Reliance
ENERGY

VIA ELECTRONIC FILING

December 4, 2015

U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460
Attention: Docket ID Nos. EPA-HQ-OAR-2010-0505; EPA–HQ–OAR–2013–0685; EPA-HQ-OAR-2015-0216

Re: Docket ID Nos. EPA-HQ-OAR-2010-0505; EPA–HQ–OAR–2013–0685; EPA-HQ-OAR-2015-0216

To Whom It May Concern:

Reliance Energy, Inc. ("Reliance") is pleased to provide comment on the proposed rulemakings. Reliance is a small upstream entity that operates primarily in the Northern Midland Basin in the Permian Basin. We are based in Midland, Texas and operate in Texas, New Mexico, and Arkansas. We currently have about 90 employees and operate around 400 wells. We submit this comment with respect to several proposals issued by the U.S. Environmental Protection Agency ("EPA"): (1) The proposed Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, Docket No. EPA–HQ–OAR–2010–0505; FRL–9929–75–OAR, 80 Fed. Reg. 56,593 (Sept. 18, 2015) ("**Methane NSPS**"); (2) The proposed Source Determination for Certain Emission Units in the Oil and Natural Gas Sector, Docket No. EPA–HQ–OAR–2013–0685; FRL–9931–97–OAR, 80 Fed. Reg. 56,579 (Sept. 18, 2015) ("**Source Rule**"); and (3) the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry, Docket No. EPA-HQ-OAR-2015-0216, 80 Fed. Reg. 56,577 (Sept. 18, 2015) ("**CTG**"), collectively, the "Rules."

We write to request that EPA withdraw these Rules because they are unnecessary to protect human health and the environment, and the costs that they will impose on the oil and gas industry are not justified by the minute reduction in global greenhouse gases that could result if the Rules are adopted as proposed. Alternatively, if EPA does not withdraw the Rules, then we ask that EPA (1) clarify and confirm in the final Methane NSPS and CTG that the industry may continue its longstanding practice of using atmospheric tanks to store oil, (2) revise its cost analysis for the Methane NSPS and CTG, (3) exempt small entities (or entities with fewer than a designated threshold of facilities or employees) from the Methane NSPS and CTG; and (4) lessen the burdens associated with the fugitive monitoring regime.

In addition, we request that EPA adopt a more limited definition of the term "source," in the Source Rule, which would only aggregate those activities that are actually physically adjacent to one another. Given the technical complexity and potential economic impact of this proposal, we request that EPA extend the comment period by 60 days to allow the industry to fully digest and respond to the proposal.

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EPA should clarify that well sites subject to these rules may continue to use atmospheric tanks.

Based on both the proposed text of the Methane NSPS, and the current implementation of EPA's Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, codified at 40 C.F.R. Part 60 ("**Subpart OOOO**"), it is our understanding that owners and operators of affected well sites and affected storage vessels can continue the longstanding industry practice of using atmospheric tanks to store oil. We think that the proposed Rules allow sites to continue to use existing atmospheric tanks, and that the industry will be able to add new atmospheric tanks in the future. We believe that this reading is in keeping with EPA's previous requirements under Subpart OOOO and ask that EPA confirm this reading.

At a typical well site, oil, gas, and water flow through a single pipeline from the wellhead to a separator. The separator is essentially a large tank, where gas rises to the top, water sinks to the bottom, and oil fills the middle. From the separator, both oil and water flow into separate storage vessels. These storage vessels, known as "atmospheric tanks" are not pressurized. Instead, they are designed to "breathe" for both safety and practicality purposes. When dissolved gas within the tanks creates pressure, the tanks are designed to allow the gas to be released so that the tanks do not explode or cause other safety hazards. These tanks are commonly used throughout the industry and cost around $10,000 per tank. Many of these storage tanks are already subject to emission reduction controls under Subpart OOOO. For example, based on the requirements in Subpart OOOO, many of Reliance's tanks have been connected to a qualified vapor recovery unit ("VRU"), which reduce the volatile organic compounds ("VOC") and methane emissions from the vessels by 95 percent of designed flash vapors.

If EPA's final Methane NSPS and CTG do not allow for tanks that vent and "breathe" in the way that atmospheric tanks are designed to, then the industry will be forced to replace these atmospheric tanks with pressurized storage vessels at a tremendous cost and with additional safety concerns that are not justified by the minute additional methane reductions that would result. Given the severe economic consequences that replacing these tanks could have on the industry, we ask for EPA to confirm that the Methane NSPS allows for their use.

It is our understanding that under proposed § 60.5365a(e) of the Methane NSPS, new, modified, or reconstructed storage vessels with natural gas emissions below 6 tons per year ("tpy") do not have to meet any additional control requirements, and vapors sent to a VRU do not count towards the vessel's potential to emit ("PTE"). This reading is in keeping with EPA's previous clarification of Subpart OOOO, and we believe that it is the correct reading of the proposed Methane NSPS. However, because this provision could be read in a way that would make it infeasible to use atmospheric tanks, we note that the oil and gas industry has already raised concerns over the ambiguity in the storage vessel requirements with regard to Subpart OOOO, and we incorporate by reference the petitions for reconsideration and clarification of storage vessel requirements filed in response to Subpart OOOO.

In response to those previous concerns, EPA amended Subpart OOOO, including a clarification that the PTE calculation does not include any vapor recovered and routed to a process.[1] Specifically, EPA explained that:

> Our September 28, 2012, letter clarified that the cover and closed-vent requirements must be met when VRU is used to meet the 95 percent reduction emission standards. That said, we previously determined that routing of vapor through a cover and properly operated closed-vent system would recover all vapor routed to the system as long as the VRU is operating (i.e., 95 percent of the vapor being routed to a line when operating for 95 percent of the time). In light of the above, as long as the VRU is operated consistent with those requirements, we believe that it is appropriate to exclude 95 percent of the vapor that would otherwise be emitted if not recovered when determining PTE for purposes of determining affected facility status. As a result of this comment, and based on our prior clarification of this issue, the final amendments to § 60.5365(e) include a provision that "any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status."
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> Further, we have added language to § 60.5365(e) that provides for this adjustment of PTE as long as (1) the storage vessel is operated in compliance with cover requirements in § 60.5411(b) and the closed-vent system ["CVS"] requirements in § 60.5411(c), which has a requirement that the CVS (including the VRU) is operational at least 95 percent of the time, and that the operator maintain records demonstrating compliance with these requirements. We were concerned that, should a VRU be removed or operated inconsistent with the conditions that were the basis for the PTE reduction following the PTE determination for assessing whether the storage vessel is an affected facility, emissions could increase without the storage vessel being subject to control. To address that possibility, we have added language to § 60.5365(e) such that, in the event of removal of apparatus that recovers and routes vapor to a process or operation that is inconsistent with the conditions for qualifying for the PTE reduction, the owner or operator would be required to determine PTE from the storage vessel within 30 days of such removal or operation. If the PTE is determined to be 6 tpy VOC or more, then the storage vessel would be an affected facility and subject to the control requirements in § 60.5395. We believe this approach will help avoid circumvention of the NSPS.

Given both the consistency in text between Subpart OOOO and the Methane NSPS, and EPA's statements in the preamble to the Methane NSPS suggesting that facilities already regulated under Subpart OOOO would not need additional controls to come into compliance with the Methane NSPS, we believe that § 60.5365a(e) of the Methane NSPS is correctly read to allow for the use of atmospheric tanks that comply with the existing Subpart OOOO control requirements.

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[1] EPA, Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards; Final Rule, 78 Fed. Reg. 58,415 (Sept. 23, 2013).

We ask EPA to further clarify that even if a well site is modified and becomes subject to the fugitive-emissions monitoring portions of the Methane NSPS, no existing storage vessel will be required to comply with the new control requirements in the Methane NSPS, unless the existing storage vessel is itself modified or reconstructed as defined by the Methane NSPS; and to confirm that these sets of requirements have independent triggers in the Methane NSPS.

We also ask that EPA clarify that the leak detection and repair requirements for fugitive emissions at well sites and compressor stations will not prevent operators from using atmospheric tanks at these sites. While the proposed Methane NSPS exempts storage vessels with a PTE of less than 6 tpy from the definition of an affected facility for purposes of the storage vessel control rules found at §§ 60.5395a and 60.5397a, the Methane NSPS is unclear as to how these storage vessels with a PTE under 6 tpy will be treated under the fugitive monitoring requirements and how they fit within the definition of "the collection of fugitive emissions components" at a well site or compressor station. Thus, while it appears at first that storage vessels with less than 6 tpy of emissions do not have to meet additional requirements under the Rules, operators may nonetheless find themselves forced to make expensive upgrades to storage vessels in order to come into compliance with the fugitive monitoring requirements unless EPA clarifies the Methane NSPS.[2]

In order to save the industry from unwarranted burdens further detailed below, we ask that EPA clarify that the normal venting of gas from atmospheric tanks is not considered a fugitive emission. The definition of "fugitive emission component" currently exempts "[d]evices that vent as part of normal operations." Atmospheric tanks are designed to vent VOC and methane emissions for both safety and pragmatic reasons. As explained above, these tanks must "breathe" in order to let off excess pressure and prevent the tank from becoming a safety hazard. EPA should clarify that these atmospheric tanks are vented as part of normal operations, and that the venting is therefore exempt from the definition of "fugitive emissions component" in the Methane NSPS.

In addition, these vessels are equipped with openings known as "thief hatches" that are used by operators to measure the volume of oil inside the tank before and after transfers to shipping trucks. These and other openings are also used to check for, or repair potential problems with storage vessels. It is our understanding that the definition of "fugitive emissions component" intends to exempt these practices, so that emissions resulting from opening thief hatches and other openings on storage vessels during these routine operations will not be considered fugitive emissions. The definition explicitly references these openings, but it is our understanding, based on the language in § 60.5411a(b)(2)-(3), that EPA only intends to require operators to equip these openings with proper mechanisms to ensure that the openings are properly seated and sealed when these are not being opened for the reasons enumerated in the regulations.

As we understand the Methane NSPS, well sites can meet the fugitive emissions requirements by ensuring that the seals on thief hatches do not allow for emissions when the hatch is closed. We do not read the Methane NSPS to prevent operators from opening thief hatches and other tank openings. We believe that this reading is in keeping with both the proposed regulatory text and EPA's current method of implementing Subpart OOOO. We would also note that many facilities already subject to Subpart OOOO currently use these same tanks and practices. We ask

[2] *See infra*, discussion of EPA's cost benefit analysis for the Methane NSPS. These costs have not been included in EPA's calculations, and are disproportionate to the emission reductions that they might achieve.

EPA to confirm that this reading is correct, and to add language to the definition of "fugitive emission component" clarifying that opening thief hatches and other openings that are opened for the reasons enumerated in § 60.5411a(b)(2) are considered "[d]evices that vent as part of normal operations" and are thus exempt from the definition of "fugitive emission component." As discussed more thoroughly below, this definition is necessary to prevent excessive burdens on upstream oil and gas operators.

Disallowing the use of atmospheric tanks would lead to significant cost and safety burdens on oil and gas operations.

For storage vessels already in compliance with current Subpart OOOO, or using VRUs as described in the reconsideration to Subpart OOOO to limit their emissions, the incremental gains in emissions reductions from further regulatory controls do not justify the additional expense. EPA has repeatedly recognized that Subpart OOOO had the "co-benefit" of reducing methane emissions from sources subject to Subpart OOOO, and EPA has identified VRUs as the best method of addressing emissions resulting from the normal operations of these tanks.

If EPA's final Methane NSPS and CTG do not allow for tanks that vent and "breathe" in the way that atmospheric tanks are designed to, then the industry will be forced to replace these atmospheric tanks with pressurized storage vessels at a tremendous cost and with additional safety concerns that are not justified by the minute additional methane reductions that would result. According to the Texas Railroad Commission, there are nearly 200,000 regular producing wells in Texas. While the exact number of wells per tank will differ based on multiple factors, it is fair to assume that there is an average of about one tank for every two wells. Most, if not all, of these tanks are currently atmospheric tanks. Based on these estimates, there are nearly 100,000 atmospheric tanks currently in operation in the State of Texas alone.[3] If additional reductions are required from storage tanks beyond those required by Subpart OOOO, members of the industry would be required to replace all of their atmospheric tanks with pressurized tanks, at a cost of approximately $170,000 to replace the standard atmospheric tanks used throughout the industry with pressurized tanks in a single two-tank battery. This would eventually result in an industry-wide cost of $8.5 billion in Texas alone.[4]

These potential costs do not appear to be considered anywhere in EPA's analysis, and would clearly have a significant impact on EPA's final estimation of the value of this proposal. If the final Rules prevent the use of atmospheric tanks, then EPA would need to revise its cost assessment, including its total costs to the industry, costs to small entities, and costs per ton of emissions reductions to include these additional tank costs.

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[3] There are around 149,000 producing leases in the State of Texas. It is also fair to assume that each lease requires its own two-tank battery, and that there are actually closer to 300,000 storage vessels at well sites in the state. We have used the more conservative estimate for purposes of this comment.

[4] While not all of these storage vessels have a PTE of more than 6 tpy, if the emissions from their venting activities are not exempted from the definition of "fugitive emission component," then oil and gas operators would have no choice but to replace these tanks with pressurized tanks in order to comply with the Methane NSPS, as these tanks routinely release some small, but detectable, amount of natural gas emissions during the course of ordinary operations.

Given that only a small percentage of methane emissions are attributable to fugitive emissions from these tanks, such a requirement cannot be justified. EPA itself states in the Methane NSPS that methane emissions from oil and natural gas exploration and production account for only 1.07 percent of U.S. Greenhouse Gas Inventory, and only about 3 percent of total U.S. and 0.3 percent of all global GHG emissions.[5] In the Methane NSPS, EPA estimates that the methane fugitive emissions from a natural gas well site are estimated to be 4.5 tpy, and 1.1 tpy for an oil product well site,[6] and the fugitive emissions from the storage tanks would be only a fraction of those figures. To put these numbers in perspective, a cow releases about 0.12 tpy of methane.[7] As a result, the annual fugitive emissions from a natural gas or oil well site are the equivalent to the methane emissions from 36 and 9 dairy cows, respectively.

In addition, EPA has already acknowledged that methane emissions from the oil and gas sector have been dramatically cut by Subpart OOOO, which allows for the use of atmospheric tanks. When EPA released Subpart OOOO, it estimated that the rule would reduce methane emissions by 1.0 to 1.7 million short tons.[8] Given the extraordinary costs that industry would pay for minute additional reductions in emissions, the resulting rule would be arbitrary and capricious in violation of the Administrative Procedure Act. As a result, we request that EPA clarify that the industry may continue to use non-pressurized atmospheric tanks and to open hatches on these tanks for the purposes outlined at § 60.5411a(b)(2) of the proposed Methane NSPS.

In addition to debilitating compliance costs, requiring further emission reductions from storage tanks would result in unintended safety consequences. Atmospheric tanks cannot sustain the pressure that would result from preventing all natural gas emissions from escaping from the vessels. As a result, operators would have to replace atmospheric tanks with pressurized tanks. While these pressurized tanks may lead to some small reduction in natural gas emissions, they pose a number of safety risks. Gases in high-pressure cylinders contain an extraordinary amount of stored energy. If a cylinder valve is breached (e.g., breaks off when the cylinder falls and strikes a hard surface, etc.), the stored energy in the cylinder is released as thrust. The cylinder can accelerate to speeds great enough to penetrate concrete walls."[9] For example, a failure or blockage of the pressure release valve can cause the tank to become over-pressurized and result in a forceful rupture, which could result in fragments of the tank flying into the air and falling into the vicinity. A sudden release of compressed gas can displace the oxygen in the surrounding area and overcome the workers quickly, without warning. The risk of a failure of the vessel can also be increased due to fatigue from repeated pressurization and depressurization of the fluids inside.

The Occupational Safety & Health Administration ("OSHA") has warned that rupture failures from pressurized vessels can be "much more catastrophic and can cause considerable

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[5] EPA, Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80. Fed Reg. 56,593, 56,608 (September 18, 2018) [hereinafter "Methane NSPS"].
[6] Methane NSPS at 56,635.
[7] UK GHG Inventory Report 1990-2012.
[8] EPA, Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry Fact Sheet 2 (August 16, 2012).
[9] University of Nebraska Lincoln, Safe Operating Procedure: Gases Under Pressure Hazards & Risk Minimization 1 (Jan. 2013), *available at* http://ehs.unl.edu/sop/s-gases_under_pressure_haz_risk_min.pdf.

damage to life and property."[10] As a result, there are a number of OSHA and industry codes and standards that specifically apply to pressurized vessels.[11] We have not seen any indication that EPA has consulted with OSHA to determine whether the Rules might create additional safety hazards to workers, or whether these regulations conflict with existing OSHA regulations or standards. This consultation is critical to ensure the safety of workers at sites that would have to employ these pressurized vessels.

Human errors related to operating pressurized vessels, such as lack of understanding, failure to follow safety operating procedures and lack of functions coordination can have serious consequences. As a result, the addition of pressurized tanks to these well sites would require an overhaul of operating procedures at many of those sites into order to ensure that workers are not exposed to the risks associated with large volumes of pressurized liquids. These compliance and safety overhauls would result in additional costs to the operator that EPA has not yet considered.

There are also dangers associated with removing all gas from the oil before it enters the atmospheric tanks, which would prevent operators from using this as a means of complying with the Rules. There must be positive pressure in the tanks to prevent oxygen from getting into the gas sales line. Oxygen is highly corrosive, and corrosion could lead to other safety and environmental issues such as infrastructure corrosion, which could lead to dangerous gas operating conditions downstream of the well site.

Recommendations: Rather than risk exposing operators to debilitating costs to replace atmospheric tanks, and exposing workers to the safety risks associated with pressurized tanks, EPA should clarify that:

1. Emissions from storage vessels that are sent to a VRU that complies with EPA's regulations are not counted towards a storage vessel's 6 tpy PTE;

2. Emissions resulting from ordinary venting of atmospheric tanks and the activities outlined in § 60.5411a(b)(2) are not considered "fugitive emissions components" and are therefore not subject to the fugitive emissions monitoring rules.

3. Both the storage vessel affected facilities that are in compliance with the control requirements in Subpart OOOO, and the storage vessels that emit less than 6 tpy at affected well sites do not need to install additional equipment in order for the vessels, well sites, or compressor stations to comply with these Rules.

EPA's cost benefit analysis is fundamentally flawed to the point that neither the agency nor the public can actually assess the impacts of the Methane NSPS.

EPA made a number of faulty assumptions in its calculations of the Methane NSPS's costs and benefits. First, EPA estimated the total costs to the oil and gas industry to implement the

[10] Occupational Safety & Health Administration, Pressure Vessels, *available at* https://www.osha.gov/SLTC/pressurevessels/.

[11] *See, e.g.*, Occupational Safety & Health Administration, OSHA Technical Manual: Pressurized Vessel Guidelines, *available at* https://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_3.html.

Methane NSPS. EPA then reduced those costs by the value of the natural gas that EPA estimates that operators will recover from repairing leaks and otherwise complying with the Methane NSPS. EPA asserted that operators would gain revenues of $4/thousand cubic feet (mcf) for this recovered gas.[12] By using this recovered-gas-revenue figure, EPA was able to reduce its calculation of the total annual engineering costs of complying with the Methane NSPS by tens of millions of dollars, from a range of $180 to $200 million in 2020 and $370 to $500 million in 2025, down to $150 to $170 million in 2020 and $320 to $420 million in 2025.[13]

EPA is incorrect in concluding that owners and operators will be able to recover any amount, let alone $4/mcf, for the captured fugitive gases because the amount of gas captured is within the industry margin of error for gas measurement and, therefore, will not be valued in any sale. EPA's cost estimate simply misunderstands the way that natural gas is measured and sold. Orifice meters are the most common and economic measuring equipment used in the industry today. Oil wells typically produce gas at variable rates that create uncertainty in the operating ranges of orifice meters, which increases the margin of error above the perfect condition error of 0.55% inherent to best condition orifice measurement. These differences result in a variance that puts the small volumes per facility anticipated to be captured by compliance with this rule within the error measurement range of the custody transfer equipment. The result of this is that there will be no additional revenue from gas sales generated by compliance with this rule. The EPA's high estimates of 12,000,000 Mcf that might be recovered by compliance with this rule is only 0.04% of the 2014 U.S. gas production. EPA's estimates indicate that gas captured at most exploration and production ("E&P") facilities as a result of the Methane NSPS will fall beneath the meter's margin of error, and, therefore, will not result in any incremental revenue.[14] Even if the industry could generate revenue from the recovered gas, EPA's $4/mcf estimate ignores the current market realities. According to the Henry Hub Natural Gas Futures Quotes, natural gas is currently valued around $2/mcf, and is predicted to stay below $4/mcf until then end of 2024.[15]

By including these "cost savings," which the industry will never actually realize, EPA has skewed its cost analysis and prevented the public from understanding the actual costs associated with this rule. This problem is further exacerbated by the fact that EPA failed to consider the potentially costly equipment upgrades necessary to comply with this rule. As detailed in the discussion of atmospheric tanks, if the Methane NSPS or CTG require operators to replace their atmospheric tanks with pressurized tanks in order to meet fugitive emissions survey requirements, then the industry will eventually bear a far heavier financial burden. EPA has not considered these costs in its analysis, and must either reevaluate its cost analysis or clarify that the ordinary breathing from atmospheric tanks are not "fugitive emissions" under the Rules.

EPA's estimates on the cost of labor for compliance are also wholly unreasonable. The Methane NSPS is a highly complex and technical rule with a number of overlapping requirements. Upstream oil and gas operations frequently fall beneath the air emissions thresholds for permitting requirements. As a result, this portion of the industry has not historically been subject to similar federal air regulations, and their staff is largely unfamiliar with the monitoring, reporting, and

[12] Methane NSPS at 56,596.
[13] *Id.*
[14] *See* Daniel Measurement and Control White Papers, Theoretical Uncertainty of Orifice Flow Measurement (2010).
[15] Henry Hub Natural Gas Futures Quotes (October 28, 2015) *available at* http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

recordkeeping requirements that accompany such rules. This means that these entities will have to expend far more resources either training their own personnel, or hiring personnel with expertise in federal air regulatory matters. This is particularly true for operators in states that already have overlapping state air regulations, as the businesses will need to understand and convey to personnel the differences between the two sets of requirements. For example, the Texas Railroad Commission places limits on the venting or flaring of gas, and Colorado, Wyoming, Ohio, and Pennsylvania have state regulations regarding natural gas emissions and leaks. Differentiating between the requirements from state and federal regimes—particularly when those requirements conflict or overlap—will take additional time and resources.

For most upstream companies, well sites are spread out over a large geographic area. This dispersion of activities across a large geographic area is significantly different from the physical set up of larger facilities, such as natural gas processing plants or refineries, where EPA has imposed these kinds of monitoring requirements in the past. Unlike those larger sites, which have full-time personnel dedicated to one particular facility, most E&P companies assign one employee to multiple small sites. Well sites simply do not have the concentration of activity (including activity that would give rise to air emissions) to justify dedicating a single air compliance employee to each well site. Instead, the air compliance employee will have to spend substantial amounts of time traveling in order to visit each site semi-annually or quarterly, and will then have to keep up with the continual recordkeeping and reporting requirements for each of these small sites. Reliance estimates that operators will need to hire one full-time employee or contractor dedicated to implementing the requirements of the Methane NSPS for every 25 affected well sites operated. Given that there are almost 200,000 producing wells in Texas alone, this means the industry will eventually need to hire thousands of new employees merely to track and fix small equipment leaks.

According to EPA's analysis, "[t]he annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years."[16] Reliance estimates that the actual annual burden imposed by these Rules will be closer to 40-60 hours per affected well site, which will result in an additional cost of $3,500-$5,000 in labor per well site per year. Given that there are hundreds of thousands, if not more than a million, well sites around the nation, these reporting and recordkeeping requirements will eventually balloon into tremendous industry-wide compliance costs.

EPA is also relying on revenue estimates that no longer reflect the reality of the oil and gas market. For oil prices, EPA "estimated revenues using two alternative prices, $70/bbl and $50/bbl. In the results, EPA refers to the case using $70/bbl the 'primary scenario' and the case using the $50/bbl as the 'low oil price scenario.'"[17] In contrast to EPA's estimates, the U.S. Energy Information Administration ("EIA") expects the price of Brent Crude Oil to average $53.96 for the year and the West Texas Intermediate spot average is expected to be $53.57 for the year.[18] Prices have fallen below EPA's "low oil price scenario" of $50/bbl, and many industry experts predict that this trend will continue. For example, Brent crude prices remained below $50/bbl for

[16] RIA at 5-2.

[17] Methane NSPS at 56,658.

[18] U.S. Energy Information Administration, Short Term Energy and Winter Fuels (October 2015).

20 consecutive days in September 2015, and the West Texas Intermediate price fell to $44.74/bbl on October 1, 2015.[19] Goldman Sachs has forecasted that crude prices will average around $45/bbl in 2016, and has even predicted that oil could fall as low as $20/bbl.[20] EPA's cost analysis fails to consider the reality that many industry analysts have repeatedly voiced: lower oil and gas prices are likely to continue for the foreseeable future. EPA should therefore reevaluate its cost estimates based on more realistic revenue figures of the oil and gas sector. As discussed above, natural gas prices are likewise lower than EPA's estimates.

In addition, the model that EPA used to estimate the economic benefits for the reductions in methane emissions associated with this rule is deeply flawed and has not been subject to public notice and comment. In the past, EPA has used a model known as the "social cost of carbon" or "SCC" to place a dollar value on the reduction of carbon dioxide emissions resulting from regulations. This SCC model has come under criticism by those arguing that flaws in the modeling technique and use of discount rates result in inaccurate and inflated estimates of the value of reducing emissions. The SCC model used by EPA has been the subject of Congressional oversight hearings, and is currently under review by the National Academies of Sciences, Engineering, and Medicine.[21] Indeed, some—including Robert Pindyck of the Massachusetts Institute of Technology—have argued that these types of models are so flawed that they are "close to useless as tools for policy analysis."[22] Worse yet, the inclusion of these models "create a perception of knowledge and precision that is illusory, and can fool policy-makers into thinking that the forecasts the models generate have some kind of scientific legitimacy."[23] These models "can be misleading—and are inappropriate—as guides for policy, and yet they have been used by the government to estimate the social cost of carbon (SCC) and evaluate tax and abatement policies."[24] "Because the modeler has so much freedom in choosing functional forms, parameter values, and other inputs, the model can be used to obtain almost any result one desires, and thereby legitimize what is essentially a subjective opinion about climate policy."[25] In fact, EPA acknowledges some of these shortcomings with the SCC model in the Methane NSPS preamble.[26]

While the SCC model used by EPA has many of its own flaws, it has, at least, been used by EPA and other federal agencies for many years, and repeatedly re-evaluated by the Office of Management and Budget ("OMB"). By contrast, the "social cost of methane" model used by EPA to estimate the benefits of methane reductions for the Methane NSPS was developed by an outside

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[19] U.S. Energy Information Administration, Short Term Energy Outlook: Market Prices and Uncertainty Report (October 2015).
[20] *See, e.g.*, Ben Sharples and Grant Smith, *How Low Can Oil Go? Goldman Says $20 a Barrel Is a Possibility*, BloombergBusiness (September 11, 2015), *available at* http://www.bloomberg.com/news/articles/2015-09-11/-20-oil-possible-for-goldman-as-forecasts-cut-on-growing-glut.
[21] *See* House Committee on Natural Resources, Oversight Hearing on "An Analysis of the Obama Administration's Social Cost of Carbon" (July 22, 2015); The National Academies of Sciences Engineering Medicine Board on Environmental Change and Society, Assessing Approaches to Updating the Social Cost of Carbon, *available at* http://sites.nationalacademies.org/DBASSE/BECS/CurrentProjects/DBASSE_167526.
[22] Robert S. Pindyck, The Use and Misuse of Models for Climate Policy, NBER Working Papers 21097, National Bureau of Economic Research, Inc. 2 (April 8, 2015).
[23] *Id.*
[24] *Id.*
[25] *Id.* at 1.
[26] Methane NSPS, 80 Fed. Reg. at 56,654.

organization, has not been vetted for accuracy by the OMB, and has not been subjected to public scrutiny through the notice and comment process. The public has not had the chance to review the accuracy of the inputs or the results of this highly complex climate model, and is therefore unable to meaningfully evaluate the resulting figures that EPA used in its analysis.

EPA also notes in the preamble of the Methane NSPS proposal that the social cost of methane model used to evaluate this rulemaking was the first set of published social cost of methane estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SCC model used by federal agencies.[27] This statement indicates both that social cost of methane model is likely to share many of the same flaws as the SCC model used by EPA, and that methane modeling is still very new and untested. These are two good reasons why EPA should not rely on these models to estimate the benefits of the emission reductions from the Methane NSPS.

This is particularly true when the magnitude of the "benefits" resulting from the use of this model is considered. EPA used this social cost of methane model to calculate an estimated benefit range of $200 to $210 million in 2020 and $460 to $550 million in 2025.[28] These numbers eclipse the total estimated cost ranges associated with the rule of $150 to $170 million in 2020 and $320 to $420 million, and creates the public impression that this costly rule actually has a net economic benefit of hundreds of millions of dollars.[29]

In addition, EPA selected a three percent discount rate to apply to the modeling result associated with this social cost of methane model, while simultaneously applying a much higher (seven percent) discount rate to the costs that the industry will incur.[30] Economists have noted that these models are very sensitive to the discount rate that is applied, which can have huge impacts on the resulting value placed on the reduction of a ton of emissions.[31] As one economist explained, there is no scientific justification for using the monetary values that result from a three percent discount rate for these reductions. Indeed, the federal interagency working group tasked with selecting the SCC model used by the EPA

> did not try to determine the "correct" values for the discount rate. Instead, they used middle of the road assumptions. . . . But other well-known studies have deviated from using these middle of-the-road assumptions and arrived at very different estimates of the SCC. . . . The problem here is that there is no consensus regarding the "correct" discount rate. . . . Because reasonable arguments can be made for a low discount rate or for a high rate, the modeler simply has too much flexibility.[32]

While EPA includes the modeling results and cost estimates at additional discount rates, this information is tucked away in the text of the Methane NSPS and supporting technical documents, while the costs to industry at a seven percent discount rate, and benefits from the model at a three

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[27] *Id.* at 56,655, n.137.
[28] *Id.* at 56,657.
[29] *Id.* at 56,596.
[30] *Id.* By applying a three percent discount rate to the results of the social cost of methane model, EPA concludes that the Methane NSPS has a net benefit of $35 to $42 million in 2020 and $120 to $150 million in 2025.
[31] Pindyck, *supra* note 19 at 1.
[32] *Id.* at 9.

percent discount rate are used to reach the EPA's net-benefit estimate. As a result, the public is unable to fairly compare the costs and benefits associated with this rule.

Recommendations: EPA should reconduct its cost assessment, and do so in a way which:

1. Takes into account the full costs of compliance that the industry will bear, and removes the cost savings which the industry will never recover;

2. Incorporates a more realistic estimate of the amount of time and labor the Methane NSPS will require;

3. Considers the reduced revenue from oil and natural gas under current market conditions; and

4. Removes the comparison to a social cost of methane model that has not yet been reviewed by the Science Advisory Board; National Academies of Sciences, Engineering, and Medicine, or OMB.

The cost associated with these Rules would be particularly onerous for small E&P entities, and EPA has failed to fully consider these impacts.

EPA is required by the Regulatory Flexibility Act[33] ("RFA") and subsequent amendments to determine—to the extent feasible—the Methane NSPS's economic impact on small entities, explore regulatory options for reducing any significant economic impact on a substantial number of such entities, and explain its ultimate choice of regulatory approach.

By EPA's own estimation, 98 percent of the firms in the industries affected by the Methane NSPS are considered small entities.[34] While many members of the public envision giant international conglomerates when they call to mind the oil and gas industry, this figure demonstrates that in reality, the industry is made up of a mosaic of small players, many of whom cannot shoulder the kind of recordkeeping and compliance burden that these Rules would impose. Because the industry is overwhelmingly made up of small entities, the impact of these Rules will be primarily felt by those small businesses. EPA determined that it could not certify that this Rule does not have a significant economic impact on a substantial number of small entities. EPA then convened a Small Business Review Panel and published an Initial Regulatory Flexibility Analysis of the Methane NSPS.[35] This analysis has a number of shortcomings and fails to meet the statutory requirements.

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[33] 5 U.S.C.§ 601 *et seq.*
[34] EPA, Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sectors 2-36 (2015) [hereinafter RIA]. For purposes of the Methane NSPS, EPA defined "small entities" as: "(1) A small business in the oil or natural gas industry whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field." RIA at 5-2, 5-3.
[35] RIA at 1-7.

First, the RFA requires EPA to include "a description of the projected reporting, recordkeeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record."[36] Each initial regulatory flexibility analysis must also contain:

> a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities. Consistent with the stated objectives of applicable statutes, the analysis shall discuss significant alternatives such as —
>
> (1) the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;
>
> (2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;
>
> (3) the use of performance rather than design standards; and
>
> (4) an exemption from coverage of the rule, or any part thereof, for such small entities.

The analysis for the Methane NSPS is wholly inadequate in addressing these issues.

As discussed in the previous section, EPA's projections grossly understate the amount of time and resources that will have to be devoted to the reporting and recordkeeping aspects of this rule. The Methane NSPS is a highly complex and technical rule with a number of overlapping requirements and upstream oil and gas operations in particular are unlikely to be familiar with federal air regulations. This means that these small entities will have to expend far more resources either training their own personnel, or hiring personnel with expertise in federal air regulatory matters than EPA estimated.

Reliance's own experience with these proposed Rules is a good example of what many other small upstream entities are also encountering as they analyze the requirements imposed by the Rules. Reliance has 90 employees. Presently, Reliance has only one employee dedicated full time to regulatory compliance issues, and employs several contract employees to assist with state regulatory compliance requirements. Some other employees spend a portion of their time on regulatory compliance issues, and Reliance estimates that the total man-hours spent on compliance each year is at least the equivalent of about 4 full-time employees. Reliance estimates that it will need to hire at least four additional full-time employees dedicated to complying with the Methane Proposal. In other words, our small entity will have to *double* the man-hours that it devotes to compliance just to meet the requirements of the Methane NSPS. This sharp increase is due in part to the complexity of these Rules, as well as the continual nature of the monitoring, reporting, and recordkeeping requirements associated with the fugitive surveys. Like most other upstream companies, Reliance's well sites are dispersed over a large geographic area, and an employee will

[36] 5 U.S.C. § 603(b)(4).

have to do substantial amounts of travel in order to visit each site semi-annually or quarterly, and will then have to keep up with the continual recordkeeping and reporting requirements for each of these small sites. EPA's analysis and Methane NSPS fail to take into account the resources available to a small entity like Reliance, or to provide a simplified or consolidated method of compliance reporting for small entities. As a result, the analysis does not comply with the RFA.

EPA also failed to consider the devastating financial impact that these Rules could have on small entities. If small entities are required to replace their atmospheric tanks in order to comply with the Methane NSPS, then the cost of those storage vessel replacements could be more than many small businesses can bear, especially in the current economic environment. Even if EPA clarifies that the storage vessels will not need to be replaced, the cost of compliance with fugitive survey requirements will impose a serious burden on small businesses. As discussed above, oil and gas prices have fallen during the past year, and many industry experts expect crude oil prices to remain depressed—around $50/bbl or less. The "break-even" point for the average company that operates in the Midland Basin portion of the Permian Basin, as Reliance does, is around $50/bbl. Estimates suggest that the break-even points for other major shale plays are also above the current market prices for oil. For example, the break-even point has been estimated at $65/bbl for the Eagle Ford and at $68/bbl for the Bakken.[37] Increased compliance costs will raise these break-even amounts further and make it difficult, if not impossible, for small entities like Reliance to stay competitive in current market conditions.

EPA estimates that the annual cost of compliance will be less than two percent of the revenue for the oil and gas industry per year, but did so based on outdated data that suggests far higher revenue for the oil and gas industry than current market rates. As a result, EPA has underestimated the degree to which these Rules will impact revenues. EPA's estimate also ignores the fact that these costs will be disproportionately felt by upstream oil and gas businesses, which tend to be some of the smallest players in the industry. For example, if E&P companies were required to replace atmospheric tanks with pressurized tanks, estimates of the costs for a single onshore facility would increase by $200,000, which translates into a fifty to one hundred percent capital cost increase for the tanks alone.

Even if EPA's estimate were accurate, a two percent cut in revenues is a meaningful decrease for small entities and, under current market conditions, could result in reduced operators, limit employee hours, and even lay-offs. These are the exact types of measures that will stretch small entities even thinner, and are, therefore, more likely to hinder, rather than help, efforts to improve environmental oversight. While EPA may view the impact of each of its regulatory programs in a vacuum, the reality for the entities that EPA regulates is that they have to find a way to comply with *all* of the rules that EPA creates. Two percent here, and two percent there may not sound like much in the abstract, but these compliance costs quickly add up and can quickly make it impossible for businesses to operate profitably.

By hindering the profitability of U.S. oil and gas companies, these Rules will not lead to the decrease in global greenhouse gas emissions that EPA hopes to achieve. EPA has noted that climate change is not a localized problem, and that greenhouse gases disperse globally. Likewise, the oil market is global. These Rules will create a market advantage for our competitors abroad,

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[37] ITG Investment Research, Lower 48 Plays – Pre-Tax PV-10% Break-Even Oil Prices (April 22, 2013).

who are not subject to the same level of environmental regulations, and who have not taken the same voluntary steps to limit emissions. EPA's rules may, therefore, exacerbate the very problem that they are trying to solve by encouraging a greater percentage of oil and gas activities to occur in foreign jurisdictions with no limits on methane emissions.

EPA's analysis also does not establish differing compliance or reporting requirements or timetables that take into account the resources available to small entities. EPA has attempted to take into account the fact that small E&P entities are more likely to drill smaller wells, which will produce fewer barrels per day than the wells drilled by bigger entities. While EPA provides an exemption for fugitive monitoring requirements for well sites that average below 15 barrels of oil equivalent per day ("boepd"), this exemption will not provide any actual relief to small entities. First, it would be difficult, if not impossible, for a well site averaging below 15 boepd to be profitable. As a result, few, if any, small entities will attempt to operate new well sites that average 15 boepd.

In addition, small entities are unlikely to know their actual average boepd until after they have already expended the resources to complete those wells. This after-the-fact exemption is little help for companies like Reliance, because they must estimate their compliance costs at the outset of the project to determine whether it is economically feasible to drill, fracture, or refracture a well. Given the short timeframe that EPA gives these entities to perform fugitive monitoring after a start-up or modification, small entities must make decisions about whether to hire additional personnel, or invest in Optical Gas Imaging ("OGI") cameras, before drilling or modifying a well site. As a result, this exemption for low-producing wells does not provide relief for small entities, and demonstrates a misunderstanding of the upstream industry. Small entities will have to spend the capital to comply with these rules before they are in a position to determine whether compliance is even required. Instead, EPA should provide an exemption either for all small entities, or based on the total number of affected wells at a particular well site to provide greater clarity and certainty to small entities when they make a decision about whether or not to drill a new well, or fracture or refracture an existing well.

The costs associated with these Rules will be particularly devastating to these small businesses, because the costs primarily take the form of up-front capital costs that they must expend when they begin drilling a new well or refracturing an existing well, and before the well is generating any revenue for the company. The need for additional up-front capital can hurt a small entity's ability to borrow money on favorable terms, which can in turn impact whether or not a particular project is actually profitable. Small entities need to procure the capital for these projects from outside sources, and the need to borrow additional amounts, before knowing how profitable a particular well will be, will inhibit the ability of these small entities to borrow on terms that make it economically feasible to pursue these projects. These added expenses will create serious barriers to entry for smaller players in the oil and gas industry. Because these smaller players are often the source of significant innovations, this will prevent the introduction and development of new engineering methods, operating techniques and technologies, including environmentally beneficial innovations.

EPA has also failed to consider the impact that the short time periods included in the rule will have on small entities. As previously discussed, these entities have many small well or compressor sites spread out over large geographic areas. The Methane NSPS creates an endless cycle of tight compliance deadlines that will strain the resources of small entities: first the operators must complete fugitive emissions surveys within 30 days of start-up or modification, then semi-annual or even quarterly surveys, followed by repairs within 15 days of the survey, followed by a follow-up survey within 15 days of the repair. The affected small businesses will have to repeat these requirements at each of their dispersed sites, as well as the recordkeeping and reporting requirements. EPA should have considered the impact that these tight timelines place on small entities and offered extended timelines for those entities.

EPA also did not consider the use of performance, rather than design, standards for fugitive emissions monitoring. The Methane NSPS requires fugitive emissions surveys to be performed with OGI technology. However, as discussed more thoroughly below, OGI cameras are expensive and are only one of a multitude of ways that leaks can be detected. By selecting a single form of expensive technology for detection, the Methane NSPS would require these entities to either invest in purchasing their own cameras and training personnel to use them, or hiring trained contractors to travel to their remote sites. Instead, EPA should allow small entities to demonstrate that they have company-wide compliance plans in place that detect and address leaks through a variety of means best suited to their particular sites. For small entities in states that already require monitoring and leak repair, EPA should allow compliance with those state programs to create a presumption of compliance with the Methane NSPS to ease the burden on operators.

Finally, using a percentage of components, rather than a set number of components, to determine the frequency of surveys is also unfair to small entities. A small site will have fewer fugitive emission components than a larger site. As a result, each leaking component will represent a greater share of the total number of components. While a site with 5,000 components can afford to have 50 leaks without any impact on the frequency of its survey requirements, 50 leaks at a much smaller site with only 1,000 components would trigger more frequent survey requirements under the Rules. Smaller entities are much more likely to operate these smaller sites, and thus are more likely to face more frequent survey requirements under the percentage-based system. Smaller entities are, therefore, more likely to have additional survey requirements, despite the fact that there is no reason to believe that 50 leaking components at a small site have a more meaningful impact on emissions than 50 leaks at a larger site.

Recommendations: EPA should revise its regulatory impact statement to consider the financial impact on small businesses. EPA should consider:

1. Exempting small entities; or

2. Alternatively, EPA should consider exempting well sites with less than four affected wells;

3. Giving small entities 60 days from start-up or modification to perform an initial survey, and 30 days for repairs and follow up surveys;

4. Allowing small entities to use alternative, performance-based methods to demonstrate they are monitoring and repairing natural gas leaks in a timely manner; and

5. Allowing compliance with state leak detection and repair programs to create a presumption of compliance with the Methane NSPS; or

6. Alternatively, only requiring surveys to be performed annually unless two or more consecutive surveys reveal leaks in more than 50 of the fugitive emission components at a well site or compressor station, in which case surveys should be performed semi-annually.

The fugitive emission surveys are impractical and unnecessary for facilities that have instituted the emission controls required under Subpart OOOO or OOOOa, and the definition of "fugitive emissions component" is too vague.

The new controls required under Subpart OOOO and the Methane NSPS already address the primary sources of methane emissions from equipment in the oil and gas sector. Given the anticipated volume of reductions that will be achieved by the new control rules, the fugitive emission monitoring surveys are unnecessary. As previously noted, the fugitive emissions from the well sites and compressor sites are a relatively small portion of the total domestic greenhouse gas emissions. The small leaks that these Rules would require operators to monitor and repair make up an even more minuscule percentage of the emissions from those sites, and do not warrant the amount of resources that would have to be devoted to constantly checking and repairing possible leaks.

The Rules also focus far too many resources on correcting minor leaks. Instead of concentrating on large leaks, which are more meaningful contributors to emissions, the Rules would force companies to devote vast amounts of resources to continuously checking for small leaks that have a negligible impact on emissions. Large leaks are bad for business, and the industry has already found cost-effective ways to catch those leaks, including through voluntary programs such as the Natural Gas STAR Methane Challenge Program. As previously noted, methane emissions from the E&P sector have fallen in recent years despite the tremendous increases in oil and gas production. These declining emissions indicate that the industry has found effective ways to address the sources of these emissions. EPA should continue to encourage these industry-generated improvements, which would be hindered by the fugitive monitoring requirements found in the Rules.

Rather than allowing operators to continue to experiment with methods of finding and repairing leaks, the Rules limit operators to a single form of compliance: OGI technology. In addition, EPA's strict timelines for detection and repair also leave operators with little flexibility to develop a compliance plan that works best for their facilities and will stymie voluntary industry innovations to address methane leaks. In addition, the Rules require operators to focus time and resources on paperwork, rather than developing new solutions, by imposing continuous reporting and recordkeeping requirements.

Many larger leaks can be discovered without using special equipment through visual, auditory, or olfactory inspection. These simple and effective detection methods allow the industry to address the large leaks with which EPA should be most concerned about, without imposing the same burdens as the Rules. Unlike the industry's methods of detecting large leaks, the Rules set an unreasonably low threshold for the types of leaks that must be found and fixed. The Methane NSPS defines a fugitive emission as anything that can be seen using OGI technology, and mandates that all sources of those emissions must be repaired within 15 days. OGI cameras are able to detect leaks at levels that are not environmentally meaningful, and do not provide the operator with information about the quantity of emissions. For example, a release of 1000 mcf of natural gas in a given time can read the same on the camera as a release of 10 mcf. Rather than encouraging operators to prioritize large leaks, the Rules do not distinguish between these larger and smaller leaks and require operators to address all visible leaks in exactly the same way and on the same timeline. The Rules also require the exact same reporting and recordkeeping requirements on leaks of all sizes. Indeed, the only distinction that the Rules make is based on the *number* of leaking components, rather than the *quantity* of emissions from the leaks. By setting the frequency of surveys based on the percentage of leaking components, operators are incentivized to correct multiple small leaks before fixing one large leak.

OGI cameras can be easily manipulated. For example, by adjusting the settings, an operator can make it more or less likely that the resulting image displays emissions. Even if EPA were able to control the process in a way that avoided such manipulation, the results are still highly dependent on the weather conditions at the time the camera is used, and variations in thermal activity could produce false evidence of a violation. OGI cameras can also generate false-positives, and simple changes in temperature can appear as fugitive emissions. These false positives could force operators to perform additional surveys, or make unnecessary repairs to correct non-existent leaks. By imposing nebulous restrictions on the weather conditions under which these surveys can be performed, EPA only further burdens the operators. As previously explained, well sites and compressor stations tend to be located in remote areas that are geographically distant from other facilities operated by the same company. As a result, personnel in charge of air compliance issues are not on-site at every well site or compressor station every day. If weather conditions necessitated rescheduling surveys at one or multiple well sites or compressor stations, the operator could find itself hard pressed to comply with the tight deadlines. In sum, the use of OGI technology creates a number of new problems for operators without creating a meaningful reduction in emissions.

If EPA does not allow operators to use alternative methods to detect and repair leaks, Reliance requests that EPA remove the requirement that operators keep, and make publically available, the images resulting from these surveys. This requirement places unnecessary recordkeeping burdens on operators and has no legitimate compliance purpose. Instead, these images—which EPA proposes to make publicly available—would have a prejudicial impact on the public's perception of oil and gas operations and would unfairly open up operators to litigation challenges. The methane gases are detected and made visual by these OGI cameras at levels that are not harmful to humans. However, the images of escaping fugitive gases from the videos look like frightening clouds of pollutants and create an unjustified fear of danger to human health and the environment in the public's imagination. Preserving and releasing these images will do little but create unnecessary worries and misperceptions about oil and gas operations. EPA's proposal would only assist groups interested in engaging in fear mongering to use these images to whip up opposition to oil and gas operations.

In addition, there is too much ambiguity surrounding what qualifies as a "fugitive emissions component" under the Methane NSPS. As a result, there is a significant risk that operators will unintentionally leave "components" out of their surveys, only to find out later that they are out of compliance as a result. Without a clearer definition of "fugitive emission component," well site or compressor station operators cannot be certain that they have actually included all of the "components" in a survey, and thus made all of the necessary repairs after a survey. The Methane NSPS also adjusts the frequency of survey requirements from semi-annually to annually, or from semi-annually to quarterly, based on the percentage of components found to be leaking during two consecutive surveys.

This method of determining survey frequency is problematic. First, without being able to accurately count the number of components at the well site or compressor station, an operator cannot be certain what percentage of their components are leaking, and thus whether their survey leak detection timeline should be adjusted. This is particularly problematic given the very small margin of error before the survey times adjust: An operator will have different survey frequencies depending on whether less than one, two, or just over three percent of their components are leaking. Yet, how can they determine what percentage of their components are leaking if they cannot accurately establish the number of components at the well site or compressor station? This problem is further exacerbated by the fact that some equipment at these sites is excluded from the definition of "fugitive emissions component" because it is equipment that emits natural gas as part of normal operations. Without greater clarity in the definition, operators may be uncertain how to classify certain equipment, and may unintentionally miscount their components.

Finally, Reliance agrees with EPA that additional rules should not be imposed on liquid loading and unloading operations as there is currently no feasible method to limit VOC and methane emissions during these activities, and there is no evidence indicating that current practices pose a risk to the environment.

Recommendations:

1. EPA should exempt operators from the fugitive survey requirements in the Methane NSPS if they are in compliance with the equipment control requirements in Subpart OOOO or Subpart OOOOa, and have a performance-based internal company program designed to detect leaks annually and repair the leak within 30 days of detection.

2. Alternatively, the Rules should provide 30 days for resurveys to be performed after repairs.

3. EPA should clarify the definition of "fugitive emissions component" and should provide enforcement safe harbors during the first two years of implementation to protect operators who unwittingly miscount their components.

The proposed rule's definition of "modification" for fugitive emissions surveys at well sites and compressor stations is overly broad.

Under the Clean Air Act, the NSPS regulatory program is intended to regulate only *new, modified, or reconstructed* facilities. It is not intended to regulate *existing* facilities. By using this expansive definition of "modification" and "fugitive emissions components," the proposed Methane NSPS undermines that important statutory distinction.

The definition of "modification" of a well site under the proposed Methane NSPS in § 60.5365a(i) is overly broad because it would unnecessarily bring many existing well sites under the Rule's requirements. Under the proposed Methane NSPS, adding a single well to a network of existing wells, or hydraulically refracturing an existing well are considered "modifications" that could trigger fugitive leak detection and repair requirements. This definition is overly broad, as these are not activities that meaningfully increase the likelihood that any other equipment at the well site will leak. Single wells are frequently added to a production facility consisting of a network of existing wells. Similarly, a well may be hydraulically fractured or refractured without making meaningful changes to the existing equipment. Because there is no meaningful change in the equipment, it is unlikely that these "modifications" would have any real impact on the likelihood that that equipment would leak. As a result, this expansive definition would require operators to perform time-consuming surveys on existing equipment at a number of sites without any evidence that the existing equipment had become more likely to leak.

In the midstream context, EPA's proposed definitions of "modification" at 60.5365a(j) is likewise overly broad because it would trigger fugitive emissions monitoring at a compressor station any time that a physical change is made that would increase the compression capacity of the station. The definition would trigger the NSPS requirements in a variety of scenarios where methane and VOC emissions were not actually increased from the station. For example, many components at older compressor stations cannot be replaced with exactly identical equipment, because the equipment is no longer available. Instead, the replacement may have slightly greater horsepower than the previous version. This is a physical change that would technically increase the "compression capacity" of the station, but would not result in additional emissions, because the station would continue to operate as before. Moreover, there is no reason to think that these changes would make the compressor station more likely to have the kind of equipment leaks that the fugitive emissions rules in the Methane NSPS are designed to prevent. As a result, this definition does not serve its intended purpose of preventing emissions from leaking equipment.

Neither definition is in keeping with how EPA has defined "modifications" in the past. Under EPA's general provisions for its air programs, "modifications" are physical changes to a facility that result in an increase in the emission rate to the atmosphere of the regulated pollutant.[38] In other words, this definition explicitly limits "modifications" to those changes that result in greater emissions. EPA's proposed definitions of "modification" at § 60.5365a(i) and § 60.5365a(j) do not contain a similar limitation. Instead, these overly broad definitions encompass *all* changes, even those which will have no impact on, or even result in a reduction in, VOC or methane emissions. For example, in some cases when a new well is added to a well site, the operator will also add a vapor recover tower, which would reduce the overall emissions from the site. Any additions to a well site or compressor station that do not result in greater VOC or methane emissions should not trigger the requirements in these Rules.

In addition, most compressor stations already operate under air permits, which limit their levels of emissions. As a result, even an increase in "compression capacity" would not result in an increase in emissions above permitted levels. EPA has recognized that air emissions that are limited by permitting requirements should be treated differently when considering a facility's PTE. For example, in the New Source Review ("NSR") program, a major source of air emissions may be treated as a synthetic minor source if the actual emissions of the source are limited by the facility's operations to below the major source emissions threshold.[39] EPA's definition of "modification" should take into account legal restrains on a facility's PTE, such as permit restrictions, rather than consider every change in compression capacity to be a "modification." The definition of "modification" for compressor stations is also too vague, as a number of small

[38] *See* 40 C.F.R. § 60.14.
[39] *See* 40 C.F.R. § 49.158.

changes to a compressor station could inadvertently result in greater "compression capacity" without resulting in additional emissions.

Finally, EPA has undermined the framework of the NSPS program and the Administrative Procedure Act by applying the Methane NSPS to all facilities that are built, modified, or reconstructed after September 18, 2015. As noted above, the NSPS program is designed to address *new* rather than *existing* sources. "New" means "new – *after* a regulation is issued". Otherwise, EPA could regulate all existing sources under the NSPS program, because all sources were new at some point in time. By using the date that the proposed Methane NSPS was published in the Federal Register, rather than the date that the final Methane NSPS is published, EPA has ignored this important constraint on the limits of the NSPS program. Using the date of publication of the proposed, rather than final rule, also undermines the public notice and comment required by the Administrative Procedure Act by effectively telling businesses that their comments will be ignored and that they have no choice but to comply with the rule as proposed. In order for the public to be able to meaningfully comment on a proposal, the proposal cannot begin triggering regulatory requirements before the public has had an opportunity to comment on those requirements.

Recommendations:

1. EPA should redefine "modification" in §§ 60.5365a(i) and 60.5365a(j) to only include activities which EPA can demonstrate increase the likelihood that a site will have additional VOC or methane fugitive emissions.

2. Alternatively, EPA should revise its definition of "modification" at § 60.5365a(i)(3) so that the addition of a well, or fracturing or refracturing of an existing well, only triggers fugitive emission survey requirements if the new or modified well expands the capacity of the well site beyond the original facility throughput design.

3. EPA should revise its definition of "modification" at § 60.5365a(j) as "the addition of a compressor at a compressor station that results in an increase of natural gas emissions from the compressor station."

4. Alternatively, EPA should define "modification" at § 60.5365a(j) as "the addition of a compressor at a compressor station or physical changes that result in an increase of natural gas emissions," and explicitly exempt any potential increases in emissions that are otherwise limited by law (such as by a federal or state permit).

5. The final Methane NSPS should only apply to sources built, modified, or reconstructed after the final rule is published in the Federal Register.

The proposed rules are unnecessary and duplicative of existing state and federal requirements, as well as voluntary industry practices.

Emissions are already adequately addressed through state law regimes in most of the major oil and gas producing states. For example, Colorado, Wyoming, Ohio, Pennsylvania, and Texas all have state regulatory requirements designed to limit natural gas emissions from oil and gas operations. These state rules share many of the same goals as the Methane NSPS, but their requirements differ in ways that may make it hard or impossible for operators in those states to comply with both sets of rules. For example, in Colorado the frequency of inspections for well production facilities and compressor stations differ based on their actual uncontrolled VOC emissions, while the Methane NSPS focuses on the percent of leaking components. Colorado also requires audio, visual, and olfactory inspections, while the Methane NSPS mandates that operators use OGI technology for inspections.[40]

These state regimes are continuing to evolve and find creative solutions best designed to address the unique circumstances in their region. Because each geologic formation and shale play is unique, oil and gas operating practices can look very different across varying regions of the country. There is no one-size-fits-all solution. Reliance believes that EPA's Methane NSPS is unnecessary and should be withdrawn because state regulators are better equipped to address the particular issues in their states. However, if EPA does move forward with this proposal, it should at the very least consult with its state counterparts first to learn from their experiences regulating in this area, and determine if portions of the Methane NSPS are unnecessary, duplicative, or conflict with existing state rules.

This need to coordinate with the states is amplified by the fact that the Methane NSPS intrudes into an area historically regulated by the states and creates duplicative and conflicting regulatory obligations without a commensurate environmental benefit. The Clean Air Act repeatedly recognizes the value of state and federal cooperation and the important role that states play in implementing the Act. Unlike many other air regulations, the Methane NSPS leaves no room for states to exercise regulatory authority over the sources within their borders. Instead, EPA has usurped the state's traditional rule by directly regulating these sites. EPA should be mindful of these concerns, and either withdraw the Methane NSPS or craft a final rule that respects the expertise and traditional role of states in regulating these issues.

EPA should likewise reconsider whether this Methane NSPS is necessary, given existing federal regulations of VOC and greenhouse gas emissions. When EPA released Subpart OOOO, it estimated that the rule would reduce methane emissions by 1.0 to 1.7 million short tons.[41] Given the reductions already achieved under this existing regulation, the proposed Rules are an unnecessary burden on the oil and gas industry that cannot be justified by the additional reductions in emissions that would result. In addition, the monitoring and reporting requirements in the Methane NSPS are duplicative of the regulations found at Subpart W, which require gas production and processing sites and compressor stations at transmission and storage sites to annually monitor for fugitive emissions and to quantify those emissions.[42]

Finally, the Methane NSPS is unnecessary because the oil and gas industry is already effectively addressing methane and VOC emissions through voluntary programs. For example, many industry members have entered into the voluntary Natural Gas STAR Methane Challenge Program, which includes recommendations to repair detected leaks. In fact, EPA's own estimates indicate that methane emissions from the oil and gas sector have been steadily decreasing for more than a decade. The oil and gas sector has reduced emissions by more than 20 million metric tons

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[40] *See* Colorado Regulation 7, 5 Colo. Code Regs. 1001-9, § XVII.F.
[41] EPA, Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry Fact Sheet 2 (August 16, 2012).
[42] *See* RIA at 7-30.

of CO_2 equivalent since 1990, despite the tremendous increases in production that occurred during this same period.[43] The industry is continuing to find innovative and cost-effective ways to reduce emissions, but EPA's proposed regulations would stymie that innovation by forcing every business to comply with a one-size-fits-all approach. Instead of mandating a particular set of requirements, EPA should continue to monitor progress in the oil and gas sector to evaluate whether additional regulations are really necessary, and, if so, what form they should take.

Recommendations:

1. EPA should withdraw the Methane NSPS and allow the industry to continue to address natural gas emissions through best practices.

2. Alternatively, EPA should exempt affected facilities in states with their own state VOC and methane emissions regulations from the requirements in the Methane NSPS.

3. EPA should create a mechanism by which it can review the regimes in individual states and grant exemptions to facilities within those states that are in compliance with state regulations.

4. EPA should consult with its state counterparts to determine ways to ensure that the Methane NSPS is not unnecessarily duplicative of state requirements, and does not create conflicts with existing state requirements.

EPA's decision to make the Methane NSPS apply retroactively to all facilities modified or reconstructed after September 18, 2015, but prior to the issuance of the final rule, raises due process and notice concerns.

The Methane NSPS states that it would apply to any facility that was new, modified, or reconstructed after the proposed Methane NSPS appeared in the Federal Register on September 18, 2015. EPA has introduced new definitions of "modification" for portions of the Methane NSPS, and may further alter those definitions before the rule is finalized. As previously discussed in this comment, those definitions are also problematically broad and vague. This puts members of the oil and gas industry in an unfair situation, as they may inadvertently trigger the requirements in the Methane NSPS by making a "modification" to a facility under a version of the definition that has not yet been finalized or clarified.

Given the potential impact of the Methane NSPS, it is not at all unlikely that EPA will spend substantial time responding to all of the public comments and revising the rule before it is finalized. The final Methane NSPS is also likely to face challenges in court that could further delay the implementation of this rule. Existing facilities frequently require maintenance work and updates to their equipment. Until the Methane NSPS is finalized and completed, operators will not know whether they can make certain alterations to their existing facilities without suddenly triggering the NSPS requirements, and thus cannot plan for the necessary compliance costs and personnel hiring that they will need for their facilities.

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[43] 80 Fed. Reg. 56,606; U.S. Energy Information Administration, U.S. Field Production of Crude Oil; U.S. Energy Information Administration, U.S. Natural Gas Gross Withdrawals.

Recommendation: EPA should only apply the Methane NSPS to facilities that are built, modified, or reconstructed after the effective date of the rule.

By increasing compliance costs on natural gas production and transmission under the current market conditions, EPA could exacerbate grid reliability issues and increase greenhouse gas emissions from the electric generation sector.

Meeting future domestic energy demands will require an ample supply of natural gas. According to the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook 2015, natural gas consumption is expected to increase from "26.9 quadrillion Btu (26.2 Tcf) in 2013 to 30.5 quadrillion Btu (29.7 Tcf) in 2040. The largest share of the growth is for electricity generation in the electric power sector, where demand for natural gas grows from 8.4 quadrillion Btu (8.2 Tcf) in 2013 to 9.6 quadrillion Btu (9.4 Tcf) in 2040."[44] This projection does not take into account EPA's own Clean Power Plan, which will further increase the demand for natural gas by incentivizing electric power generation from natural gas rather than coal.

The fact that EPA recently issued a final rule, known as the Clean Power Plan, to reduce greenhouse gas emissions from existing electric generation units, makes the oil and gas industry's ability to provide large quantities of natural gas at affordable prices even more critical. The Clean Power Plan sets limits on the greenhouse gas emissions that these power plants can emit in each state. One of the three "building blocks" the EPA proposes that states use to craft plans to cut emissions is to increase the use of natural gas combined cycle ("NGCC") units, and decrease the use of fossil-fuel fired steam generation units. This will require increasing the annual utilization rates of NGCC units, on average and within each region, to 75 percent on a net summer capacity basis. Meeting this goal will depend in large part on the ability to delivery natural gas to these units. In many cases this will involve building additional transmission infrastructure to transport the natural gas to the NGCC units.

According to the North American Electric Reliability Corporation,

> The implementation of the [Clean Power Plan] final rule is expected to accelerate an ongoing shift toward greater use of natural-gas-fired generation. Increased dependence on natural gas use will require pipeline capacity, particularly during the winter season when natural gas use for electric power competes with residential heating. Approximately 60 GW of additional gas-fired capacity is estimated to be in service by 2020, and approximately 80 GW by 2030. The additional capacity plus the higher use of gas-fired generation is expected to increase gas demand in the United States from 39 Bcf/d to 50 Bcf/d—an increase of approximately 30 percent. Local and regional pipeline infrastructure will be needed to relieve pipeline constraints and fuel firming for the electric industry.[45]

Moving gas requires midstream operators to build compressor stations as well as lay pipeline. Given the low natural gas prices under current market conditions, the additional burden of these

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[44] EIA, Annual Energy Outlook 2015, DOE/EIA-0383(2015), at 16, available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

[45] North American Electric Reliability Corporation, Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Phase I ix (April 2015).

proposed Rules may deter midstream operators from undertaking such construction. While some segments of the natural gas industry were already subject to control requirements under Subpart OOOO, the Methane NSPS expands these requirements for the first time to the midstream segment, and also adds costly and time consuming fugitive emissions monitoring, reporting, and recordkeeping requirements to both well sites and compressor stations. The Methane NSPS may also deter upstream operators from drilling or refracturing activities necessary to supply natural gas to these units.

A number of groups have already raised concerns about the potential grid reliability issues that could result from the Clean Power Plan, particularly because the renewable energy sources, such as wind and solar power, with which EPA contemplates replacing fossil fuels are not yet, and may never be, available in sufficient quantities to provide for the nation's current electric demands.[46] In addition, many renewables cannot be reliably used to meet electric needs during peak demand times. When power plants are unable to meet the demand, blackouts can occur. As a result, the ability to use natural gas to power these electric generation units will continue to be critical to ensuring a reliable source of electric power. If natural gas is not available to supply power plants, then there may be shortages of electric generation as fossil-fuel fired plants are forced to retire, or states may not be able to meet their emission reductions targets.

EPA has already touted the major reductions in greenhouse gas emissions that it expects to gain from the Clean Power Plan. Indeed, EPA has stated that "[p]ower plants are the largest source of carbon dioxide emissions in the United States, making up roughly one-third of all domestic greenhouse gas emissions" and that "[w]hen the Clean Power Plan is fully in place in 2030, carbon pollution from the power sector will be 32 percent below 2005 levels – or 870 million tons less carbon pollution."[47] These reductions far outweigh the modest 3 percent of domestic greenhouse gas emissions from methane that EPA attributes to the oil and gas sector. EPA would jeopardize the reductions that it hopes to achieve from the Clean Power Plan if it simultaneously imposes costly compliance requirements on natural gas operators. As a result, EPA should not attempt to implement these two sets of regulations at the same time.

Recommendations:

1. EPA should postpone consideration of the Methane NSPS and CTG until after 2025.
2. Alternatively, EPA should remove the fugitive emissions monitoring requirements from the Rules in order to ease the compliance burden on operators.

The Methane NSPS's effective date does not give oil and gas operators sufficient time to make necessary equipment upgrades, hire and train new personnel, and complete the required initial surveys.

The Methane NSPS only gives operators 60 days from the time the final rule is issued to come into compliance with its requirements. If the proposed Methane NSPS is any indication, the final rule will also be lengthy and highly technical. In addition, the Methane NSPS will require

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[46] *See id.*
[47] EPA, FACT SHEET: Clean Power Plan By the Numbers (2015), available at http://www2.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-numbers.

operators to scale up their operations by hiring and training new personnel to complete the fugitive survey monitoring, reporting, and recordkeeping requirements, and to ensure that their equipment complies with the new control rules. Operators will not know until the final rule is released what the exact requirements will be, and therefore cannot plan and prepare to implement the rule until it is issued. Assessing and complying with the new requirements within 60 days will be particularly difficult for small upstream entities, as they are unlikely to have existing personnel with experience in federal air regulations, and will have to assess compliance requirements at many well sites.

In addition, there may be shortages of both the equipment and the trained personnel needed to install the equipment and conduct the fugitive surveys. If many small entities are all simultaneously trying to meet these requirements within a 60-day window, the available staff and contractors with the necessary skills may not be able to service the needs of all of these entities during that time frame. For example, there may not be sufficient personnel trained to properly use OGI technology for surveys, which is particularly problematic given how sensitive the cameras can be to different conditions and settings. It may be particularly hard to find skilled personnel in the remote regions where many well sites and compressor stations are located.

Recommendations:

1. EPA should make the Methane NSPS effective one year after the final rule is issued for all facilities.

2. Alternatively, EPA should extend the effective date for small entities by six months.

As with the Methane NSPS, the CTG should also be withdrawn because they are unnecessary and place unjustified burdens on small businesses in the oil and gas sector. Alternatively, if EPA does finalize the CTG, it should revise the guidance to conform to the recommendations that Reliance has made in this letter regarding the Methane NSPS.

The CTG recommends that states impose many of the same requirements included in the Methane NSPS in their State Implementation Plans for existing sources of VOC emissions in areas that are designated out of attainment with EPA's new ground level ozone standard. For all of the reasons discussed above with regard to the Methane NSPS, EPA should withdraw the CTG, or revise them in accordance with the recommendations we have made regarding the Methane NSPS. The burdens imposed on the oil and gas industry under the Methane NSPS are onerous enough; those burdens are exacerbated when these standards are applied to existing sources in ozone non-attainment areas because they dramatically broaden the scope of the requirements by imposing costly changes on existing equipment and requiring surveys at existing well sites and compressor stations. Oil and gas operators will be hard-pressed to meet the compliance requirements in the Methane NSPS for their new or modified sources; if those requirements were expanded to cover existing equipment and sites, then the costs would be far more than many small entities could bear under current market conditions.

In addition, the CTG creates regulatory uncertainty for operators because EPA has not yet designated which areas of the country are out of attainment with the new ground level ozone standard. Many oil and gas operations are located in remote, rural areas that do not have air monitoring equipment. As a result, many operators do not have data available that they can use to even try to predict whether EPA will designate their areas of operation as non-attainment areas, and they therefore cannot properly plan for the capital expenditures and additional personnel that these rules would require.

Recommendations:

1. As with the Methane NSPS, the CTG should also be withdrawn because it is unnecessary and places unjustified burdens on small businesses in the oil and gas sector.

2. Alternatively, if EPA does finalize the CTG, it should revise the guidance to conform to the recommendations that Reliance has made in this letter regarding the Methane NSPS.

EPA's proposed Source Rule would pose a significant burden on upstream oil and gas operators, and is contrary to the Clean Air Act's statutory scheme.

EPA's Source Rule has the potential to impose significant permitting burdens on both the oil and gas industry and the agency by aggregating oil and gas operations dispersed over large geographic areas into a single "source." Under EPA's permitting regulations, a major source includes all "pollution-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 of common control)."[48] EPA has proposed two definitions of "adjacent," both of which are problematic when applied to the oil and gas sector. The first would consider equipment "adjacent" if it is within a quarter mile of the other "pollution-emitting activities." The second would consider equipment "adjacent" if it is within a quarter mile *or* functionally interrelated to the other "pollution-emitting activities."

As explained below, Reliance believes that EPA's Source Rule does not take into account the nature of oil and gas operations, or the purpose of the Clean Air Act. Rather than trying to fit upstream oil and gas operations into a permitting regime designed to address large concentrations of emissions at a single location, EPA should allow emissions from these small, widely dispersed sites to be addressed through the NSPS and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. Alternatively, EPA should use the spacing requirements for well sites set in state field rules as a guideline for when activities are "adjacent."

For example, the Texas Railroad Commission sets certain requirements for well spacing in Statewide Rule 37, as well as specific field spacing rules for individual oil and gas reservoirs. The default Texas rule for oil wells prevents wells from being drilled within 1,200 feet to any well completed in or drilling to the same horizon on the same tract, and prohibits wells being drilled nearer than 467 feet to any property line, lease line, or subdivision line unless the Texas Railroad Commission grants an exception.[49] EPA should use these lease line field rules from state regulatory agencies as the initial criteria for determining whether two activities are "adjacent." These distances would be an appropriate, easy to measure, and publicly available distance to use because

[48] 40 C.F.R. § 52.21(b)(5); 40 C.F.R. § 51.165(a)(1)(i); 40 C.F.R. § 51.166(b)(5).

[49] 16 Tex. Admin. Code § 3.37(a)(1).

operators already use these spacing distances to separate out their different facilities.[50] If two activities are spaced at or farther apart than these spacing requirements, then there should be a presumption that they are separate sources. While this definition may differ between regions, it would be most in keeping with the U.S. Court of Appeals for the D.C. Circuit Court's longstanding directive that EPA should be guided by the common sense notion of a plant.[51]

EPA's proposed definitions ignore the plain meaning of the word "adjacent." Adjacent means "next to or adjoining something else."[52] It does *not* mean activities that are spread out over a wide area simply because they may be "functionally interrelated" to one another. EPA should limit any aggregation to activities that are actually physically adjacent to one another, rather than using a multi-factored and fact-specific analysis. "Functionally interrelated" should be necessary, but not sufficient, to aggregate multiple pieces of equipment into a single source. In other words, EPA should not consider multiple of pieces equipment a single source unless they are *both* physically adjacent to one another *and* functionally interrelated, as a traditional plant would be.

EPA's proposed definitions are also not in keeping with the Congressional intent underlying the permitting programs in the Clean Air Act. Congress gave EPA authority to regulate specific sources of threshold amounts of air pollutants. By putting these minimum thresholds on EPA's permitting authority, Congress chose not to require permits for *all* sources of air pollutants and to instead focus on single sites that emitted a meaningful amount of air pollutants. By attempting to aggregate different activities and equipment dispersed over large geographic areas, EPA is undermining the statutory scheme envisioned by Congress, and attempting to exercise power over activities that Congress never intended for it to have permitting power over.

EPA repeatedly acknowledges in the proposed Source Rule that oil and gas sources are difficult to aggregate, and it has thus been forced to do so on a case-by-case basis. EPA's struggles are indicative of the fact that this is not an appropriate analysis to use for these widely dispersed oil and gas activities. For example, EPA cites the unique characteristics of the oil and gas industry, such as the fact that mineral rights are frequently separated from surface ownership, the widespread nature of operations, and connections via pipeline that make it more difficult to aggregate activities into a single source. EPA concluded that in other industries the "operations already take place at facilities that more clearly match the common sense notion of a plant."[53]

The definition of a "stationary source" was meant to be used for permitting decisions, and the statutory and regulatory requirements surrounding permitting are designed to focus on a single facility that emits a threshold amount of air pollutants. That simply is not how these upstream and midstream oil and gas facilities operate. Unlike a refinery or an industrial plant, these well sites, compressor stations, and other scattered equipment do not amount to a concentrated grouping of air pollution emission points. As a result, they are not a "source" of air pollution as contemplated by the permitting provisions of the Clean Air Act. EPA should recognize that there are other programs, such as NESHAP and NSPS, which are industry-specific and far better suited for

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[50] *See* 16 Tex. Admin. Code § 3.37.
[51] *See* EPA, Source Determination for Certain Emission Units in the Oil and Natural Gas Sector, 80 Fed. Reg. 56,579, 56,581, 56,584 (September 18, 2015) [hereinafter "Source Rule"]; *Alabama Power v. Costle*, 636 F.2d 323 (D.C. Cir. 1979).
[52] Oxford English Dictionary, Oxford University Press (2015).
[53] Source Rule, 80 Fed. Reg. at 56,586.

addressing air pollution for specific pieces of equipment that are not concentrated together at a specific source. Rather than attempting to fit a square peg in a round hole by fudging the definition of "source," EPA should recognize that some emissions are just not properly handled under the permitting programs.

In addition to these statutory considerations, there are also pragmatic reasons why EPA should not attempt to aggregate these oil and gas sources through an expansive definition of the term "adjacent." Adopting either proposed definition in the Source Rule will tax agency resources and force EPA to make fine-grained distinctions about which activities should be aggregated into a single source. The proposed definitions will also open permitting decisions up to litigation and will require additional time to respond to public comments when major source provisions are triggered and Title V permits are required. These problems will be further compounded if EPA adopts a definition of "adjacent" that incorporates the notion of "functional interrelatedness" beyond physical proximity, as it will force EPA to make case-by-case determinations that will always be open to critique and review.

These same shortcomings will also pose pragmatic concerns for the oil and gas industry. The more activities that can be aggregated together, the more likely it is that those activities will collectively trigger minor or major air permitting requirements. It can already take more than a year to receive a Title V major source permit. This time period is likely to grow if additional facilities need permits, and if EPA is required to make case-by-case assessments of whether the activities are "adjacent" during these permitting decisions. These long delays could be devastating to upstream operations, which usually have contractual obligations to begin drilling operations within a relatively short time period. Unlike federal leases, which allow operators more time between entering into the lease and commencing drilling, many private leases require operators to begin drilling within one year. If these upstream operators were required to secure additional permits to begin construction or operation of the well site, which could take more than a year, then they could lose their leases and thus their ability to drill.

Moreover, oil and gas facilities are already subject to federal and state air pollution requirements that can effectively limit their emissions. Imposing additional permitting requirements will create unnecessary compliance burdens without any meaningful environmental impact. EPA notes in the proposed Source Rule that it believes that the additional emissions controls from new sources under the proposed Methane NSPS make it less likely that major source permitting for oil and gas facilities would result in substantial additional pollution control.[54] The agency should, therefore, use its discretion to determine that these facilities are better dealt with under NESHAP, NSPS, and state regulations, rather than attempting to aggregate these scattered activities into sources that trigger permitting requirements.

In addition, EPA's current definition of "common control" included in how it defines a "source" is too expansive and fails to take into account the significant number of upstream oil and gas operations that are performed under arrangements that involve multiple parties with ownership interests. EPA currently uses a case-by-case evaluation to determine common control, under which factors such as (1) common ownership (including stock ownership), (2) contractual powers over

[54] Source Rule, 80 Fed. Reg. at 56,586.

operations, (3) contracts for services, or (4) support dependency relationships, as indications that activities are under common control.[55] These kinds of relationships are extremely common in upstream oil and gas operations, in part due to the often extended and diversified private ownership of minerals and the way leases are obtained as a consequence. As a result, EPA's Source Rule could potentially aggregate an incredibly broad set of activities into a single source, even when the various activities are controlled by different operators.

Given that the Source Rule was released at the same time as the Methane NSPS and CTG, EPA should also clarify in the preamble to the final rule that the "well site," as defined in the NSPS for methane fugitive emissions, is different from the definition of "source" in the aggregation rule. This will prevent regulatory uncertainty for operators who may take actions that modify one well site, and will clarify that other sites aggregated into the same source for air permitting purposes are not also subject to the Methane NSPS by virtue of that modification.

Recommendations:

1. EPA should withdraw its proposed definition of "adjacent" and instead regulate dispersed equipment in the oil and gas sector through other regulatory programs such as NSPS and NESHAP.

2. Alternatively, EPA should adopt a limited definition of the term "source" for only activities truly adjacent. Rather than using a ¼-mile radius to define "adjacent," EPA should instead look to the spacing requirements for well sites within a field, and the Source Rule should clarify that there is a presumption that activities that occur at or beyond those spacing requirements are not adjacent to one another.

3. Alternatively, EPA should use the default 467 foot spacing requirement found in the Texas regulations, and define "adjacent" to mean activities less than 467 feet from one another.

4. Alternatively, EPA should use particular spacing requirements, which are based on state guidelines and differ by formation, for each particular field, and define "adjacent" to mean activities that occur within less than that spacing requirement.

5. EPA should not adopt the second proposed definition of "adjacent" which would include activities beyond a ¼-mile distance from each other when they are "functionally interrelated."

6. EPA should not allow activities to be "daisy chained" together for purposes of determining whether they are adjacent.

7. EPA should also clarify that the "modification" of one well site (*e.g.* by adding one well to a network) would not be a "modification" of other adjacent well sites aggregated under the same "source" for the purposes of air permitting. This clarification will prevent the Methane NSPS from becoming overly broad.

[55] *See, e.g., In re Wansley Steam F Electric Generating Plant Title V Operating Permit 4911-149-0001-V-02-0*, 2007 WL 7388819 (Feb. 14, 2007).

8. EPA should clarify in the preamble to the final rule that the "well site" as defined in the Methane NSPS for methane fugitive emissions is different from the definition of "source" in the aggregation rule.

EPA should grant a 60-day extension to the comment period for the Rules.

These Rules are highly technical, and it is unlikely that many businesses (and small entities in particular) have had adequate time to digest the requirements included in the Rules and understand the implications for their businesses. This is particularly true given that EPA released all three proposed Rules at the same time, and that these Rules, collectively, represent hundreds of pages of highly technical documents. In order to allow these entities to meaningfully participate in the rulemaking process, EPA should extend the comment period by 60 days.

Finally, we request that you respond to each of the comments in this letter before adoption of any final rule.

Regards,

Denzil R. West
Vice President