrates there are "gross emitters" or "super emitters" that represent a very large percentage of the overall fugitive emissions profile (consistent with the fat tail issues discussed above). Preliminary information from companies with operations in states with aggressive LDAR programs already in place indicates treating every component "equally" is an inefficient use of limited resources. This information suggests that components subjected to constant or frequent vibration (such as components associated with a compressor) are much more likely to have leaks than say, threaded connections. And in terms of total component count at a given facility, there are likely to be many more threaded connections than the components most likely to leak at the relatively few compressors. Even if it is difficult to predict "gross emitters" or "super emitters" at any given

facility, the knowledge gained from sources within states with existing LDAR programs suggests that treating all components equally and basing the frequency of surveys on leaking component percentages is inefficient from an emissions reduction perspective and extremely burdensome and costly – especially to small entities. Again, more time to craft a regulatory program designed to identify and repair gross emitters would be preferred by IPAA/AXPC.

Basing the frequency of surveys on the percent of components leaking exemplifies that EPA is largely guessing at what constitutes an appropriate LDAR program. EPA should not rush to judgment and instead learn from the state programs to determine the most effective and efficient way to reduce leaks. Alternatives include a performance-based approach such as that in Wyoming, basing the survey frequency on the size of the facility or the quantity of emissions leaked or perhaps a combination of a more technology-based annual survey with periodic AVO "inspections" between annual surveys. If EPA persists with the percentage-leaking-component approach, flexibility should be built into the program that companies could commit to semi-annual surveys and not be subject to fluctuation from quarterly to annual surveys based on the number of components leaking. For some companies, the ability to plan for semi-annual reporting without the risk of quarterly monitoring would be more beneficial than the changing requirements and potential cost saving of annual surveying. However, for some smaller entities or independent operators, the ability to reduce surveys to an annual basis might be beneficial. Sources should be given the flexibility to choose. Flexibility in complying with the LDAR program will help reduce the cost and burden.

Individual components that are to be included for "fugitive" emissions monitoring must be better defined and differentiated from components that are designed to emit a certain amount of natural gas under certain circumstances. Further, components of the storage vessels, e.g., closed cover/vent/control systems, already covered under Subpart OOOO for storage vessels should not be subject to additional requirements. As some states have done, EPA should more clearly define and exclude components that are designed to release pressure for safety reasons, e.g., thief hatches and enardo valves.

Dictating a particular technology (OGI/FLIR) and then requiring the initial survey be conducted within 30 days (and repaired within 15 days) is an unreasonably tight time period – especially for smaller entities and operations with disperse and remote locations. These timeframes should be extended to 60 and 30 days, respectively. If EPA persists with the unrealistic time frames, a mechanism allowing for a "variance" on the time frames when certain circumstances exist should be built into the regulations. Even with companies with the resources to purchase a camera, their operations may be geographically dispersed or weather conditions are uncooperative such that they cannot realistically get from one location to the other. Smaller entities and some independent operators who cannot afford the dictated technology are then at the mercy of the market to comply within 30 days. Especially during the early implementation of the new rules, many sources are likely to incur enforcement/liability through no fault of their own due to an inability to purchase the technology or hire service providers with the necessary capabilities.

EPA's cost-effectiveness for the proposed LDAR program requirements is fundamentally flawed because it merely looks at the cost of conducting the survey and fails to accurately

account for the increased record-keeping and reporting requirements. EPA's analysis is myopically focused on a straight up comparison of "cost-effectiveness" for semi-annual surveys versus annual and opts for semi-annual requirements because the relative cost-effectiveness is the same: $2,475 for annual versus $2,768 for annual under the single pollutant approach at the well site.[40] EPA conducted similar comparisons for the multi-pollutant approach at the well site (as well as both comparisons at a compressor station).[41] In every instance the annual survey was more cost-effective but EPA selected the semi-annual surveying because the cost/ton removed was similar. There are two problems with that philosophy. First – in selecting the semi-annual requirement, EPA basically double the cost of the requirement to industry. Second, the theoretical or modeled additional reduction in emissions is a very small percentage of the overall emission reductions associated with the proposed regulations. The additional cost associated with the annual survey requirement is substantial while the increased benefit to the environment is minimal. The additional regulatory burden will be disproportionately felt by small entities. The proposed LDAR requirements basically require all companies, regardless of size, to implement costly information systems to track and monitor compliance. For example, one of the larger, more sophisticated operators with a data management system already in place incurred an additional $10,000 in external costs associated with developing new or revised software, and an additional $37,000 associated with internal set-up costs and employee time focused on implementation. These costs were associated with complying with Colorado's LDAR program in a small gas field of 174 wells and, as indicated, were in addition to an existing management system at an estimated cost of $80,000 annually. It does not appear that costs such as these were considered in EPA's cost-effectiveness analysis. EPA's proposed requirements appear to be based on what is required at natural gas plants, and expanding that level of detail to remote, un-manned production sites is inappropriate. Such level of detail is not warranted nor has the cost been adequately justified – especially over the life of the well. The majority of the "benefit" associated with the surveying is on the initial startup of a well (or startup after modifications). It is impossible to calculate an accurate annual gas recovery rate over the life of a well site.

The new record-keeping requirements associated with the LDAR are particularly burdensome to smaller operators with limited staff. For example, the preamble provides limited to no justification for requiring the date-stamped digital photograph. If EPA retains the burdensome record-keeping requirements, companies should be allowed to keep the records on site or at a regional field office and produce them upon request. Companies should not be required to submit electronically or manually to the permitting agency. EPA requested comment on "ways to minimize recordkeeping and reporting burden." As discussed above, EPA should evaluate existing state requirements and liberally deem them sufficient for purposes of Subpart OOOOa and establish a mechanism for states to implement their own programs that supersede and satisfy Subpart OOOOa.

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[40] Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities – Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa (Aug. 2015) (hereinafter, TSD), at Table 5-14.

[41] *Id.* at Tables 5-15, 5-17, 5-18.

IPAA/AXPC supports the limited exclusions from the LDAR requirements that EPA has proposed but requests certain clarifications and expansion of the exclusions. Excluding low production well sites – defined as the "average combined oil and natural gas production for the oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production"[42] -- is extremely helpful for small entities and smaller independent operators. IPAA/AXPC understands the 15 boe is also an "off ramp" – that is, when a well drops below 15 boe, it is no longer subject to the LDAR requirements. IPAA/AXPC requests the regulatory language be revised to indicate that when a well drops below 15 boe, based on a 30-day average production, the LDAR requirements no longer apply. EPA should provide an additional exclusion for well sites with component counts below EPA's model well site: below 548 components for gas well sites and below 135 components for oil well sites should be excluded from the LDAR requirements.[43] EPA concluded that it is not cost effective to implement the proposed LDAR requirements on sites with lower well component counts and therefore those well sites should be excluded. Such exclusion would help all producers but would have greatest benefit to small entities that are likely to have smaller well sites. IPAA/AXPC also supports EPA's proposed exclusion for well sites with extremely dry gas where only the wellhead exists and there is no "ancillary equipment." IPAA/AXPC requests clarification that a meter and drip present at the well site do not constitute "ancillary equipment." Finally, in response to an EPA request for comment, IPAA/AXPC suggests that the LDAR requirements should only apply to those components that are directly connected to the fractured, refractured, or added well and should not apply to tank batteries or other equipment off the well pad which may receive fluids from the fractured, refractured or added well.

C. Oil Well Reduced Emission Completions

As with the proposed LDAR requirements, in its rush to promulgate regulations aimed at additional sources of VOCs and methane, EPA assumed that reduced emission completions (RECs) on oil wells are essentially the "same" as RECs on natural gas wells. Unlike a natural gas well, where the price of natural gas dictates many operational decisions, the economic driver for oil wells is the price and volume of oil – not natural gas. When EPA promulgated Subpart OOOO regulations for VOCs and RECs on natural gas wells, EPA indicated it did not have enough information to determine if oil well RECs were cost-effective.[44] The cost-effectiveness of oil well RECs was also raised by EPA in the Methane "White Papers" released on April 15, 2014.[45] IPAA/AXPC and individual member companies submitted comments on EPA's oil well

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[42] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,612 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[43] TSD at Table 25-1.

[44] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 ,49516 (Aug. 16, 2012)

[45] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production* (Apr. 2014), *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.

REC White Paper - identifying concerns with the cost-effectiveness of RECs for oil wells.[46] EPA's preamble discussion in Section VII of the proposed standards for oil well RECs makes a general reference to the Technical Support Document (TSD) for the current proposal in terms of justifying its best system of emissions reduction determination, but there is no updated cost/benefit data cited in the proposal. The citations refer back to the "2012 NSPS evaluation." It appears EPA has failed to cite any new or additional information collected since the 2012 evaluation to support the cost-effectiveness of the proposed oil well REC requirements. The economics of natural gas RECs are different and do not support oil well REC requirements.

Based on the preamble discussion of undertaking of an oil well REC, EPA assumes the process is essentially the same, but this is not necessarily the case. While certain wells will have relatively clear initial and separation flowback stages like natural gas wells, there are instances where there is no separation flowback stage owing to the lack of gas or quality of gas such that operation of a separator is not feasible. On certain wells, the initial flowback stage is followed by directing the flowback immediately into the production battery. Perhaps more so than with RECs on natural gas wells, the various stages of flowback on oil wells can be difficult to clearly delineate, and the ability to utilize a separator is a function of engineering judgment. IPAA/AXPC supports the concept of identifying two stages of flowback, with no control placed on the associated gas with oil well completions during the initial flowback stage. However, there will be situations where certain oil well completions will not experience a separation flowback stage.

In the preamble discussion of the REC requirements for both subcategory 1 and subcategory 2 wells, EPA expressed a clear intention to allow for venting of emissions in lieu of combustion during periods when the flowback gas is noncombustible.[47] This intent is particularly important for completions utilizing inert gas, such as nitrogen or nitrogen foam, instead of water as the medium for the fracturing process. The inert gases present in the flowback make the gas, for a period of time, "not of salable quality" and technically infeasible. The relevant provisions of the proposed regulations at 40 C.F.R. 60.5375a(a)(3) and 40 C.F.R. 60.5375a(f)(2) should be modified at the end of the provision to allow for venting when "*it is technically infeasible due to inert gas concentration.*" The addition of this phrase at the end of the current proposed language would eliminate any ambiguity as to EPA's intent.

IPAA/AXPC agrees that the feasibility of oil RECs should take into consideration the availability of gathering lines and that it is not as simple as a linear distance from a gathering line. As EPA acknowledges in the preamble, there are many factors that determine gathering line availability – not just distance. There are other considerations that drive the decision to recover gas which include, but are not limited to, the following factors: gas volume, gas pressure, gas Btu content, gas liquid content, sales line gas pressure requirements, moisture

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[46] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

[47] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,630, 56,632 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

requirements, compression, and current takeaway capacity of existing gathering systems. One workable approach that might assist regulators is to use a linear distance, such as a ¼ mile, to presume that flaring is permitted because it is generally agreed that, beyond that distance a gathering line is not available. The converse, a gathering line within a ¼ mile, should not be assumed to be available prompting a case-by-case determination based on the factors detailed above. Again, IPAA/AXPC supports EPA's acknowledgment that the availability of a gathering line must be considered in evaluating the feasibility of an oil well completion but that it is not as simple as designating a linear cut point.

IPAA/AXPC supports the various exclusions from the oil well REC requirements for oil wells less than 15 boe; wells with a gas-to-oil ratio (GOR) of 300 or less; and the low-pressure well. Although not an exact science, operators can make engineering judgments and estimations based on experience in a developed formation. If the well initially exceeds 15 boe, a potential solution is to allow the operator to temporarily shut in the well and bring in REC equipment or limit the production such that the well does not make more than 15 boe for any measurement period as long as the average rate of the averaging period is 15 boe or less. In the event that the operator, based on strong well performance, decides to bring in REC equipment, he could earn a 0 bopd credit to the averaging period for every day the REC is used. IPAA supports the inclusion of an exclusion for a "low-pressure oil well" but it is not appropriate to utilize the definition for a "low-pressure gas well." Oil and water are fairly equivalent on their impact on the intent of this low-well pressure exemption in the early phases of flowback, and the water/oil ratio will change significantly during the early flowback periods for hydraulically fractured wells. The main difference is that, once the hydraulic fracture load stops coming back, a gas well will typically have much less liquids in the production tubing, making the surface pressure actually higher for the gas well vs. an oil well. This difference would be reflected in the 0.038 number which represents the gas gradient in the well, which would impart a back pressure. For oil wells this back pressure would be higher, i.e. more liquids in the tubing, and this factor should be increased. For example a well making 15 boe up 2-3/8" production tubing at a 300 GOR could have a gradient of 5 to 10 times as much. The new record-keeping requirements associated with oil RECs (but also applicable to natural gas RECs) disproportionately impact the smaller, independent operators (conventional operations).

Finally, IPAA/AXPC continues to believe EPA's cost-effectiveness analysis for oil well completions is flawed because it is taking "credit" for well completions industry has already done or will do regardless of regulations. IPAA and WEA filed extensive comments on EPA's oil well completion White Paper on June 16, 2014.[48] The issues raised in that process have not been adequately addressed by EPA in the RIA or Technical Support Document for this rulemaking. The most relevant provisions of those comments are reproduced below:

> Finally, we question the need or benefit of EPA requiring reduced RECs or combustions devices/flares at oil wells as operators are already engaged in such

[48] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014). The Comments of AXPC/America's Natural Gas Alliance (ANGA) are incorporated by reference.

> practices at a majority of the wells. There is a clear economic incentive to capture as much of the gas as possible and where it is not possible to capture the gas, safety concerns for the personnel at the well site drive the installation of flares. It is a matter of economics and common sense—if the gas can be captured economically, it will be. If it cannot be captured economically, and it is present in sufficient quantities to represent a safety concern, it is flared.
>
> See the comments above, as they pertain to EPA's data sources and estimates.
>
> For the reasons set forth above, we have considerable doubt as to the accuracy of the national and per well estimates of methane and volatile organic compounds ("VOC") emissions for hydraulically fractured oil well completions. There is significant variation in the emissions among different well types and wells from different regions. As such, a "national estimate" will not necessarily be representative of wells from a particular region (and, in fact, would be representative only by chance).
>
> . . .
>
> As to factors that influence emissions, there are numerous factors that were not discussed in the White Papers. Most importantly, the White Papers do not adequately address the complex nature of what EPA terms "co-produced" wells, where both oil and gas are produced. Such wells are difficult to classify in terms of how any given well will behave in a wide variety of geologic formations and basins. In addition, EPA does not discuss the well-established fact that nearly all oil wells that produce appreciable amounts of gas are controlled by a combustion device for safety reasons. As mentioned above, the existing economic and safety incentives result in a majority of these wells being "controlled"—whether by a REC or combustion device. In fact, a survey submitted as part of the docket for NSPS Subpart OOOO was conducted by AXPC/ANGA member companies that showed that greater than 90% of wells were controlled prior to the rulemaking. Comment submitted by Amy Farrell, Vice President of Regulatory Affairs, America's Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC); EPA-HQ-OAR-2010-0505-4241. A similar Texas Energy Alliance survey had comparable results, again supporting the position that further EPA requirements mandating REC/flares are not necessary.[49]

In the TSD for the proposed Subpart OOOOa, EPA continues to claim ignorance as to the extent state and local regulations require well completions and claim an arbitrarily low assumption that only 7 percent of completions are controlled in the absence of federal regulations.[50] This

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[49] *Id.* [internal citations omitted]

[50] TSD at 22.

arbitrarily low assumption skews EPA's cost-effectiveness and takes "credit" for activities the industry is doing on its own.

D. Pneumatic Pumps

IPAA/AXPC's primary concern with the proposed requirements for pneumatic pumps is that EPA has overestimated the case (and thus the cost) of sending captured gas to an existing combustion device. It is not as simple as plumbing a line from the pump to the control device. The intermittent nature of the gas flow and low pressures can create serious safety and operational difficulties if not appropriately designed along with significantly increasing engineering costs associated with the closed vent system upgrades. The difference between the amount of gas being vented from a storage tank and the amount of gas coming from a pneumatic pump is large, and designing a closed vent system to properly account for this pressure differential would be exceedingly difficult and costly. To meet the needs of both components, the final design would likely have the potential to increase emissions (such as being forced to use a small compressor or being forced to set thief hatches at different pressures that in turn cause more emission events from the tanks) than if the pump was vented directly to the atmosphere. The volume of gas to be captured from pneumatic pumps is relatively small, and when EPA more accurately reflects the cost associated with capturing the gas and routing it to an existing control device, IPAA/AXPC questions whether the proposed controls will be cost-effective. If EPA persists with its proposed controls on pneumatic pumps, it should clarify the definition of an "affected facility" and the interplay with reporting requirements. "Affected facility" should mean only new or modified continuous high-bleed pumps and specifically exclude low-bleed pumps (< 6 scfh). Since low-bleed pumps would not be considered an "affected facility," it is assumed they would not be subject to the reporting requirements for high-bleed pneumatic pumps. IPAA/AXPC requests confirmation of its reading of the reporting requirements.

The applicability of EPA's proposed regulations turns on whether a control device is already present at the site. EPA's regulations and preamble are silent as to whether the existing control device is already subject to NSPS and therefore an affected facility. To the extent the existing combustion device is not an affected facility, Subpart OOOOa should be clarified that existing, non-affected facility combustion devices should not become subject to NSPS simply because a new pneumatic pump is installed or an existing pump is modified. If EPA intends to pull in the existing control device and make it an affected facility, EPA must revise its cost-effective analysis to account for the additional costs associated with "converting" the existing control device to an affected facility.

E. Compressors

IPAA/AXPC supports EPA's indication that the compressor rules promulgated under Subpart OOOO and proposed Subpart OOOOa do not apply to compressors at the wellsite. IPAA/AXPC interprets the proposed CTG for compressors as essentially the same as that proposed in Subpart OOOOa, yet the CTG indicate the regulations would apply to compressors

"between the wellhead and point of custody transfer."[51] This language seems inconsistent with the concept that compressors at the well site are not subject to Subpart OOOO or the proposed Subpart OOOOa. IPAA/AXPC requests clarification. Similarly, IPAA/AXPC requests clarification on whether compressors at well sites are subject to LDAR requirements. Finally, in response to EPA's specific request, IPAA/AXPC suggests the fugitive emissions requirements at compressor stations should apply only to the fugitive sources that are connected to the added or modified compressor.

F. Liquids Unloading

IPAA/AXPC supports EPA's conclusion that it does not have sufficient information to propose standards for liquids unloading. IPAA and WEA filed extensive comments on EPA's liquids unloading White Paper on June 16, 2014.[52] The numerous issues raised by IPAA/WEA have not been adequately addressed and continue to be the basis for IPAA/AXPC's position that controls aimed at reducing emissions from liquids unloading vary greatly based on numerous factors that make it difficult if not impossible to promulgate a cost-effective NSPS. IPAA/AXPC incorporates by reference these comments in their entirety regardless of topic. Nonetheless, certain portions of IPAA/WEA's comments on liquids unloading warrant repeating:

> The industry has a strong economic incentive to minimize venting episodes. Indeed, what EPA views as a pollutant is generally viewed by industry as a salable product and thus industry has an economic incentive to capture as much of the gas as possible. Unfortunately, it is not always possible to unload without venting—sometimes for safety reasons and sometimes for technological reasons. The limitations on the ability to minimize venting are difficult to predict and largely well-specific.
>
> Although the challenges associated with liquids unloading are equally prevalent among horizontal and vertical wells, the ability to recover the cost of "controls" will most likely disproportionately affect smaller operators, marginal wells and vertical wells. Nowhere in the charge questions or White Paper does EPA attempt to address the potential for such disproportionate economic impacts to result from a "one size fits all" approach to minimizing emissions during liquids unloading. The need to unload liquids depends primarily on reservoir pressure, liquid/gas ratio, and surface operating pressure; the most appropriate technology used to unload will depend on the producing formation, site equipment and logistics, and other considerations. There is a wide variety of reservoir properties across and within basins, and flexibility is critical in the continued production of these wells.

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[51] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

[52] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

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

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

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

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

The need for liquids unloading is not based on a strict set of parameters or rules. It is based on a complex set of variables—primarily reservoir pressure, but

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

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

The cost of the technologies varies and what will constitute a cost-effective technology will vary from well to well. For example with plunger lifts, the capital, installation, and startup cost is an exponential costing issue based on ever increasing depth of the well (e.g., the cost of a 11,000 to 12,000 foot well might approximate $25,000 to $30,000 for certain operations in East Texas whereas a 1000 foot well may only be $2000 or $3000). Also related to plunger lifts, a "smart technology" cost is dependent on many variables such as well density and availability of a communication network. The communication network for 400 densely spaced wells can easily cost approximately $4 million dollars (average of $10,000/well before adding the cost of the smart controls themselves). The EPA's high range of $18,000/well is not necessarily "high" for many situations. As to artificial lifts, the costs are substantially more. One member indicated capital and installation costs for 11,000 -12,000 foot wells are in the range of $150,000 per well -- much higher than EPA's estimates. Again, the depth of the well influences the costs figures and it is difficult and inappropriate to generalize. The best solution to the liquids unloading problem is a case-by-case decision based on the engineering judgment of the operators.

. . .

As noted above, the feasibility of the use of artificial lift systems is generally site-specific and therefore it is difficult to generalize. Artificial lift systems are just one of the available "tools" or technologies to extend the useful life of a well and are utilized where cost-effective. That said, they tend to be cost-prohibitive on deeper low production gas wells and work best on shallow wells

> capable of setting a pump/plunger/gas lift below the bottom perforations. Some characteristics that discourage the use of artificial lift include deep formations, corrosive production fluids, wells with high scaling tendency, and deviated wellbores. The feasibility of artificial lifts must be assessed according to the conditions of the individual well. One size does not fit all.
>
> In certain situations, gas wells with liquid content that are unloaded are capable of being controlled with flares attached to the tank vents at the production battery. In others, the high pressures in certain regions make routing blowdowns to tanks and flares extremely unsafe. Even wells that are blown down can sometimes be vented through tanks that are controlled in many cases by flares. The capability to do this, however, depends greatly on the conditions of the well bore and the equipment used to control (tanks, flares, etc.) These flares and the associated tanks/tank vents are not specifically designed to accommodate liquids unloading. Regarding the use of flares specifically for liquids unloading events, there are several design and operational issues: (1) liquids unloading are slug flow events that are inconsistent in both gas volumes and quality, (2) consequently, designing a flare for the wide range of operating conditions is challenging, (3) additional equipment may be required to prevent liquids from reaching the flare (separators, etc.), and (4) the intermittent nature of these events is another challenging design condition especially in avoiding smoking conditions, etc. To the extent that EPA contemplates a continuous flare to minimize emissions from these intermittent events, the negative externalities associated with the carbon dioxide emissions from the pilot should be factored into any analysis. To accommodate the operational issues associated with flares and associated equipment designed to specifically address liquids unloading, they would need to be relatively large which could present safety hazards and create local permitting issues.[53]

EPA's proposed Subpart OOOOa seems to leave the door open for potential regulation of emissions associated with liquids unloading and requested comment on the issue. IPAA/AXPC supports EPA's decision to not propose federal standards. The issues outlined above have not been adequately addressed by EPA and remain largely unaddressed.

G. Miscellaneous Requests for Input

- EPA requested input on "pressure-assisted flares." IPAA/AXPC is not entirely clear what EPA is referring to as pressure-assisted flares. To the extent IPAA/AXPC understands the type of flare EPA is referring to, IPAA/AXPC does not believe there is any reason to treat these flares differently than any other flare. Or stated slightly differently, pressure-assisted flares should be treated as any other flare subject to the Subpart OOOO and proposed Subpart OOOOa regulations

[53] *Id.*

- IPAA/AXPC supports a clarification that the storage vessel provisions do not apply to large (e.g., 25,000 bbls or more) tanks used for water recycling, as they have very low emissions but might trigger the 6-ton threshold because of size and volume of throughput. EPA's recognition that this water has very low emissions calls into question whether the smaller "storage vessels" that hold the same type of water, just smaller quantities, should be an affected facility.
- IPAA/AXPC does not support EPA's concepts of independent third-party verification, fugitive emissions verification, and "electronic reporting and transparency" as described as part of EPA's Next Generation Compliance and Rule Effectiveness. As an initial matter, companies should be allowed to verify issues internally. EPA's concept of utilizing certified reviewers would pose a significant problem for the industry in terms of not having enough qualified individuals to conduct the review. Eventually the market would adjust, but in the short term there would be a shortage. EPA's concept would create a problem in an attempt to solve an "issue" that currently does not exist. Finally, industry does not support a continuous parametric monitoring system since this would result in significant costs to companies that do not have supervisory control and data acquisition (SCADA) capabilities and would another add link in the system that could fail. A simpler and better solution would be to require all thief hatch vents to be set at a pressure above that of the main ventline.

V. Control Technique Guidelines for Ozone Nonattainment Areas

Clearly, the CAA provides direction to EPA and states that requires the use of RACM in Ozone nonattainment areas to manage emissions from existing sources. However, EPA's presentation of the CTG for oil and natural gas production facilities fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. Moreover, as IPAA/AXPC demonstrated earlier in these comments, the differences between the oil and natural gas production industry and other industry segments requires a recognition that there are significant differences across the industry in the size and scope of operations that dramatically impact the economic implications of controls. The CTG proposals largely ignore this reality. Any CTG for oil and natural gas production facilities needs to provide an application threshold that excludes marginal oil and natural gas wells. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Without the appropriate recognition of the broad diversity of the oil and natural gas production industry and the need for the CTG to be based on appropriate existing source technologies, serious adverse impacts on American production could result. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

Consequently, IPAA/AXPC requests withdrawal of the current CTG proposal until EPA can address its serious shortcomings and determine whether a broad CTG proposal is appropriate as a RACM approach for oil and natural gas production facilities.

Following is a detailed discussion of the basis for IPAA/AXPC's opposition to the current CTG proposal and reasons why it should be withdrawn.

In its Federal Register notice regarding the *Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry*, EPA provides a pertinent description of the RACM process:

> Section 172(c)(1) of the Clean Air Act (CAA) provides that State Implementation Plans (SIPs) for nonattainment areas must include ''reasonably available control measures'', including ''reasonably available control technology'' (RACT), for existing sources of emissions. Section 182(b)(2)(A)of the CAA requires that for Moderate Ozone nonattainment areas, states must revise their SIPs to include RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA section 182(c) through (e) applies this requirement to States with ozone nonattainment areas classified as Serious, Severe and Extreme.
>
> The CAA also imposes the same requirement on States in ozone transport regions (OTR). Specifically, CAA Section 184(b) provides that states in the Ozone Transport Region (OTR) must revise their SIPs to implement RACT with respect to all sources of VOCs in the state covered by a CTG issued before or after November 15, 1990. CAA section 184(a) establishes a single OTR comprised of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.
>
> The EPA defines RACT as ''the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' (44 FR 53761, September 17, 1979).[54]

While this description is accurate, EPA wholly fails to meet the test of identifying "control technology that is reasonably available considering technological and economic feasibility."[55]

To understand EPA's failure, it is essential to expand our earlier discussion of the nature of the oil and natural gas production industry. As described earlier, the oil and natural gas production industry differs from other industries because of the inherent reality that its production is not constant. Instead, because of geological realities, production from most oil and

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

[55] *Id.*

natural gas wells peaks at or near its earliest stages of full production. In essence, once the reservoir is opened, the contained pressure in the reservoir forces oil and natural gas through the well bore to the surface. But, this pressure also begins to diminish and with it the flow rate of the well. While various techniques are available depending on the type of formation to improve production, these actions adjust the rate of decline; they do not return the well to its original productivity.

Consequently, over time, wells move from strong producers to marginal ones. In fact, marginal wells are defined in federal law as oil wells producing 15 barrels/day or less and natural gas wells producing 90 mcfd or less. While these are the thresholds, the average marginal wells produce at much lower levels – the average marginal oil well produces 2.7 barrels/day and the average marginal natural gas well produces 22 mcfd. There are business implications to this production depletion as well. As the operating costs of production increase when production decreases, companies sell less productive wells to obtain capital for reinvestment in new production. Many characterize the oil and natural gas production industry as a "food chain" industry with larger companies selling properties that do not fit their production structure to smaller companies. As a result, marginal well ownership is dominated by smaller organizations, many of which are privately held small businesses. As IPAA/AXPC previously stated, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells.

Correspondingly, as production from wells decreases, the physics of emissions changes as well. With less pressure in the well bore, there is less pressure driving emissions to the atmosphere from operating equipment. Even more telling, the most recent research efforts such as those by the University of Texas' Center for Energy and Environmental Resources demonstrate that emissions at oil and natural gas production operations are dominated by a small percentage of sources. Moreover, experience is indicating that when these sources are corrected and maintained, emissions reductions are sustained for long time periods.

Set against this pattern of industry structure and experience, EPA has failed to create a record that demonstrates it made a thoughtful analysis of the technologies it is proposing in the CTG as RACT – particularly in the context of considering technological and economic feasibility. Instead, EPA has arbitrarily applied the BSER technologies in Subpart OOOO and proposed to do so in Subpart OOOOa as they relate to new sources in the context of existing sources. In doing so, EPA fails to appropriately adjust the economic analysis from the NSPS materials to reflect the different circumstance of existing operations.

Among the key factors that EPA understates is the need to focus these regulations on VOC emissions. Because these CTG address VOC emissions, their cost effectiveness and technological appropriateness must be evaluated with regard to their impact on VOC emissions. For example, EPA bases much of its cost-effectiveness determinations on average VOC emissions, but RACT needs to be considered by each state for each nonattainment area. Different oil and natural gas formations produce different vapor compositions including significantly different fractions of VOCs in the vapor. Correspondingly, for the same cost, cost effectiveness will change; it will become less cost-effective as the VOC concentration diminishes.

Similarly, EPA bases much of its analysis on "model" facilities, but facilities differ depending on the nature of their operations. While EPA's draft CTG proposal recommends that facilities with only a wellhead should not be included in its fugitive emissions CTG, it should similarly recognize that facilities with fewer components than the EPA model facility need to be evaluated based on their actual structure rather than presumed to be cost-effectively controlled under the CTG.

These issues become more compelling when the CTG affect marginal oil and natural gas wells. EPA partly recognizes this reality by stating in the context of its fugitive emissions proposed CTG:

> For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents), and the collection of fugitive emissions components at compressor stations in the production segment. It is our understanding that fugitive emissions at a well site with low production wells are inherently low and that many well sites are owned and operated by small businesses. We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved.[56]

This recognition is entirely appropriate and accurate. However, it needs to apply to all of the CTG. Marginal wells are the most vulnerable U.S. production operations – particularly at the current oil and natural gas commodity prices that are well below the prices used by EPA in its cost-effectiveness analyses. Yet, these wells continue to provide a significant portion of American production. Additionally, the CTG should provide that status as a marginal well qualifies for an off ramp from continuing application of the regulations. That is, when a well's production drops to the point where it is considered a marginal well, the facility would no longer be subject to the regulation.

EPA also needs to recognize that its CTG proposal coincides with its decision to lower the Ozone NAAQS. 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. Since a number of these new projected nonattainment areas encompass production areas, these CTG will have a broader and more significant potential impact on U.S. production. The following map provides a perspective on the interaction between American production areas and nonattainment with the new Ozone NAAQS.

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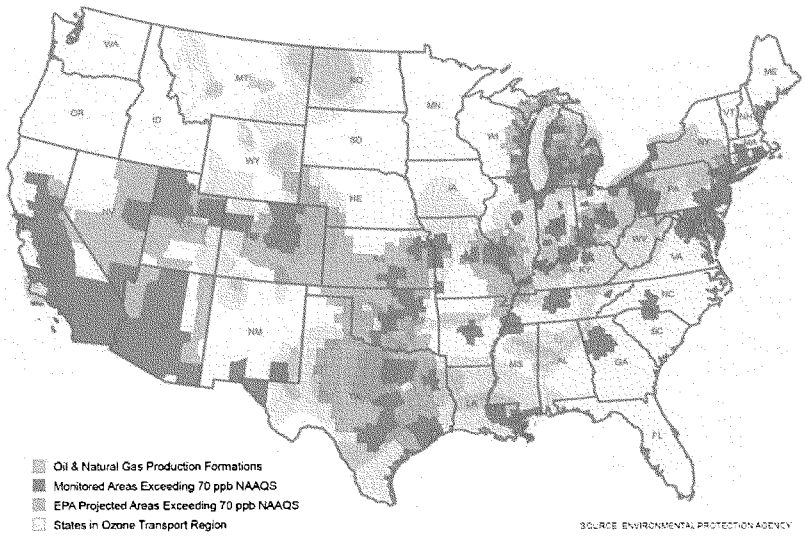
[56] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

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 proposal 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 proposal 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.

As EPA states with regard to the proposed Subpart OOOOa, "we [EPA] believe that the industry can bear . . . and survive."[57] However, no broad analysis of the collective impact of the CTG proposal on American oil and natural gas production in the context of the revised Ozone NAAQS has been done. Such an analysis should be done for several pertinent reasons.

[57] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

1. 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 current Ozone NAAQS of 75 ppb (8 hour) in 2020. Figure 3 presents EPA's assessment of its revised Ozone NAAQS by 2025.

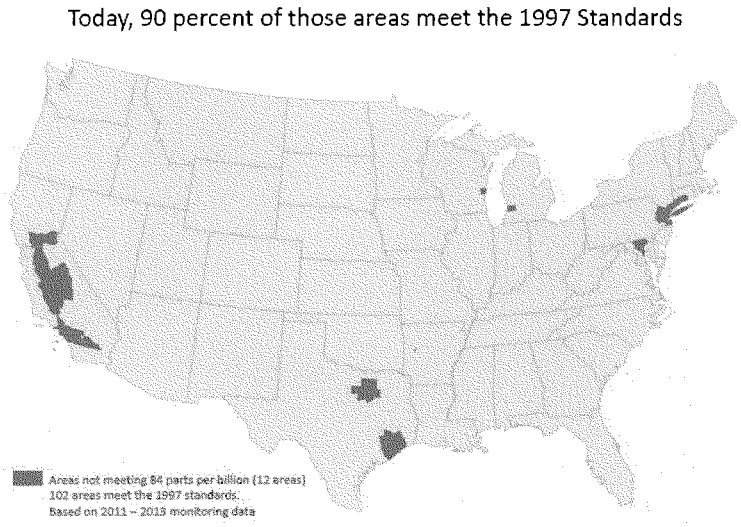
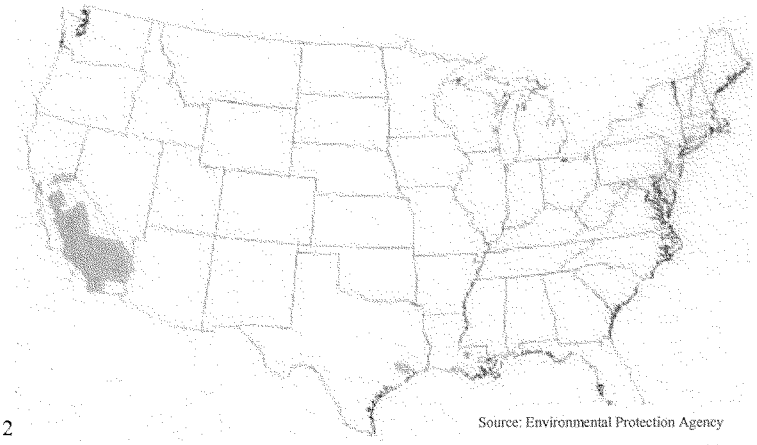


Figure 1

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



Source: Environmental Protection Agency

Figure 2

Figure 3

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 proposed NAAQS by 2025 and, realistically, any time until well after 2030. What this means is that EPA's claimed health benefits from the proposed 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 proposed NAAQS than they are under the current 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 current NAAQS as the new one. Adopting the revised NAAQS will produce the same regulatory requirements for these areas as the current NAAQS.

2. EPA has stated in its support documents for its revised 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 lower 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 lower 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 revised 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.

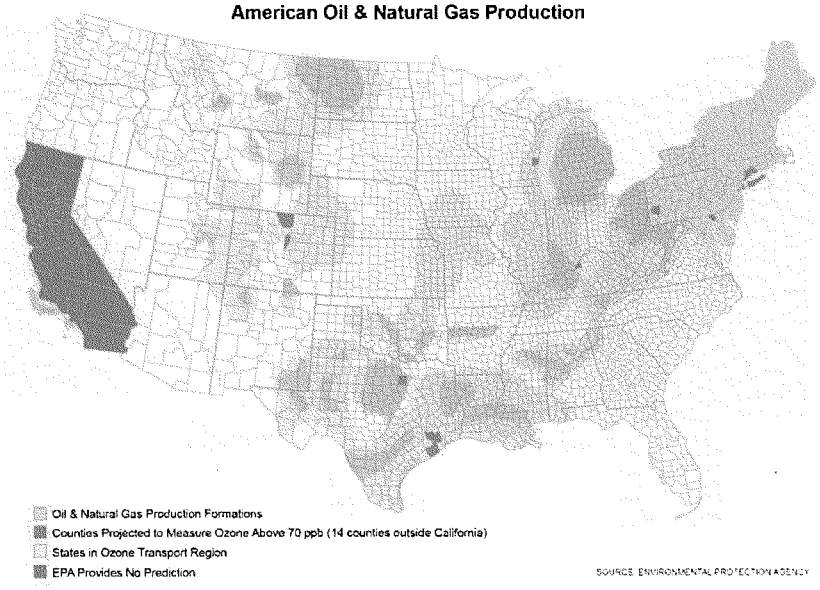
Once an area becomes subject to Part D, minimum requirements are mandated. For example, all new construction must not only comply with rigorous emissions controls, but all remaining emissions must be "offset" by reductions in existing emissions that are not otherwise regulated. Many of the areas that 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.

3. The proposed 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 revised 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.

For these reasons, EPA must fully assess the energy, economic and environmental consequences of implementing the proposed CTG in the context of the revised Ozone NAAQS. IPAA/AXPC believes that EPA cannot justify the current CTG at this time. 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 proposed 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. Finalizing the proposed 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. If EPA finalizes an oil and natural gas production CTG without assessing all of these consequences, it can only be viewed as arbitrarily ignoring significant implications that EPA has the responsibility to address.

It is pertinent to address the methane emissions issue here, too. While this proposed oil and natural gas production CTG is written to manage VOC emissions, it has been proposed as a part of the Administration's Climate Action Plan and is partly a surrogate for methane emissions management. However, as IPAA/AXPC stated earlier in these comments, the requirements already in regulation under Subpart OOOO more than achieve the Administration's methane reduction targets for the oil and natural gas production segment of the Climate Action Plan. This CTG needs to be addressed on its merits and its consequences weighed with regard to Ozone NAAQS nonattainment.

In addition to these general concerns, IPAA/AXPC has issues associated with the specific CTG proposals.

A. Fugitive Emissions

IPAA/AXPC identified a series of specific issues in the discussion of the Subpart OOOOa proposal that apply in the CTG context as well. Here, this discussion will focus on some of those issues and raise others that arise because of its application to existing sources.

First, EPA's approach to a fugitive emissions program fails to recognize the nature of these emissions at oil and natural gas production facilities. This emissions arena is characterized by "fat tail" emissions where a few components within the facility account for the overwhelming amount of the releases. At the same time, it is an arena where the appropriate regulatory formulation is still being identified. Several states have initiated fugitive emissions programs, and each differs from the others. Clearly, it will take some time to determine the efficacy of approaches in order to assure that a cost-effective program is defined. Into the middle of this uncertainty, EPA proposes the most burdensome approach with expectations of success that are not founded on experience. Rather than bullying its way into the arena, EPA has two far better approaches it could take. One is to watch the emerging state programs and use their results to design a program. The second is to work with industry to develop voluntary initiatives that would reflect the emerging understanding of fugitive emissions patterns. IPAA/AXPC believes that EPA should withdraw its fugitive emissions proposals until more is known about the best approaches to managing them.

Second, initial experiences with state programs are revealing that once a "fat tail" source is corrected through appropriate maintenance, its emissions do not increase – at least for long periods of time. In fact, because the current state programs have been operating for a limited

amount of time, some sources that have been fixed have not needed a second action. However, like its NSPS proposal, EPA creates a framework of shifting monitoring frequencies that are not justified based on experience. If EPA continues to pursue its proposal, it should rely on an annual inspection cycle to create a stable planning framework.

Third, when states have or create their own fugitive emissions programs, these programs should be considered as meeting CTG requirements.

Fourth, IPAA/AXPC supports excluding smaller facilities (e.g., marginal wells producing 15 barrels/day of oil equivalent or less) from the scope of the fugitive emissions program and believes that facilities that are initially included in any program should be excluded when their production falls below the threshold. IPAA/AXPC agrees that a fugitive emissions program should not apply to facilities with only a single wellhead. Further, EPA bases its program on a "model" facility with an expected number of components. IPAA/AXPC recommends that sites with less than the model facility components should be excluded from the fugitive emissions program.

Fifth, IPAA/AXPC believes that EPA is understating the costs of its fugitive emissions program and overstating its benefits. As IPAA/AXPC stated in discussing the NSPS proposal, EPA relies on technologies that are costly while not demonstrating those technologies are necessary to achieve benefits. For example, EPA is enamored with the use of specific OGI technologies. EPA places far too much faith that OGI can detect emissions accurately. Moreover, by using this technology, it drives compliance costs excessively. As described earlier, compelling the expenditure of more than $100,000 per FLIR camera is a burden not easily borne by existing operations where production rates are lower than new facilities in today's economic climate. EPA's proposal immediately demands confidence that the expenditure will result in substantial savings. However, nothing in EPA's CTG proposal demonstrates that it has realistically evaluated the effectiveness of this program at existing facilities. Past CTG have provided a threshold cost effectiveness test that is absent here. Rather, EPA calculates costs/ton of reduced emissions for various technologies whether they are appropriate as RACT. For example, EPA rather cavalierly discounts the costs/ton for oil wells – which exceeds $10,000/ton in all of its cases and reaches more than $25,000/ton in some – by stating "[t]he cost of control for natural gas well sites and gathering and boosting stations is considered to be reasonable."[58] Implicitly, the cost of control for oil well sites is not reasonable, but EPA proposes the same RACT requirements. IPAA/AXPC believes that oil well sites should be excluded from the CTG and that any natural gas well site program needs to be reconstructed to focus on high-emitting sources with flexibility to use more cost-effective approaches.

EPA errs in locking in current technologies, like OGI, that may well be far less cost-effective than new approaches that may arise as state programs learn from experience. As with the NSPS proposal, EPA needs to allow the development of knowledge in managing these fugitive emissions before framing a rigid and ineffective mandate.

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[58] U.S. Environmental Protection Agency. Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft). (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

B. Storage Vessels

There is a vast difference between regulating new storage vessels and existing ones. Specifically, a new vessel can be designed to accommodate a vapor collection system whether it is for recovery or combustion. Once built, both the vessel and the system can be maintained to assure that they are operating effectively and safely. Because a CTG addresses existing facilities, there is no certainty that the storage vessels will be capable of accepting the equipment needed to capture vapors. Vessels deteriorate over time despite maintenance, and if the structural integrity is compromised by the additional equipment, a safety issue arises.

In this context, and more generally, EPA's cost estimates must be scrutinized. EPA suggests that vapor recovery units (VRU) or combustors can be considered RACT for vessels with emissions of 6 tons/year or more. However, if a storage vessel cannot safely operate with additional equipment, the entire vessel would have to be replaced, if replacement is even economically feasible. EPA does not consider this situation in calculating its cost effectiveness, but it should because the consequences would considerably change the determination of RACT. For example, at some facilities under current economic conditions, the cost of a new storage vessel would not be economically feasible based on the facility's production rates.

Additionally, IPAA/AXPC believes that marginal well facilities should be excluded from the scope of the CTG. Clearly, the burden of adding capture equipment – and certainly the burden of replacing storage vessels – cannot be readily borne by marginal well operations. EPA relates emissions to production rates as shown in the following table. The information contained in the table shows that marginal well operations fall well below even EPA's presumed RACT threshold of 6 tons/year. Consequently, rather than deliberate on emissions estimates, the straightforward approach to defining the scope of the storage vessel CTG would be to exclude marginal well operations. Similarly, when a facility's production levels fall to the point when it becomes a marginal well operation, it should no longer be required to operate any vapor capture system. Beyond that, there should be the opportunity – like there is in Subpart OOOO – to demonstrate that uncontrolled emissions levels are below 4 tons/year to obtain an exclusion from the storage vessel CTG.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[13]

Production Rate Bracket (BOE/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	Condensate Storage Vessel VOC Emissions (tpy)[c]
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a] BOE=Barrels of Oil Equivalent
[b] Oil and condensate production rates published by EIA. "US Total Distribution of Wells by Production Rate Bracket." http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html
[c] Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.
[d] There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

C. Pneumatics

The proposed CTG addresses both pneumatic controllers (regulated for new sources under Subpart OOOO) and pneumatic pumps (proposed for new source regulation under Subpart OOOOa). IPAA/AXPC believes that these requirements should not apply to marginal well facilities. In addition, EPA needs to clarify that the CTG does not apply to pneumatics with continuous emissions less than 6 scf/h.

D. Compressors

The proposed CTG addresses a subset of compressors as follows:

(a) *Centrifugal compressors*. Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.[59]

However, it makes no distinction based on the size of the facility. IPAA/AXPC believes that the CTG should not apply to marginal well facilities and that its application should be terminated when a facility becomes a marginal well operation.

E. Conclusion

The proposed oil and natural gas production CTG should be withdrawn. It fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. It largely ignores the differences between the oil and natural gas production industry and other industry segments that require recognition of the significant differences across the industry in the size and scope of operations. These differences dramatically impact the economic implications of controls. While a portion of the CTG proposal creates an application threshold that excludes marginal oil and natural gas wells, a similar provision should apply to all of its provisions but does not. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

VI. Comments on Source Determination Proposal

The EPA is soliciting comments on a potential revision of the process for determining the nature of a source for certain emissions units in the oil and natural gas sector. Among these are facilities that produce oil and natural gas. The proposal addresses CAA new source permitting

[59] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

under the Prevention of Significant Deterioration (PSD) program, the Nonattainment New Source Review (NNSR) program, and Title V permitting program. IPAA/AXPC believes that establishing certainty regarding source determinations provides an important benefit to the permitting process. Below are a series of recommendations and comments that address IPAA/AXPC's concerns regarding the EPA proposal. However, at the outset, IPAA/AXPC would observe that, while there have been some specific issues associated with past interpretations of oil and natural gas production sources, the issue of source determination applies to all stationary sources.

Similarly, this issue of changing the structure of source determination must conform to the constraints of past interpretations. As EPA characterizes its actions on source determination in the Federal Register:

> Adhering to the statutory language in CAA section 111(a)(3), we have defined the term "stationary source" to mean "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant" [40 CFR 52.21(b)(5); 40 CFR 51.165(a)(1)(i); 40 CFR 51.166(b)(5)]. We have then further defined the four statutory terms "building, structure, facility, or installation" collectively in our NSR regulations to mean "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control)," where the "same industrial grouping" refers to the two-digit Standard Industrial Classification code [40 CFR 52.21(b)(6); 40 CFR 51.165(a)(1)(ii); 40 CFR 51.166(b)(6)]. These three regulatory factors: (1) Same industrial grouping; (2) location on contiguous or adjacent properties; and (3) under the control of the same person or persons must be evaluated on a case-by-case basis for each permitting decision.[60]

EPA needs to confirm clearly that its actions on source determination operate within this larger framework.

EPA presents two approaches to source determination. These comments focus principally on Option A – defining the source based on proximity – because IPAA/AXPC strongly opposes Option B, which includes exclusively functionally interrelated equipment.

Much of the history of the source determination question for oil and natural gas production occurred prior to the significant shift in development to shale formations and the evolution of technology that has been so successfully applied to produce those resources. These changes in the nature of oil and natural gas development alter the physical aspects of producing operations. Oil and natural gas production operations have moved from a framework where numerous vertical wells were drilled in developing a resource play to a framework where development relies on significant horizontal legs providing access to the resources. Correspondingly, a typical well site will now include numerous individual wells ranging from six

[60] Source Determination for Certain Emission Units in the Oil and Natural Gas Section, 80 Fed. Reg. 56,579, 56,580 (Sept. 18, 2015) (to be codified at 40 C.F.R. pts. 49, 51, 52, *et al.*).

to twelve to, sometimes, twenty. As a result, the concepts that drove past EPA actions to consider source determination approaches that aggregate multiple well sites together – essentially the "daisy chaining" concept the EPA seeks to avoid in this proposal – no longer reflect the industry's common practices.

Similarly important, the regulatory structure that affects oil and natural gas production has changed significantly. Since the beginning of 2015, the industry has been subjected to NSPS requirements on completions of new hydraulically fractured natural gas wells, pneumatic controllers, and storage vessels. Currently pending are proposals to regulate new hydraulically fractured oil wells, pneumatic pumps, compressors, and fugitive emissions. These regulations apply to virtually every new well site and manage the emissions. Consequently, the issue of emissions management is essentially settled, and the principle issue of the source determination rule will be the regulatory burden for the specific permitting programs of the proposals – PSD, NNSR, and Title V. Because emissions are not the driving factor in the decision, EPA should move toward limiting burdens rather than expanding them.

These factors shape our view that Option A – *Define Source Based on Proximity (Similar to the NESHAP)* – is the far better framework to address source determination. As EPA characterizes Option A:

> Under the first, and currently preferred, option for which the EPA is taking comment, the EPA proposes to define "adjacent" such that the source is similar to that in the NESHAP for this industry, Subpart HH, National Emissions Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities (40 CFR 63.760). Under this option, the "source" for oil and natural gas sector activities is presumed to be limited to the emitting activities at the surface site, and other emitting activities will be considered "adjacent" if they are proximate. Thus, under this first option, two or more surface sites must be considered as a single source if they share the same SIC code, are under common control, and are contiguous or are located within a short distance of one another.
>
> We prefer this option because we believe that a definition that centers on a surface site is familiar to the industry and the regulators because of the current NESHAP requirements, so it will streamline permitting. We also believe that a definition focused on a surface site most closely represents the common sense notion of a plant for this industry category. Surface sites that are not in close proximity to one another may be on a separate lease which may not align with the common sense notion of a single plant. In addition, we believe that this definition is consistent with Congress' intent, at least as they expressed it with regard to [hazardous air pollutants (]HAPs[)], as discussed previously.[61]

IPAA/AXPC essentially agrees with EPA's characterization and its rationale. Where IPAA/AXPC differs relates to an issue where EPA seeks specific comments – whether it is

[61] *Id.* at 56,586-7.

appropriate to establish a specific distance within which to consider multiple surface sites as a single source, and if so, what that distance should be. EPA is proposing a distance of a ¼ mile. IPAA/AXPC believes that EPA should, instead, adhere to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.

This approach improves on the proximity concept because it avoids picking an arbitrary distance, such as a ¼ mile. Moreover, it readily addresses another issue that EPA raises – "daisy-chaining". EPA is correct to be concerned that linking one site to another through its proximity invites the opportunity to link a third or a fourth or more sites solely on the basis of proximity. There is no value in daisy-chaining since the individual sites are each subject to the emissions management requirements under the appropriate NSPS or whatever additional regulations apply.

If, however, EPA persists in utilizing a specific distance, it is correct that some states use ¼ of a mile as a bright line to exclude needless source determinations for facilities outside that distance. However, most states then conduct a case-by-case source determination for facilities inside the ¼ mile based on proximity and the "common sense notion of a plant." Therefore, if EPA persists in utilizing a specific distance, it should follow the example of most of the oil and gas producing states and use the bright line to trigger a case-by-case source determination inside that bright line. It is also important to recognize that using an arbitrary distance raises questions of daisy-chaining, and EPA should have language either in the rule or the preamble to state that facilities should not be daisy-chained. EPA has also asked from where a specific distance should be measured. We suggest that the distance be based on the center of the new source triggering the source determination to the center of any nearby facility.

EPA should reject Option B – *Define Source To Include Exclusively Functionally Interrelated Equipment*. Option B essentially invites daisy-chaining. It creates the opportunity to link multiple facilities regardless of the distances between them. For example, as EPA states "[e]xclusive functional interrelatedness might be shown by connection via a pipeline or other means, because of the physical connection between the equipment."[62]

This characterization largely parrots the circumstances in the *Summit Petroleum Corp. v. U. S. Environmental Protection Agency*, 690 F.3d 733 (6th Cir. 2012) case. In this case, as EPA describes in its discussion of these proposals:

> In the decision, the Court said that the EPA's use of interrelatedness in determining whether sources were "adjacent" is unreasonable and contrary to the plain meaning of the term as currently used in EPA's regulations. The two judges in the majority found that the term "adjacent" was unambiguous and its plain meaning related only to physical proximity, and thus could not include

[62] *Id.* at 56,587.

> consideration of functional interrelatedness. The EPA sought rehearing of the Court's decision, but that request was denied.[63]

Why EPA would suggest moving back toward this judicially rejected approach is unfathomable. More importantly, it does not create any environmental benefits, because, as stated above, the existence of the current and proposed EPA oil and natural gas production regulatory requirements would apply to the separate facilities. Option B would only create substantially expanded regulatory burdens.

In conclusion, IPAA/AXPC believes that EPA's appropriate choice is a modified Option A relying on the use of a contiguous border to aggregate sources if aggregation is appropriate. To facilitate clarity on this issue, IPAA/AXPC suggests adding the following definition where appropriate in the Code of Federal Regulations:

> "Contiguous or adjacent properties" mean surface areas with an affixed building, structure, facility or installation including permanently graded or cleared areas for such building, structure, facility or installation, that share an edge/boundary, physically touch, and are adjoining or physically abutting.

CONCLUSION

IPAA/AXPC values the opportunity to comment on the above referenced regulatory proposals. The oil and natural gas production industry has worked closely with EPA over the past decade to promulgate reasonable, cost-effective regulations on air emissions. While industry objected to various aspects of the Subpart OOOO regulations controlling VOC emissions from various sources within the oil and natural gas sector, through the administrative reconsideration process and revisions to Subpart OOOO, many of the issues have been addressed without protracted and costly litigation. The proposed Subpart OOOOa and CTG regulations seem to represent a departure from a willingness on the part of this Administration to promulgate reasonable, cost-effective, and most importantly, needed regulations.

EPA's pollutant of concern is methane. Unlike other "pollutants" and other industrial "products," methane is not treated as a pollutant in the oil and natural gas industry – it is a valuable product. Unlike other industries, market forces are constantly at work to minimize what EPA views as a pollutant and our industry views as a product. The fact methane is a primary constituent of what this industry produces explains, in large part, why emissions from the exploration and production segment of the oil and natural gas sector have gone down while production has gone up (see Section I above). In reality, most of the reductions are a function of voluntary measures by producers to retain/capture methane or state regulatory programs where oil and natural gas production has increased dramatically in the past decade.

A central theme to IPAA/AXPC's comments is that the proposed Subpart OOOOa regulations are unnecessary and the CTG proposed regulations are, at best, premature. The

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[63] *Id.* at 56,584.

EPA's legal foundation and basis for the proposed Subpart OOOOa and CTG regulations are dubious and invite legal challenge. It is arbitrary and capricious for EPA to base its proposed methane regulations (NSPS and CTG) on a model that predicts the social cost of methane. The irony is that EPA can accomplish a majority of its goals with modifications to existing regulations and attainment of the current Ozone NAAQS. The cost of EPA's proposed NSPS and CTG is not justified.

A. Proposed Methane New Source Performance Standards Summary Comments

- Regulations cannot be based on what EPA "believe[s]" "the industry can bear . . . and survive."[64]
- EPA's "consistency," patchwork "endangerment finding," and global warming concerns do not warrant direct regulation of methane emissions from the oil and natural gas sector.
- EPA's failure to evaluate the cost associated with the potential regulation of existing sources under Section 111(d) is arbitrary and capricious.
- States (and operations within those states) should not be penalized for taking early action to address emissions from the oil and natural gas sector, i.e., compliance with essentially equivalent state programs should be deemed compliance with the finalized Subpart OOOOa regulations.
- EPA's focus on fugitive emissions at well sites and compressor stations is premature and not supported by reliable cost/benefit data.
    - EPA's request for input and comment on numerous aspects of the proposed regulations is indicative of an issue that regulators and industry are still learning to address.
    - The "corporate fugitive management program" is a logical way to address the issue, but regulators and companies need time to determine what such a program should look like.
    - EPA's cost-effectiveness analysis for the proposed regulatory package suffers from shortcomings on both sides of the equation: for the reasons set forth above, the costs are understated and the benefits are overstated or unsupported.
    - States with the most active shale plays are learning valuable information on how to reduce fugitive emissions. EPA should not rush to judgement and establish federal standards that will be inconsistent, duplicative and potentially unnecessary because of state efforts.
    - For the reasons stated above, EPA should not dictate a specific technology for determining "leaks." OGI may be appropriate in certain instances, but EPA's selection of one technology is arbitrary and capricious.
    - EPA's proposed approach to determining the frequency of LDAR surveys based on percentage of leaking components demonstrates its lack of understanding of the issues associated with fugitive emissions. As discussed above, EPA's

[64] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

proposed regulations would impose significant costs on the industry with dubious environmental benefit.
    - IPAA/AXPC supports EPA's proposed exclusions but seeks clarification that the 15 boe exclusion also serves as an off ramp to reduce the burden of the proposed regulations.
- Oil well RECs are not the same as RECs at natural gas wells.
    - IPAA/AXPC questions if EPA has documented new information to justify the cost-effectiveness of RECs on oil wells. The economics and engineering limitations at oil wells are different than natural gas wells, and EPA has failed to adequately differentiate between the two and justify RECs at oil wells.
    - IPAA/AXPC supports the limited exclusions to the oil well REC requirements but suggests clarification as to the requirements associated with noncombustible gas.
- EPA's proposed regulation of pneumatic pumps fails to adequately reflect the complexity, cost, and safety issues associated with sending captured natural gas to an existing combustion device. IPAA/AXPC believes that if the costs associated with such complexity were adequately reflected, the proposed regulations would not be cost effective.
- IPAA/AXPC supports EPA's proposed regulations that indicate the compressor rules do not apply to compressors at the wellsite but requests clarification that a similar exclusion applies under the proposed CTG.

B. Proposed CTG Summary Comments

- The CTG regulations must be based on a technological analysis for RACM instead of arbitrarily transposing new source BSER requirements to existing sources.
- The CTG regulations need to recognize differences across the oil and natural gas production industry that recognize size and scope of operations.
    - Marginal oil and natural gas production facilities should be excluded from all of the CTG.
- The CTG regulations must be based on their applicability to manage VOC emissions in Ozone NAAQS nonattainment areas.
    - EPA has failed to provide justification for the CTG as necessary for Ozone NAAQS attainment and, in reality, EPA's projections of Ozone NAAQS attainment in 2025 demonstrates the CTG are not necessary.
    - Implementation of the CTG in the absence of a demonstrated need is counterproductive and unnecessarily constrains economic growth.

C. Proposed Point Source Determination Summary Comments

- EPA should adopt a Source Determination definition that adheres to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.
- EPA should reject the use of functionally related equipment as a consideration in adopting revisions to its Source Determination definition.

If EPA has any questions or concerns, please do not hesitate to contact us.

Sincerely,

Lee Fuller
Executive Vice President
Independent Petroleum Association of America

V. Bruce Thompson
President
American Exploration & Production Council

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
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ATTACHMENT A

ACRONYM INDEX

AAPL	American Association of Professional Landmen
AEO	Annual Energy Outlook
AESC	Association of Energy Service Companies
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR5	Fifth Assessment Report
AVO	audio/visual/olfactory
AWEA	American Wind Energy Association
AXPC	American Exploration and Production Council
boe	barrels of oil equivalent
BSER	best system of emission reductions
CAA or Act	Clean Air Act
CMSA	Consolidated Metropolitan Statistical Area
CTG	Control Technique Guidelines
EIA	Energy Information Administration
FLIR	forward looking infrared
GHG	Greenhouse Gas
GOR	gas-to-oil ratio
HAPs	hazardous air pollutants
IADC	International Association of Drilling Contractors
IAGC	International Association of Geophysical Contractors
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
LDAR	leak detection and repair

NAAQS	National Ambient Air Quality Standards
NCA3	2014 National Climate Assessment, Climate Change Impacts in the United States
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGO	non-governmental organizations
NNSR	Nonattainment New Source Review
NSPS	New Source Performance Standards
NSWA	National Stripper Well Association
NYMEX	New York Mercantile Exchange
OGI	optical gas imaging
OTR	ozone transport regions
PESA	Petroleum Equipment & Services Association
PSD	Prevention of Significant Deterioration
RACM	Reasonably Available Control Measures
RACT	reasonably available control technology
RECs	reduced emissions completions
RIA	Regulatory Impact Analysis
SCADA	supervisory control and data acquisition
SCC	social cost of carbon
SC-CH_4	social cost of methane
SIC	Standard Industrial Classification
SIPs	State Implementation Plans
TSD	Technical Support Document
USG	United States Government
USGCRP	U.S. Global Change Research Program
USOGA	U.S. Oil & Gas Association

VOC	Volatile Organic Compoun
VRU	vapor recovery units
WEA	Western Energy Alliance

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December 4, 2015

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

Attention: Docket ID Number EPA-OAR-2010-0505
Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Environmental Protection Agency's (EPA's) "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" at 80 FR 56593 (September 18, 2015)

Dear Administrator McCarthy:

American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA's) "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" at 80 FR 56593 (September 18, 2015).

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Collectively, they provide most of the nation's energy and many will be directly impacted by the proposed regulations.

The proposed rule is part of the President's "Methane Strategy," which includes multiple regulations and programs from several different agencies, intended to further reduce greenhouse gas emissions from oil and natural gas operations. However, it's important to take into account the recent methane emission trends associated with our industry. Even as U.S. oil and natural gas production has surged, methane emissions have declined significantly. For example, EPA's GHG inventory shows methane emissions from hydraulically-fractured natural gas wells have fallen nearly 79 percent since 2005 and total methane emissions from natural gas systems are down 11 percent over the same period. According to the Energy Information Agency, these reductions have occurred during a time when total U.S. gas production has increased 44% and, as a result of the increased use of natural gas, CO2 emissions from the energy sector are now near 20-year lows. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment as we bolster our nation's energy security.

Each of the proposals (Control Techniques Guidelines, Source Determination, Minor Source Tribal NSR), including this one, has potentially significant impacts on our industry's operations and, collectively, they have the potential to hinder our ability to continue providing the energy our nation demands. These cumulative impacts must be considered in conjunction with the impacts of the lowered ozone standards and the pending Bureau of Land Management (BLM) methane rule, which has not yet been proposed and will likely require costly methane controls for some of the very same emission sources. Our organizations have collaborated well in the past and API remains committed to working with EPA and the Administration to identify emission control opportunities that are both cost-effective and, when implemented, don't impact safety or hinder our ability to provide the energy our nation will continue to demand for many years to come. Attached are our comments on the "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" as well as an executive summary.

As we noted in our comment extension request, we again request that EPA officially re-open the docket for all three rulemakings when the proposed BLM methane rule is published in the Federal Register, to allow additional time for public comment once its interrelationship with the EPA proposed regulations can be fully analyzed. Also, given the limited comment period and minimal extension for these complex proposals, API will continue its review and, if warranted, provide supplemental comments to the agency that we request be included in the appropriate docket to protect the record and considered before finalizing the rules.

We look forward to working with you and your staff as these rules are developed. If you have any questions regarding the content of these comments, please contact Matthew Todd (toddm@api.org, 202-682-8319).

Sincerely,

Howard J. Feldman

Howard J. Feldman

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA
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Chris Stoneman, EPA
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Attachment

API Comments on the Proposed Rulemaking – Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution

December 4, 2015

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

EXECUTIVE SUMMARY

As detailed in our comments, API has numerous concerns with EPA's proposed New Source Performance Standard (NSPS) rulemaking for the oil and natural gas sector (40 CFR Part 60, Subpart OOOOa). EPA has indicated the desire to finalize the proposed rule in June of 2016. We are concerned that this artificial deadline will hinder the agency's ability to adequately address stakeholder comments and develop a final rule that protects the environment and does not hinder America's energy renaissance. This is an unrealistic schedule for issuing a complex rule with the concerns identified that cover oil and natural gas industry segments as large and diverse as the onshore production, processing, and transmission and storage segments. EPA has only a few months to review and analyze all the submitted comments, make appropriate revisions, and complete the necessary internal and interagency reviews. As such, EPA should take sufficient time between the close of the comment period and promulgation of the final rule to adequately consider and address public comments.

Many of API's concerns stem from the broad applicability of the proposed rule and the one-size-fits-all approach to regulating an industry that varies greatly in the type, size and complexity of operations. EPA has justified the proposed regulation using economic studies on "average model facilities" without determining whether the resulting proposed control requirements are appropriate for the entire range of sources included in the source category. The proposed rule applies NSPS in unique and unprecedented ways to categories and equipment not previously listed, while relying on unsound legal justification. The notification, monitoring, recordkeeping, performance testing and reporting requirements are significantly more burdensome than justified for the small and/or temporarily affected facilities.

Listed below are API's primary concerns with the proposed rule. To facilitate review of our comments, API has summarized the concern and provided a recommendation with a reference to the detailed comments where additional supporting discussion has been included.

Direct Regulation of Methane is Unlawful

Issue – Section 111 of the Clean Air Act (CAA) requires the Agency to list a category of stationary sources if, in the Administrator's judgment, the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA §111(b)(1)(A). It is unlawful for EPA to regulate only methane from oil and natural gas sources based on an endangerment finding that is largely attributable to other GHG pollutants from non-stationary sources. In the 2009 endangerment finding for motor vehicles, EPA found that "carbon dioxide is expected to remain the dominant anthropogenic greenhouse gas, and thus driver of climate change." See, e.g., 74 Fed. Reg. at 66519. Given that EPA concluded that carbon dioxide from motor vehicles—not methane— is the "driver of climate change," EPA cannot rely on that past finding in a rule that regulates only methane. EPA has not shown that there is a rational basis for concluding that methane, a single element of the aggregate pollutant GHGs, meets the endangerment standard called for in the CAA, or that upstream oil and natural gas sources are a significant contributor of methane. Both showings are legal prerequisites before EPA may propose Subpart OOOOa.

Recommendation – EPA must make both an endangerment and significant contribution finding for each pollutant that it seeks to regulate for a given source category. In this case, an endangerment finding must be made for methane specifically, and a significant contribution finding must be made for the proposed covered sources.

Refer to Comments 3.0 and 4.0 for detailed comments on this matter.

Direct Regulation of Methane is Unnecessary

Issue – In the proposed rule, EPA states that, for some of the regulated affected facilities, direct regulation of methane accomplishes no further reduction in methane emissions than would occur through regulation of VOC alone. EPA recognizes that under its proposal, the same controls would be required for VOC and methane as are currently required for VOC under Subpart OOOO. EPA's decision to directly regulate methane from those same sources covered by OOOO, despite this admission - which means that no significant additional methane emissions reductions will occur - is arbitrary and capricious. There is no rational basis for taking the wholly discretionary action of regulating methane or GHGs from this part of the oil and natural gas sector where EPA would achieve no additional methane reductions beyond those achieved through existing VOC standards. None of EPA's asserted reasons have merit, and therefore, EPA has not made a showing that revision of the standards is "appropriate," as required under section 111(b)(1)(B).

Recommendation – EPA should continue the practice of indirectly regulating methane through the use of natural gas as a surrogate for VOC.

Refer to Comment 7.0 for detailed comments on this matter.

EPA Needs to Address Permitting Implications Associated with Regulation of Methane

Issue – EPA has not addressed the possible permitting implications that would flow from of the direct regulation of methane. Unintended implications could include allowing methane alone to trigger PSD and Title V permitting for all sources, not just oil and natural gas sources, which would greatly increase permitting burdens and result in costs that EPA did not consider in the rulemaking. API has raised PSD permitting issues previously with the EPA and understands that EPA does not intend for NSPS OOOOa to trigger PSD and Title V permitting applicability as that runs counter to both Congressional intent and judicial precedent. Agencies and states cannot handle an increased permitting burden, and such a trigger would drastically increase the number of permits submitted, not only for the oil and natural gas sector, but for all sectors.

Recommendation – As a threshold matter, API presents the following solution to the PSD and Title V permitting issues without conceding its position that EPA is required to make a separate endangerment finding for methane and a significant contribution finding for methane from this source category. To address the possible PSD and Title V permitting implications, EPA should adopt an approach similar to that taken in the Clean Power Plan (NSPS Subpart TTTT). Specifically, EPA should make it clear that the pollutant being regulated under NSPS OOOOa is the group of six GHGs. EPA should also make it explicitly clear that methane is being used as a surrogate for the group of six. Additionally, EPA should include an explanation as well as a provision in the final rule that extends the Tailoring Rule to cover regulation of GHGs under NSPS OOOOa.

Refer to Comment 6.0 for detailed comments on this matter.

Equipment Leak Requirements

Issue – EPA has proposed a process that requires significant, unnecessary recordkeeping and reporting and requires surveys of sites that are proven to have little to no detectable leaks. Associated proposed definitions unnecessarily complicate compliance. Additionally, the initial semi-annual frequency is not warranted, and the complex process for determining frequency introduces a burdensome paperwork exercise with no emissions reduction benefit. Closed vent systems (CVS) should not be subject to duplicative requirements. As well, leak detection should not be duplicative with other state or federal enforceable leak detection requirements.

Recommendation –Streamline program to require annual inspections at sites with a compressor or storage vessel. Eliminate the requirement for a site-specific monitoring plan. Existing programs demonstrate that monitoring with an annual frequency results in very low emissions. A companywide monitoring plan will cover all the relevant material; there is no added benefit and significant added cost of developing thousands of site-specific monitoring plans. Revise definitions according to our recommendations. CVS monitoring requirements should be the same as those for fugitive emission components. Finally, exempt sites subject to state, local, or other federally enforceable leak detection programs.

Refer to Comment 27.0 for detailed comments on this matter.

Pneumatic Pump Applicability and Technical Feasibility

Issue – EPA is proposing to regulate low emitting sources which would add considerable expense and burden while providing very limited environmental benefit. EPA has ignored critical technical and safety issues in assuming that pneumatic pumps can be readily connected to existing closed vent systems. There are numerous potential safety and operational issues with connecting the discharge from a pneumatic pump to an existing control device and closed vent system. These issues can impact both the performance of the pump and result in back pressure on the other sources being controlled.

Recommendation – EPA should exempt low emitting pumps and low usage pumps, i.e. pumps that emit at an equivalent rate lower than a high bleed controller. This would be consistent with the position taken in Subpart OOOO and reinforced under the Subpart OOOOa proposal for pneumatic controllers. EPA should also provide an exemption from the requirements to control pump emissions where it has been determined to be technically infeasible or potentially unsafe.

Refer to Comment 24.0 for detailed comments on this matter.

Oil Well Completions

Issue – EPA needs to accommodate additional exemptions for certain oil well completions. There are a wide range of conditions experienced across different oil and natural gas fields and additional provisions are needed in the rule to clearly exempt certain scenarios.

Recommendation – In addition to the exemption for wells producing less than 300 scf of gas per bbl of oil, EPA should include exemptions for wells requiring artificial lift to complete flowback and for periods when flowback has stable entrained gas, foam, emulsion, or infrequent slugging gas flow such that a separator cannot be operated.

Refer to Comment 22.2 for detailed comments on this matter.

EPA Must Recognize Implementation Challenges

Issue – As we learned in the development of Subpart OOOO, API urges EPA to exercise caution in the development of these rules to allow operational flexibility as it seeks "one size fits all" regulatory solutions. Consideration must be given to the implementation of these new rules to ensure industry is able to comply. Consistent with the original Subpart OOOO rulemaking, EPA should consider a similar compliance schedule for the proposed NSPS rule. We would also urge EPA to accommodate operators that are currently implementing leak monitoring and repair requirements, whether due to existing air permits, state or local regulations or voluntary commitments, to satisfy the federal rule requirements and minimize regulatory burden for those operators.

Recommendation – If promulgated as written, EPA should allow a phased implementation for completion, pneumatic pump, and leak detection and repair (LDAR) requirements to accommodate the number of affected facilities and the associated engineering, implementation and training needed to comply with the new rules.

Refer to Comments 22.5, 24.0 and 25.0 for detailed comments on this matter.

Compliance Assurance Requirements for Subpart OOOOa Are Overly Burdensome

Issue – The monitoring and testing requirements are overly burdensome for Subpart OOOOa. The remote, dispersed and unmanned nature of facilities that lack electrical power, make the requirements logistically impractical, technically difficult and uneconomic. The use of NESHAP HH major source-type compliance requirements for storage vessels is confusing and unjustifiably stringent for NSPS.

Recommendation – CPMS requirements for monitoring centrifugal compressors and pneumatic controllers should be eliminated in lieu of the sensory inspections required for storage vessels. Additionally, the performance testing requirements should be revised.

Refer to Comment 12.2 and 12.4 for detailed comments on this matter.

Subpart OOOO Retroactive Requirements

Issue- EPA proposed several new requirements for control devices and closed vent systems to subpart OOOO that could be viewed as new requirements to be applied retroactively to affected facilities initially constructed between August 23, 2011 and September 18, 2015. This is inappropriate as NSPS rule changes may only be prospective and not retrospective. Amongst the numerous changes, proposed paragraph §60.5370(d) encapsulates the problem best by stating: *You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.* This suggests that new requirements in subpart OOOOa for subpart OOOO affected facilities will be applicable when subpart OOOOa is finalized. The only purpose for modifying subpart OOOO should be to end date the rule since it is being replaced with subpart OOOOa.

Recommendation – EPA should remove all new compliance requirements being proposed in subpart OOOO and only finalize changes to paragraphs §60.5360 and §60.5365 which end date the applicability of subpart OOOO and that correct issues that do not add new regulatory burden.

Refer to Comment 19.0 for detailed comments on this matter.

Multipollutant Cost Effectiveness Approach is Not Appropriate

Issue – In justifying the proposed requirements, EPA utilized a multipollutant approach to determine if costs were reasonable. EPA's reliance on the multipollutant methodology is arbitrary and capricious because it is inconsistent with EPA's own "rational basis" test for determining whether regulation of an additional pollutant from a source category is appropriate. As EPA clearly states, under its "rational basis" test, the Agency must have a rational basis for regulating *each* "pollutant." *See* 80 Fed. Reg. at 56601. EPA's multipollutant approach is inconsistent with that test because it allows the Agency to find that regulation of multiple "pollutants" is reasonable where regulation of each pollutant individually would not be. *See id.* at 56636.

Recommendation – EPA must re-evaluate and only assess the reasonableness of costs based on each pollutant.

Refer to Comment 10.0 for detailed comments on this matter.

Social Cost of Methane

Issue – EPA has inappropriately applied a social cost of methane (SC-CH_4) estimate that is highly speculative, not sufficiently peer-reviewed, and ultimately not suitable for policy applications. The SC-CH_4 is based on the approach used for quantifying the social cost of carbon (SCC) and therefore carries with it all of the same challenges to accurately calculating the benefits of the rule, and seriously affect the scientific and economic reliability of the SC-CH_4. The peer-reviewers selected by EPA did not reach a consensus and all found inconsistencies and other issues with the calculations used to generate the SC-CH_4, as did an independent review by NERA. The issues associated with the estimation and use of the SC-CH_4 include: differences in the way methane emissions was included in the three models; significant differences in the damage functions between the models; issues with the averaging approach used to synthesize the results; the inclusion of an unjustifiably low discount rate given the short atmospheric lifespan of CH_4; the inclusion of global benefits rather than domestic benefits; and the *ad hoc* nature of EPA's assumption of the indirect effects on radiative forcing. Independent review by NERA found that the benefits provided by the rule, after compensating for flaws in EPA's calculation, could be as much as 94% lower. When combined with the revised cost estimates and reduced emission benefits found by ERM, the rule could result in net costs of more than $1 billion in 2025.

Recommendation – There are significant uncertainties inherent in the newly-developed social cost of methane (SCM) calculation, and it may significantly overestimate methane's environmental impacts. Further, there has been a lack of adequate peer review for the SC-CH_4 estimate. As such, EPA's use of the social cost of methane is inappropriate to justify this rulemaking.

Refer to Comment 21.0 for detailed comments on this matter.

Next Generation Compliance

Issue – API believes the Next Generation Compliance Options discussed in the proposal preamble are unnecessary and represent an overreach by EPA of its authority. API believes the Next Generation Compliance Alternatives discussed in the preamble are not feasible or legal, nor do they achieve goals of assuring better compliance.

Recommendation – EPA must justify the legal basis for and formally propose any Next Generation Compliance provisions in a separate rulemaking before adopting them.

Refer to Comment 18.0 for detailed comments on this matter.

Electronic Reporting

Issue – EPA should not write electronic reporting into Subpart OOOO and Subpart OOOOa until the system is able to accommodate the unique nature of the oil and natural gas industry. The electronic reporting system is not proven generally at this time. Further, the system will require configuration to allow the current area based reporting vs facility by facility. In the past, system revisions have resulted in significant IT challenges, and appropriate time needs to be allowed for the agency to develop, QA/QC, user test and train reporters on the new system.

Recommendation – EPA should amend the final rule language to formally allow for continuation of current reporting approaches (under Subpart OOOO) for three years to allow for rollout of the electronic reporting system..

Refer to Comment 11.0 for detailed comments on this matter.

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Attachment B – API Comments on EPA's NSPS Electronic Reporting Proposal

Attachment C – Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

Attachment D – API Comments on EPA's White Paper on Liquids Unloading

Attachment E – API's Review of EPA's Cost Benefit Analysis

Attachment F – Comparison of the LDAR Requirements Proposed in Subpart OOOOa to Existing State LDAR Program

The document in its entirety can be found here: http://www.api.org/news-policy-and-issues/letters-or-comments/2016/07/16/api-comments-on-epas-proposed-methane-ru