UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Oil and Natural Gas Sector: Emission Standards for New and Modified Sources	))))))	**Docket No. EPA-HQ-OAR-2010-0505** *Via email* *December 4, 2015*

We appreciate the opportunity to comment on EPA's proposed Emission Standards for New and Modified Sources ("methane NSPS"), 80 Fed. Reg. 56,593 (Sept. 18, 2015), and submit these comments on behalf of Clean Air Task Force, Earthjustice, Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Appalachian Mountain Club, Center for Biological Diversity, Clean Air Council, Clean Water Action, Earthworks, League of Conservation Voters, National Parks Conservation Association, National Wildlife Federation, and The Wilderness Society (together, "Joint Environmental Commenters").

Executive Summary

Environmental commenters appreciate the opportunity to submit these comments, which are informed by our growing understanding of the urgent need to reduce emissions of methane and other harmful pollutants from the U.S. oil and natural gas sector. Recently, the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) concluded that methane is a much more potent driver of climate change than we understood it to be just a few years ago – with a global warming potential as much as 36 times greater than carbon dioxide (CO_2) over a 100-year time frame, and 87 times greater than CO_2 over a 20-year time frame.

Approximately one-third of the anthropogenic climate change we are experiencing today is attributable to methane and other short-lived climate pollutants, and about thirty percent of the warming we will experience over the next two decades as a result of this year's greenhouse gas emissions will come from methane.[1] Climate scientists are now recognizing that avoiding catastrophic climate change will require *both* a long-term strategy to reduce carbon dioxide emissions *and* near-term action to mitigate methane and similar "accelerants" of climate change. As a recent article in the journal *Science* stated, "The only way to permanently slow warming is through lowering emissions of CO_2. The only way to minimize the peak warming this century is to reduce emissions of CO_2 and [short-lived climate pollutants]."[2]

Reducing emissions from the U.S. oil and gas sector is an indispensable part of such a comprehensive climate strategy. Indeed, oil and gas facilities are the largest industrial source of methane in the United States, accounting for over 7 million tons or approximately thirty percent

[1] Climate Change 2013: The Physical Science Basis, Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (Thomas Stocker et al., eds. 2013), *available at* https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_ALL_FINAL.pdf

[2] J.K. Shoemaker et al., What Role for Short-Lived Climate Pollutants in Mitigation Policy? 342 Science 1323-24 (2013), *available at* http://www-ramanathan.ucsd.edu/files/pr200.pdf

of the nation's total methane emissions.[3] Moreover, recent scientific evidence suggests that this number is far too low, with recent studies documenting emissions that are 50% higher than national inventories would predict, as discussed in more detail below.[4] And frequently, methane from oil and gas facilities is co-emitted together with other harmful pollutants, including ozone precursors such as VOCs and carcinogenic substances such as benzene and other hazardous air pollutants ("HAPs").[5]

EPA has already amassed an extensive technical record supporting its methane proposal, including information on low-cost technologies that are readily available to reduce these emissions. A recent report by ICF International found that a discrete set of key technologies could help to reduce methane emissions by 40% for, on average, just one penny per thousand cubic feet of natural gas produced. Another recent report concluded, based on emission estimates from the GHGI, that proven, low cost technologies could reduce the oil and natural gas sector's methane emissions by 42 to 48 percent, at a cost of $8 to $18 per metric ton CO_2e.[6] These same technologies will likewise reduce smog-forming VOCs and toxic air pollutants like benzene. And because methane is a valuable commodity, reductions in methane emissions often pay for themselves due to increased resource recovery – making methane mitigation a low-cost (and sometimes *negative* cost) proposition.

American companies and workers are ready to build the equipment necessary to enhance recovery of natural gas and minimize emissions of methane and other harmful pollutants. Another recent report found these made-in-America solutions are manufactured by numerous companies across the country—many of them small businesses in places like Texas, Oklahoma, the Mountain West, and the industrial Midwest.[7]

Leading states, including Colorado, Wyoming, and Ohio, have already deployed many of these solutions to help protect the health of their citizens. Indeed, given the cross–cutting benefits associated with reducing methane emissions—safeguarding our climate; protecting our families and communities health; and minimizing the waste of resources—there is broad public support for action to minimize methane emissions from the oil and gas sector. Recent polling found that

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[3] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013* (2015) ("2013 GHGI"), at ES-6, Table ES-2, available at http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf.

[4] *See* section I.B, infra..

[5] Pétron, et al., (2014), *A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin*, J. of Geophysical Research: Atmospheres, **119:11** ("Petron (2014)"), at 6836, 6850, *available at* http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/pdf.

[6] Clean Air Task Force, et al., Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Gas Industry (January 2015) ("Waste Not"), at 8-9, *available at* http://www.catf.us/resources/publications/files/WasteNot.pdf.

[7] Datu Research, The Emerging U.S. Methane Mitigation Industry (October 2014), prepared for EDF, available at https://www.edf.org/sites/default/files/us_methane_mitigation_industry_report.pdf

67 percent of registered voters support EPA's methane standards.[8] And this support is broad and diverse: moms, labor representatives, financial organizations, Latino leaders, religious groups and others have recognized the urgency of this problem.

- "We look forward to seeing the strongest possible methane standard finalized… stand ready to work with you to safeguard clean air and a stable environment for our communities and families, now and in the future."[9] Letter from 18 leading Latino groups and individuals

- "The simple act of keeping natural gas in the system provides a significant opportunity to put American workers squarely at the forefront of developing, manufacturing, and implementing technologies needed to accomplish this, creating high-quality jobs and stimulating local economies,"[10] said D. Michael Langford, President of the Utility Workers Union of America in a BlueGreen Alliance statement.

- "The financial and reputational risks of methane emissions are significant and their impacts on the environment and communities well-documented. The proposed EPA [Oil and Gas Standard] is an important step toward curbing methane and advancing more sustainable practices by energy companies and, importantly, it is consistent with the long-term financial interests of the industry and its investors."[11] Christina Herman, Interfaith Center on Corporate Responsibility in a statement.

- "The EPA's standards are a much needed step toward addressing climate change and answering God's call to be stewards of Creation. The proposed standards will reduce the harmful impact of pollution created by the oil and gas industry."[12] Sally Bingham, president and founder of Interfaith Power & Light.

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[8] American Lung Association, Press Release: American Strongly Favor Limits on Methane and Toxic Air Pollution to Protect Health (Sept. 17, 2015), *available at* http://www.lung.org/about-us/media/press-releases/americans-strongly-favor-methane-limits.html.

[9] Letter from Central California Environmental Justice Network et al., to EPA (Dec. 1, 2015), available at http://www.vocesverdes.org/in-the-news/652/letter-latino-leaders-support-strong-methane-standard.

[10] Blue-Green Alliance, *Statement: Labor, Environmental Leaders Applaud Administration's National Methane Reduction Plan* (Aug. 18, 2015), available at http://www.bluegreenalliance.org/news/latest/statement-labor-environmental-leaders-applaud-administrations-national-methane-reduction-plan

[11] Interfaith Center of Corporate Responsibility, *Investors Unite with Climate Advocates to Support Federal Regs to Cut Methane Emissions* (Dec. 3, 2015), available at http://www.iccr.org/investors-unite-climate-advocates-support-federal-regs-cut-methane-emissions

[12] Interfaith Power & Light, *Press Release*: *Faith Community Supports EPA's Proposed Methane Pollution Standards* (Aug. 18, 2015), available at http://www.interfaithpowerandlight.org/wp-content/uploads/2015/08/Methane-press-release.pdf

- "CalSTRS supports the EPA's efforts to reduce methane emissions from oil and gas production and deliver achievable climate benefits."[13] Anne Sheehan, Director of Corporate Governance at the California State Teachers' Retirement System (CalSTRS).

Accordingly, Environmental Commenters strongly support EPA's proposed standards to address methane emissions from new and modified sources under section 111(b) of the Clean Air Act, and below, briefly summarize our recommendations for strengthening these critical protections.

While these standards are important and needed, we also urge the agency to take comprehensive action to protect all communities across the country from methane pollution associated with existing infrastructure. Over 90 percent of emissions from the oil and natural gas sector come from existing infrastructure and the same low-cost technologies can reduce emissions at these sources. Substantial reductions from existing oil and gas infrastructure are achievable by 2020 and can help protect public health, while catalyzing global leadership to address harmful methane pollution.

Indeed, U.S. commitments have helped to catalyze action in Canada and Mexico, and reducing global oil and gas methane by 40-45 percent globally would achieve benefits on par with eliminating the carbon pollution from about 1,000 coal-fired power plants (equivalent to a 30% cut in CO2 from the world's coal plants) when compared using a 20 year GWP metric.

Leak Detection and Repair

Scope. We respectfully recommend EPA to build from and strengthen the scope of the proposed requirements by:

- Clarifying that LDAR applies to potentially high-emitting gathering facilities that have dehydrators but lack storage tanks and compressors.

- Revising the definition of "fugitive emissions components" to require monitoring of intermittent-bleed pneumatic controllers, which are known to function improperly and produce significant emissions; and

- Removing the 15 barrels of oil equivalent per day (BOE/d) exemption and ensuring monitoring at these sites by calibrating monitoring requirements, as provided for in Colorado's Rule.

Frequency. EPA's proposed semi-annual (or annual) monitoring requirements are insufficiently protective. More frequent monitoring is critical to minimize emissions due to leaks, and we urge EPA to strengthen requirements in the final rule by:

[13] Ceres, *Press Release: Investors Applaud EPA's Methane Emissions Rule* (Aug. 18, 2015), available at http://www.ceres.org/press/press-releases/investors-applaud-epa2019s-methane-emissions-rule

- Adopting a quarterly monitoring schedule at well sites and compressor stations, in light of substantial evidence supporting the cost-effectiveness of quarterly and other more frequent monitoring programs. Alternatively, to calibrate frequency requirements at well sites, EPA could adopt an approach that is tiered based on facility size, similar to Colorado's rule.

- Eliminating provisions allowing operators to adjust frequency based on the percentage of leaking components identified in prior surveys, which are not rationally tied to the emissions performance of a facility.

Modifications. We likewise ask that EPA adopt a protective definition of modifications, including the physical and operational changes that EPA has proposed along with additional activities like certain workovers and addition of equipment, like dehydrators.

Advanced Technologies. Advanced technology is swiftly developing that could allow for enhanced environmental performance and minimization of costs. Accordingly, we urge EPA to finalize a pathway that allows operators or other third parties to use advanced, alternative monitoring technologies if accompanied by a rigorous, transparent demonstration that these technologies secure equivalent or superior emission reductions.

Pneumatic Controllers.

We likewise encourage EPA to build from the standards the agency has proposed by strengthening the scope, control measures, and monitoring requirements applicable to pneumatic controllers. In particular, we recommend EPA

- Apply the pneumatic controller standards to intermittent-bleed as well as continuous-bleed natural gas-driven pneumatic controllers.

- Require operators to use inherently zero-emitting technologies, such as air driven pneumatic controllers or electric controllers, instead of natural gas-driven pneumatic controllers, at oil and gas facilities where electric power is available.

- Require operators to reduce emissions from natural gas driven pneumatic controllers by routing bleed gas to a process, such as a VRU or on-site fuel line, or a control device.

- Require rigorous monitoring of emissions from pneumatic controllers to ensure these devices are operating properly, given substantial recent evidence documenting their propensity for malfunction.

Compressors

Compressor are likewise a potentially significant source of emissions, and we recommend EPA:

- Apply the centrifugal compressor requirements to compressors located at well sites, given more recent data suggesting these emissions are significant.

- Centrifugal Compressors. Require operators to capture emissions from each wet seal degassing system and route back to process, to a pipeline or use it onsite for a beneficial use. Routing emissions to a control device that destroys rather than utilizes these emissions should be permitted only as a last resort.

- Reciprocating Compressors. Require operators to capture emissions from each reciprocating compressor rod packing by using an emissions collection system; or alternatively, to adopt a measurement-based threshold to determine when operators must replace rod-packing systems.

Oil Well Completions

Oil well completions are a significant source of emissions and readily available controls can capture and reduce this pollution. We strongly support EPA's proposal to adopt standards requiring reduced emission completions ("RECs") at oil wells and recommend EPA ensure this standard is rigorously applied by:

- Removing the 300 gas-to-oil ratio exemption, given EPA's proposal to exempt wells where a separator is incapable of functioning, which serves the same purpose. Alternatively, EPA could adopt a standard based on gas production that would address a majority of emissions.

- Ensuring provisions requiring capture and beneficial use of completion emissions are rigorously applied, including a thorough consideration of beneficial use in advance of the four compliance options, 1) route to a gas line or collection system, 2) re-inject, 3) use as on-site fuel, or 4) use for another useful purpose that purchased fuel or raw material would serve.

Liquids Unloading.

EPA has not proposed standards to address liquids unloading emissions, despite the fact that this is a significant source of emissions and technologies are available to reduce (or eliminate) this pollution. Accordingly, we urge EPA to adopt liquids unloading standards, and, in particular,

- Define the regulatory term "modification" to encompass actions operators take to restore production at a well when reservoir pressure drops and liquids unloading becomes necessary.
- Adopt a performance-based threshold, based on the suite of available technologies, that can minimize emissions while only addressing a relatively discrete number of high-emitting wells.

I. Introduction

Global climate change is one of the largest challenges our civilization faces. The science of climate change, the risks it presents to human health and welfare, and the role of anthropogenic greenhouse gas ("GHG") emissions as the prime driver of this phenomenon are irrefutable. Immediate and deep cuts to global GHG emissions are necessary to mitigate the worst effects of climate change, and the United States must take a lead role in this process. For this reason, Joint Environmental Commenters strongly support EPA's decision to propose the first-ever nationwide methane emission standards for new and modified oil and gas infrastructure under section 111(b) of the Clean Air Act ("CAA" or the "Act"), 42 U.S.C. § 7411(b).

A. Methane Emissions from Oil and Gas Sources Are Significant.

Methane is a potent GHG that is a major contributor to climate change. According to EPA's own estimates, domestic man-made methane emissions reached nearly 640 million metric tons (MMT)[14] in 2013 on a CO_2-equivalent (CO_2e) basis, accounting for approximately 9.5 percent of total domestic GHG emissions. Oil and gas sources accounted for approximately 151 MMT CO_2e[15] of methane in that year, about 29 percent of economy-wide methane emissions, and over three percent[16] of all GHG emissions. As noted below, these figures most likely understate the actual impact of domestic methane emissions on our climate system, because they are based on 100-year global warming potentials that do not reflect the near-term potency of methane as a greenhouse gas. Nonetheless, based on Greenhouse Gas Inventory's ("GHGI") totals for 2013, the oil and gas sector is, and will continue to be, the single largest source of anthropogenic methane emissions in the United States. In light of these impacts, EPA's decision to propose new source performance standards ("NSPS") for methane emissions is urgently needed and entirely appropriate.

B. The True Impact and Extent of Methane Emissions for Oil and Gas Sources Are Likely Greater Than EPA's Estimates.

The emissions estimates in the proposal significantly understate methane's true environmental impact for several reasons. First, in both the 2013 GHGI and the RIA for the proposed methane NSPS, EPA relied on the 100-year global warming potential ("GWP")[17] for methane—a value of 25—that appeared in the Intergovernmental Panel on Climate Change's ("IPCC") Fourth Assessment Report ("AR4") from 2007.[18] In 2013, the IPCC released its Fifth Assessment Report ("AR5"), providing its most up-to-date conclusions on the science of climate change.

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[14] 2013 GHGI, at Table ES-2.

[15] *Id.*; *see also* EPA, *Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector*, EPA-452/R-15-002 (Aug. 2015) (hereafter, "RIA"), at 3-1—3-2. As EPA notes in the RIA, this figure (as well as the total methane emission estimates) accounts for 3 MMT from oil well completions that were not included in the 2015 GHGI.

[16] This includes about 44 MMT of direct CO_2 emissions in 2013.

[17] A compound's GWP refers to its ability (in comparison to CO_2) to trap heat from the sun in the Earth's atmosphere. CO_2 has a GWP of 1; a compound *x* with a GWP of (for example) 50 would have 50 times more heat-trapping capacity than the same quantity of CO_2.

[18] *See* RIA at 4-13, n. 35; 2015 GHGI at ES-3.

AR5 revised the earlier report's 100-year GWP for fossil methane from 25 to 36,[19] yet EPA continues to use the lower, outdated figure from AR4. Had the agency instead relied on the most accurate value of 36, its estimate of 100-year climate impacts of methane from oil and gas sources would have been 44% higher - 217 MMT CO_2e rather than 151 MMT.

Second, EPA relies exclusively on the 100-year GWP for methane in its analysis, even though shorter timeframes more accurately capture the climate-forcing impacts of methane emissions. Because methane stays in the atmosphere for an average of 12 years[20] before decaying into CO_2, its impacts are concentrated in the near-term. It is critical to assess those shorter term impacts on the climate system in evaluating methane reduction measures. AR5 reports a 20-year methane GWP of 87,[21] which corresponds to a total of roughly 525 MMT CO_2e from domestic oil and gas methane emissions in 2013 (approximately 348% higher than the 2013 GHGI estimate).

Third, EPA likely underestimates the total amount of methane pollution emitted by the oil and gas sector. The agency's GHGI takes a "bottom-up" approach to quantify sector-wide methane emissions. This involves estimating the average pollution associated with each type of source (*e.g.*, the average annual emissions from each pneumatic controller) in a given year, then multiplying each per-unit emission figure by the total estimated number of units in the sector for each source type (*e.g.*, the total number of pneumatic controllers in the country). This technique contrasts with the "top-down" approach, in which researchers sample atmospheric concentrations of methane in areas with heavy oil and gas development, and then estimate the extent to which oil and gas sources contribute to the measured concentration levels. Comparisons between the GHGI and top-down studies support the conclusion that the GHGI, and other bottom-up estimates, significantly underestimate the methane emissions from oil and natural gas sources.[22] Other top-down analyses support this conclusion. One top-down analysis of emissions of Colorado's Denver-Julesberg Basin estimates an emission rate of 2.6 to 5.6 percent,[23] and another study of Utah's Uinta Basin indicated an emission rate of 6 to 12 percent,[24] as compared to the approximately 1.4 percent assumed in last year's GHGI (representing estimates from 2012).[25] Similarly, a recent study sponsored by the Environmental Defense Fund indicates

[19] IPCC, *Fifth Assessment Report, Climate Change 2013- The Physical Science Basis*, *Chapter 8: Anthropogenic and Natural Radiative Forcing* (Sept. 2013), at 714, Table 8.7, *available at* https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf. Methane's GWP of 36 reflects the full impacts from fossil-based sources and includes impacts from methane's oxidation to carbon dioxide.
[20] *Id.*
[21] *Id.*
[22] Brandt, A.R., et al., (2014), *Methane Leaks from North American Natural Gas Systems*, Science, 343:6172, 733-735, *available at* http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf..
[23] Pétron (2014), at 6836, 6850.
[24] Karion, (2013), *Methane emissions estimate from airborne measurements over a western United States natural gas field*, Geophysical Research Letters, **40:16**, at 4393, *available at* http://onlinelibrary.wiley.com/doi/10.1002/grl.50811/full.
[25] *See* Dep't of Energy, *Fact Sheet: Natural Gas Greenhouse Gas Emissions* (2014), *available at* http://energy.gov/sites/prod/files/2014/07/f18/20140729%20DOE%20Fact%20sheet_Natural%20Gas%20GHG%20Emissions.pdf.

sector-wide emissions 1.5 to 2 times EPA's reported estimates.[26] These analyses support that EPA's bottom-up data significantly underestimates the true extent of methane emissions from oil and gas sources.

Therefore, both the environmental impact of methane emissions from domestic oil and gas sources and the quantity of those emissions likely exceed EPA's estimates in its 2013 GHGI and supporting materials for the proposed rule. The need to regulate these sources is therefore even more urgent than reflected by the agency's own data and analyses.

C. The Proposed Methane NSPS Is Necessary, But Not Sufficient, For the United States to Meet its International Climate Commitments.

President Obama announced in November 2014 a bilateral agreement with President Xi Jinping of China in which the United States committed to a 26-28 percent GHG reduction by 2025, relative to 2005 levels.[27] The President's Climate Action Plan likewise includes a 17 percent reduction from 2005 levels by 2020.[28] To aid in achieving these goals, the Administration committed to cut oil and gas sector methane emissions 40 to 45 percent below 2012 levels by 2025.[29] The proposed NSPS is an important and necessary step—but not nearly sufficient—toward the goal of a 40-45 percent reduction, and accordingly, we urge EPA to move forward with comprehensive standards addressing methane from existing sources in the oil and natural gas sector.

According to EPA's GHGI, oil and gas sources emitted over six million metric tons of methane in 2013.[30] A 40 to 45 percent reduction from this total would require cuts on the order of 2.6 to 3 million metric tons if there is no additional growth in emissions between now and 2025 (an unlikely scenario). In its RIA, EPA estimates that the proposed methane NSPS will reduce

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[26] Lyon, et al., (2015), *Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region*, Environmental Science & Technology, 49:13, at 8147-57, *available at* http://pubs.acs.org/doi/pdf/10.1021/es506359c. *See also* Karion, et al., (2015), Environmental Science & Technology, *Aircraft-Based Estimate of Total Methane Emissions from the Barnett Shale Region*, Environmental Science & Technology, 49:13, at 8124-31, *available at* http://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00217.

[27] Press Release, The White House, U.S.-China Joint Announcement on Climate Change (Nov. 11, 2014), *available at* https://www.whitehouse.gov/the-press-office/2014/11/11/us-china-joint-announcement-climate-change.

[28] Executive Office of the President, *The President's Climate Action Plan* (June 2013), at 4, *available at* https://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

[29] Press Release, The White House, Fact Sheet: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

[30] 2013 GHGI, at 3-3, Table 3-2. The 2013 GHGI estimate for oil and gas sources is about 151 million metric tons of methane on a CO_2e basis. The 2013 GHGI estimates 157.4 MMT of CO_2e from methane emissions from the oil and gas sector, but this includes emissions from certain distribution sources that are not addressed in EPA's proposal and does not include the 3 MMT CO_2e from oil well completions that EPA estimates in the proposal. 80 Fed. Reg. at 56,607.

sector-wide emissions by between 340,000 and 400,000 short tons in 2025 (308,000 to 363,000 metric tons).[31] While other regulatory efforts—particularly the 2012 VOC-based NSPS—will provide additional reductions, it is clear that EPA must not only finalize strong methane rules for new sources, but must expeditiously move forward with existing sources to protect the public health and welfare of all Americans; satisfy its international commitments; and help avert the worst impacts of climate change.

II. Legal Overview of Section 111 of the Clean Air Act

Section 111 of the Clean Air Act ("CAA" or "the Act") requires EPA to set standards of performance for stationary sources of air pollution that reflect the "best system of emission reduction," taking into account cost and other factors. *See* 42 U.S.C. § 7411. Under section 111(b), the Administrator is tasked with setting federal standards of performance for all new, modified, and reconstructed sources in a category of sources that, in the Administrator's judgment, "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." *Id.* § 7411(b)(1), (a)(2); 40 C.F.R. § 60.15. These are commonly known as new source performance standards, or NSPS.

When the NSPS for a source category cover a pollutant that is neither subject to National Ambient Air Quality Standards ("NAAQS") nor regulated for that source category under the hazardous air pollutant provisions in section 112, section 111(d) also requires the Administrator to prescribe emission guidelines for the existing sources in that source category. *Id.* § 7411(d); 40 C.F.R. § 60.22(a). Because standards under section 111 apply nationwide, they help to prevent new air pollution problems as well as prevent existing problems from worsening. These goals are particularly important with respect to the oil and natural gas source category, which is responsible for substantial existing air pollution problems and is the single largest emitter of anthropogenic methane in the nation.[32]

A. *New Source Performance Standards Under Section 111(b) Must Reflect the Rigorous* Technology-Forcing Approach that Congress Intended.

EPA's standards of performance under section 111(b) must

> reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact

[31] RIA at 4-545, Table 4-2.

[32] The emission limits established by the standard must be met by sources within listed categories that commence construction or undergo modification after the date of the *proposal* of such standard. *See* 42 U.S.C. §§ 7411(a)(2) (a "new source" is "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance"). Any new source within a listed category that begins construction, or any existing source that receives, or should receive, a permit to undergo a modification under Section 111 after the published date of the proposal for the standard must therefore comply with the standard EPA promulgates in the final rule.

> and energy requirements) the Administrator determines has been adequately demonstrated.

42 U.S.C. § 7411(a)(1). Courts have recognized this "best system of emission reduction" ("BSER") standard is designed to "enhance air quality and not merely to maintain it" by "forcing all newly constructed or modified [facilities] to employ pollutant control systems" that will reflect the best demonstrated system of reduction." *ASARCO Inc. v. EPA*, 578 F.2d 319, 322 & 322 n.6 (D.C. Cir. 1978); *see also Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785-86 (D.C. Cir. 1976) (discussing these standards).

Section 111(b) establishes a technology-forcing program for new sources. Congress's intent was "to induce, to stimulate, and to augment the innovative character of industry in reaching for more effective, less costly systems to control air pollution." *Sierra Club v. Costle*, 657 F.2d 298, 347 n.174 (D.C. Cir. 1981) (quoting legislative history). As the D.C. Circuit has explained, "[s]ection 111 looks toward what may fairly be projected for the regulated future, rather the state of the art at present, since it is addressed to standards for new plants." *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C.Cir.1973) ("*Portland Cement I*"); *see also Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999).

Furthermore:

> An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming *exorbitantly costly* in an economic or environmental way.

Essex Chemical Corp. v. Ruckelshaus, 486 F.2d 427, 433 (D.C. Cir. 1973) (emphasis added). From an economic standpoint, EPA need only ensure that the cost of new source control is not "greater than the industry could bear and survive." *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) ("*Portland Cement II"); see also Lignite Energy Council*, 198 F.3d at 933 (EPA may exclude emission controls that would impose "exorbitant" economic or environmental costs). Therefore, EPA must consider whether the industry as a whole – not an individual affected source or company – is able to "adjust itself in a healthy economic fashion" to meet the standards. *Portland Cement II*, 513 F.2d at 508. If it can, EPA's standard satisfies section 111's cost component, regardless of the economic impacts on any specific source or sources.

Where it is "not feasible to prescribe or enforce a standard of performance," EPA must instead "promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction" which is adequately demonstrated. 42 U.S.C. § 7411(h)(1). The Act defines the circumstances in which it is "not feasible" to set a standard of performance, including where "a pollutant or pollutants cannot be emitted through a conveyance" capable of capturing such pollutants or where "the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations." *Id*. § 7411(h)(2).

B. EPA Has Reasonably Determined that Regulation of Methane from the Oil and Gas Sector Is Appropriate Under Section 111.

Section 111 of the Clean Air Act directs EPA to publish, and from time to time revise, a list of categories of stationary sources that, in EPA's judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. 42 U.S.C. § 7411(b)(1)(A). EPA listed oil and gas sources as a source category under section 111 in 1979. Priority List and Additions to the List of Categories of Stationary Sources, 44 Fed. Reg. 49,222, 49,226 (Aug. 21, 1979); 40 C.F.R. § 60.16. Under this source category, EPA first promulgated VOC new source performance standards in 1985, Standards of Performance for New Stationary Sources; Equipment Leaks of VOC From Onshore Natural Gas Processing Plants, 50 Fed. Reg. 26,122 (June 24, 1985), and issued SO_2 new sources performance standards from gas processing plants that same year, Standards of Performance for New Stationary Sources; Onshore Natural Gas Processing SO_2 Emissions, 50 Fed. Reg. 40,158 (Oct. 1, 1985). EPA later revised the standards to address VOC emission from a broader suite of sources. Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 (Aug. 16, 2012). *See* 40 C.F.R. § 60, subpart OOOO.

EPA now proposes new source performance standards for methane emissions from oil and gas equipment in the production, gathering and boosting, processing, and transmission and storage segments.[33] The agency is fully within its legal authority to issue these regulations pursuant to the 1979 listing of the oil and gas industry as a section 111 source category, and no further administrative endangerment finding is necessary.

As noted above, section 111(b)(1)(A) states that the Administrator "shall include" a category of sources in the list for which standards are required "if in [her] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A). The statutory language refers to the category of sources, not to specific pollutants from the category. Section 111(b)(1)(B) then directs the Administrator to "establish . . . Federal standards of performance for new sources within [a listed] category." *Id.* § 7411(b)(1)(B). The endangerment and contribution findings are part of the process of listing a category of sources, not the process of promulgating standards of performance for particular air pollutants emitted by those sources. Therefore, the plain language of the statute makes clear that EPA need not make a pollutant-specific endangerment or contribution determination for methane emissions from sources in the proposed subpart OOOOa.

Moreover, in practice, EPA has never issued a new or revised endangerment finding when revising new source performance standards ("NSPS") under § 111, even when revising the NSPS to add a new pollutant to those regulated in the category or adding a new source to the category. Examples of this practice abound over the course of EPA's time tested experience administering section 111 over several decades. *See, e.g.*, 74 Fed. Reg. 51,950, 51,957 (Oct. 8, 2009) ("The plain language of section 111(b)(1)(A) provides that such findings are to be made for source categories, not for specific pollutants emitted by the source category… Determinations regarding the specific pollutants to be regulated are made, not in the initial endangerment finding, but at the

[33] EPA is also proposing VOC performance standards for all sources covered under the proposed methane rule that were not included in the agency's previous VOC regulations for oil and gas infrastructure.

time the performance standards are promulgated.") (amending subpart Y, which had set PM standards since 1976); 41 Fed. Reg. 3826 (Jan. 26, 1975) (relying on an endangerment finding for one pollutant when setting standards for two pollutants); 77 Fed. Reg. 9304 (Feb. 16, 2012) (amending 71 Fed. Reg. 9866 (Feb. 27, 2006) regarding HAPs emissions from fossil fuel-fired EGUs); 75 Fed. Reg. 54,970 (Sept. 9, 2010) (amending 36 Fed. Reg. 24,876 (Dec. 23, 1971) regarding HAPs emissions from Portland cement plants); 73 Fed. Reg. 35,838 (June 24, 2008) (amending 39 Fed Reg. 9308 (Mar. 8, 1974) regarding petroleum refineries); 70 Fed. Reg. 28,606 (May 18, 2005) (amending 36 Fed.Reg.24,876 (Dec. 23, 1971) regarding steam-generating EGUs); 54 Fed. Reg. 34,008 (Aug. 17, 1989) (amending 39 Fed. Reg. 9308 (Mar. 8, 1974) regarding fluid catalytic cracking unit regenerators); 52 Fed. Reg. 47,826 (Dec. 16, 1987) (amending 51 Fed. Reg. 42,768 (Nov. 25, 1986) regarding commercial-industrial steam generators).

EPA's proposal includes ample information supporting the agency's rational basis for regulating methane from the oil and natural gas sector. Moreover, even if section 111 *did* require an endangerment or cause-or-contribute determination for individual pollutants from a given source category for EPA's regulation of those particular pollutants, the current proposal easily passes legal muster, as it is supported by EPA's 2009 Endangerment Finding; additional information on harmful effects of greenhouse gas emissions included in EPA's methane proposal; as well as information on the contribution of stationary sources in the oil and gas sector to harmful methane pollution.

2009 Endangerment Finding. In *Massachusetts v. EPA*, the Supreme Court held that the CAA authorizes federal regulation of emissions of greenhouse gases and directed EPA to make a science-based determination as to whether greenhouse gases from motor vehicles endanger public health and welfare. 549 U.S. 497, 528-29 (2007). In December 2009, EPA concluded that emissions of six well-mixed greenhouse gases from mobile sources—including methane—"cause or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare." Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009) ("the Endangerment Finding"). The Endangerment Finding was made after an extraordinarily thorough scientific review and careful consideration of public comments. It was reaffirmed after full consideration of petitions for reconsideration and was upheld in its entirety by the D.C. Circuit in the face of a vigorous industry challenge. *Coal. for Responsible Regulation, Inc. v. EPA (CRR I)*, 684 F.3d 102, 116-27 (D.C. Cir. 2012), a*ff'd in part, rev'd in part sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014) *and amended sub nom. Coal. for Responsible Regulation, Inc*. *v. EPA (CRR II)*, 606 F. App'x 6 (D.C. Cir. 2015). The court found that the Endangerment Finding was procedurally sound, consistent with Supreme Court case law, and amply supported by the administrative record, observing that "[t]he body of scientific evidence marshaled by EPA in support of the Endangerment Finding is substantial." *Id.* at 120. And while it granted certiorari on one component of the D.C. Circuit's holding in *CRR I*, the Supreme Court declined to review any aspect of the lower court's holding on the Endangerment Finding. *See Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 418, 2013 U.S. LEXIS 7380 (Oct. 15, 2013).

The 2009 Endangerment Finding fully satisfies any requirement for an endangerment finding under section 111, not only for proposed subpart OOOOa, but for any other listed source category for which EPA may set greenhouse gas standards going forward. EPA made very clear in 2009 that the endangerment component of its finding rule applied generally to the sum total of all anthropogenic greenhouse gas "air pollution," irrespective of the sources from which the individual "air pollutants" were emitted. *See, e.g.*, 74 Fed. Reg. 66,496, 66,506 (Dec. 15, 2009) ("[T]he Administrator is to consider *the cumulative impact* of sources of a pollutant in assessing the risks from air pollution, and is not to look only at the risks attributable to a single source or class of sources." This distinction originates in the CAA itself. Section 202(a)(1) provides that

> [t]he Administrator shall by regulation prescribe (and from time to time revise) in accordance with the provisions of this section, standards applicable to the emission of any *air pollutant* from any class or classes of new motor vehicles or new motor vehicle engines, which in [her] judgment cause, or contribute to, *air pollution* which may reasonably be anticipated to endanger public health or welfare.

42 U.S.C. § 7521(a)(1) (emphasis added). Thus, the statutory provision applied in the 2009 Endangerment Finding required EPA to consider whether "air pollution" may reasonably be anticipated to endanger, not the "pollutant" itself. As EPA explained,

> to help appreciate the distinction between air pollution and air pollutant, the *air pollution* can be thought of as the total, cumulative stock in the atmosphere, while the *air pollutant* can be thought of as the flow that changes the size of the total stock.

74 Fed. Reg. at 66,536 (emphasis in original).

EPA therefore determined in 2009 that the "total, cumulative stock" of GHGs—not just mobile source emissions—could reasonably be anticipated to endanger public health and welfare. And as the Endangerment Finding makes clear, the total, cumulative stock of GHGs includes atmospheric methane resulting from man-made activities. In the Finding, EPA cites methane as the second-largest well-mixed GHG on a CO_2-equivalent basis, after carbon dioxide itself. *Id.* at 66,549. EPA further notes that "[t]he global atmospheric concentration of methane has increased by 149 percent since pre-industrial levels (through 2007)[,] . . . [and] [t]he observed concentration increase in th[is] gas[] can . . . be attributed primarily to anthropogenic emissions." *Id.* at 65,517. In comparison, global concentrations of carbon dioxide have increased by 38 percent since pre-industrial times and nitrous oxide by 23 percent—large increases, to be sure, but several times smaller than the corresponding increase in atmospheric methane. *Id.*

EPA's Proposed Rule and Additional Information. Information from EPA's 2013 GHGI further emphasizes the problem of methane emissions from oil and gas sources in the United States. The GHGI reports domestic methane emissions in 2013 of 636.3 million metric tons CO_2e, second only to CO_2 and approximately 9.5 percent of all domestic GHG emissions from human sources.[34] However, as discussed above, this figure relies on a global warming potential of just 25—the IPCC's 100-year figure from the Fourth Assessment Report.[35] Re-calculating this total using the IPCC's updated 100-year GWP for methane of 34 results in an increase of domestic methane emissions by 865.4 million metric tons CO_2e (12.5 percent of all GHG emissions). Using the updated 20-year GWP of 86—the most appropriate factor, as described above—increases the total to 2,189.9 million metric tons CO_2e, or 26.6 percent of all domestic GHGs in 2013. Together, oil and gas sources are the single largest contributor of methane in the U.S., accounting for nearly 30 percent of domestic emissions according to the GHGI.[36] And, as discussed previously, top-down studies suggest that the true contribution from these sources is considerably higher. Therefore, EPA's findings strongly support the conclusion that methane emissions from oil and gas sources are a major contributor to atmospheric concentrations of well-mixed greenhouse gases. Even if section 111 were interpreted to require that EPA formally find a source category "significantly contributes" to endangering air pollution with respect to each regulated pollutant it emits, the findings in the proposed rule with respect to the large volume of methane emissions from the oil and gas sector would more than satisfy such a requirement.

In short, EPA's 1979 oil and gas category listing provides the agency with all the endangerment determination it needs to proceed with the proposed methane rule. To the extent that EPA must articulate a rational basis for regulating methane emissions from this sector under section 111, the 2009 Endangerment Finding and the agency's current data on the magnitude of methane emissions from this sector are more than sufficient to justify EPA's proposal. No additional endangerment finding—whether source-specific or pollution-specific—is required or needed.

C. EPA Has Authority to Issue Its Proposed Methane Standards Under a New Subpart OOOOa, Regardless of Any Overlap With the 2012 VOC Regulations.

1. EPA Must Issue Methane Standards for All Oil and Gas Sources, Including Those Covered Under the 2012 VOC NSPS.

We support EPA's decision to promulgate its proposed methane standards under part 60, subpart OOOOa. After listing a source category under section 111, EPA is empowered to issue new source performance standards for any pollutant emitted by that source category so long as it has a rational basis for doing so. As noted above, EPA has developed—and the D.C. Circuit has upheld—a voluminous administrative record affirming beyond question that greenhouse gases, including methane, endanger the public health and welfare. The oil and gas industry is the largest source of anthropogenic methane emissions in the United States. The agency's decision to regulate methane emissions from this sector under section 111 is, therefore, wholly rational.

In the VOC rulemaking process, many stakeholders—including Joint Environmental Commenters—urged EPA to issue section 111 standards for methane in addition to VOC, given the severe climate-forcing impacts of this pollutant and the growing problem of methane emissions from the oil and gas industry. EPA determined that it lacked sufficient data on

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[34] 2013 GHGI at Table ES-2.
[35] *Id.* at ES-3.
[36] *Id.* at Table ES-2.

methane emissions from oil and gas sources to proceed with a rulemaking at that time while noting its intention to collect additional data through the Greenhouse Gas Reporting Program. 77 Fed. Reg. 49,490, 49,513-14 (Aug. 16, 2012). EPA now states that it has collected valuable data through the Reporting Program since that program began in September 2012, and that these data confirm that sectorwide emissions are both substantial and expected to increase in the coming years as the industry expands. 80 Fed. Reg. at 56,599. For these reasons, EPA now believes it has proper grounding to proceed with direct methane standards for oil and gas sources. While we maintain that the Clean Air Act required EPA to regulate methane in 2012 or earlier, we affirm that post-2012 Reporting Program data (as well as other data gathered and/or made available since 2012) provide the agency with a rational basis to issue the proposed rule.

EPA's authority to adopt new source standards for methane from the oil and gas industry is clear regardless of the methane co-benefits already expected from certain upstream sources under the 2012 VOC rule. Nothing in the text, history, or structure of section 111(b) prohibits the agency from requiring sources to control their emissions of a dangerous pollutant simply because the sources must already control *different* pollutants using the same or similar methods. Rather, section 111 compels EPA to adopt performance standards even when other legal requirements address part of the same pollution problem as a practical matter. As EPA rightly notes,

> [w]hile the VOC standards in the 2012 NSPS also reduce methane emissions, in light of the current and projected future methane emissions from the oil and natural gas industry, reducing methane emissions from this source category cannot be treated simply as an incidental benefit to VOC reduction; rather, it is something that should be directly addressed through standards for methane under section 111(b) based on direct evaluation of the extent and impact of methane emissions from this source category and the best system for their reduction.

Id. D.C. Circuit case law affirms that EPA must regulate a source's emissions of a particular pollutant even where the source already controls those emissions as a result of complying with other legal obligations. For instance, in *State of N.Y. v. Reilly*, 969 F.2d 1147, 1153 (D.C. Cir. 1992), the court rejected EPA's argument that it need not ban the burning of lead-acid vehicle batteries under the NSPS for municipal waste combustors because "the Resource Conservation and Recovery Act includes strict provisions against the burning of lead-acid batteries." The court responded that "the mere existence of other statutory authority which might undergird EPA's final stance is insufficient to justify the omission of the battery ban." *Id.* Similarly, in *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 191 (D.C. Cir. 2011), the court rejected legal challenges to an NSPS limit for PM that tracked a concurrently-issued PM standard adopted under section 112. The court explained that, "[a]lthough both the NSPS and NESHAP rulemaking resulted in a PM emissions limit of 0.01 pounds per ton, EPA arrived at that limit using two different mechanisms," while acknowledging that "the final rule . . . noted that kilns would have to install fabric filter technology to comply with NESHAP, concluding that the parallel NSPS rule would therefore have no additional cost." *Id.*

In the current rulemaking, EPA is not proposing to control a pollutant already regulated under a different rule or program, but merely one that is incidentally reduced through regulations for another pollutant at certain sources. In fact, the two pollutants at issue here—methane and

VOCs—are emitted in highly disparate quantities during oil and gas development and have differing environmental and public health impacts. Methane has powerful climate-disrupting properties, and it contributes to background ozone formation. By contrast, VOCs do not have significant direct climate-forcing effects, but are direct precursors to both localized ozone and fine particulate matter, and therefore have a major impact on soot and smog formation. Section 111(b) charges EPA with limiting dangerous pollution from new infrastructure. If the agency failed to address one or both of these pollutants from oil and gas sources, it would be falling short of its statutory mandate.

EPA's approach will also help fulfill the agency's obligation to adopt an effective set of methane emission guidelines for existing oil and gas equipment in the future. In drafting section 111, Congress directed the Administrator to list categories of sources based on a category's impact on air quality, without distinguishing new versus existing sources. 42 U.S.C. § 7411(b)(1)(A). Congress then required EPA to address both new and existing sources of air pollution in each listed category. *Id.* and 7411(d). Because section 111 makes the extent of the agency's authority to regulate existing equipment contingent on the scope of the new source performance standards adopted under section 111(b), *see* 42 U.S.C. § 7411(d)(1)(A)(ii), establishing new source standards covering methane emissions from equipment already subject to VOC standards is essential to fulfilling the agency's statutory obligation to reduce dangerous methane emissions from the oil and gas industry, including the most significant existing sources of that pollutant. Moreover, as discussed above, the agency's failure to issue NSPS for methane emissions in 2012 was arbitrary and unlawful, and curtailing the coverage of existing sources by limiting the scope of the proposed standards to facilities not subject to the 2012 VOC rule would only compound that error. But even if EPA's failure to address methane in 2012 represented a valid exercise of the agency's discretion, there is no rational basis for declining to adopt methane standards solely on the basis that EPA chose to regulate VOC and methane from new sources in separate rulemakings.

2. EPA Has Authority To Create a New Supbart OOOOa for Its Proposed Methane Standards For Oil and Gas Sources

EPA is also correct to propose a new subpart to house its methane regulations for oil and gas sources. Because new source performance standards only apply prospectively, the agency's regular practice is to create a new subpart whenever it regulates a pollutant not previously covered under section 111 for a listed source category, or whenever it revises the applicable regulations for that category. For example, in 2008, EPA issued updated performance standards for petroleum refineries that tightened the allowable emission limitations for PM, CO, and SO_2. These standards also limited refineries' NO_x emissions for the first time. The new standards, which were issued under 40 C.F.R. § 60, subpart Ja, applied to units built or modified after March 14, 2007, whereas the earlier standards, listed under subpart J, continued to apply to units that came online prior to that date. Similarly, when EPA strengthened its NO_x standards for nitric acid plants in 2012, it placed them in new subpart Ga, which applied to units built or modified after October 14, 2011. The earlier, less stringent standards remained in subpart G and remained applicable to units built before the October 2011 date. Other examples of this practice abound through EPA's regulatory history, and its creation of subpart OOOOa is entirely in line with that history.

D. EPA Has Authority to Establish Standards for Downstream Sources in All Segments of the Oil and Gas Source Category Covered by Subpart OOOOa.

EPA's interpretation that its 1979 published list of source categories "generally cover[ed] the oil and natural gas industry," including "production, processing, transmission, and storage," is reasonable. 80 Fed. Reg. at 56600. At the time of the listing, EPA recognized that many of the source categories the agency was evaluating emitted pollutants from multiple processes within the sectors, and EPA claimed to lack adequate information to accurately analyze the emissions for many of these sources. 44 Fed. Reg. 49,222, 49,224 (Aug. 21, 1979). EPA's answer to the challenge posed by these source categories was to aggregate the different emission sources into a single, broad source category. *Id.* (using the synthetic organic chemical manufacturing industry as an example); Standards of Performance for New Stationary Sources, 43 Fed. Reg. 38,872, 38,875 (Aug. 31, 1978) (same). Given the breadth and complexity of the various emission sources within the oil and gas sector it is reasonable for EPA to interpret the 1979 Crude Oil and Natural Gas Production listing as including the transmission and storage segments.

Even if the original 111 listing did not cover these downstream segments, we agree that EPA has made the necessary demonstration to support a revision to the source category under section 111(b)(1)(A). Indeed, EPA provides extensive information in the preamble concerning the significant emissions from the transmission and storage segments, noting that this information only further confirms EPA's prior endangerment and contribution findings. We urge EPA to clarify that this significant volume of emissions from transmission and storage justifies its inclusion in the source category either under the rational basis test or a formal cause-or-contribute standard.

E. EPA's General Approach to Determining BSER Is Lawful.

EPA has determined that the BSER for methane for the oil and gas sources already regulated for VOC emissions is the same as the BSER for VOC, and, accordingly, that the current VOC standards also reflect the BSER for methane reduction for the same emission sources. With respect to equipment used category-wide, of which only a subset of those equipment are covered under the NSPS VOC standards (such as pneumatic controllers, and compressors located other than at well sites), EPA has determined that the BSER for reducing VOC from the remaining unregulated equipment is the same as the BSER for those currently regulated. As such, EPA has proposed to extend the current VOC standards to the remaining unregulated equipment.

We support EPA's methodology in making BSER determinations. However, the proposed rule must be strengthened by eliminating certain exclusions and expanding the coverage of certain standards. Our standard-specific recommendations are detailed in sections III-IX below.

1. EPA's BSER determinations have robust support in scientific analysis and technical analysis, as well as state experience

As discussed above, pursuant to section 111, EPA must show that its selected BSER represent the best systems of emission reduction that have been adequately demonstrated, taking into account cost and other required factors. The standards EPA has proposed manifestly meet that requirement. As evidenced by EPA's own diligent technology review and white paper process, the agency's BSER determinations are supported by a substantial body of scientific and technical research and analysis, as well as actual state and industry experience.

EPA's White Paper process in 2014 reviewed and synthesized existing scientific and technical information on oil and gas sector emission control techniques from five major emissions sources: compressors, well completions, equipment leaks, liquids unloading, and pneumatic devices.[37] To calculate emissions estimates, the white papers relied on over twenty years of data from the Gas Research Institute ("GRI"), the Greenhouse Gas Reporting Program and GHGI, technical analysis prepared for the subpart OOOO rulemaking, the Natural Gas STAR program, as well as numerous comprehensive independent studies.[38] The white papers requested comment on emission, reduction, and cost estimates made; methodologies used, control options not covered, technical limitations not covered, and sources of data not reviewed. The agency received and reviewed comments from numerous stakeholders, including states and energy industry companies.

Further establishing EPA's BSER evaluation as eminently reasonable, leading oil and gas-producing states such as Colorado, Wyoming, and California have a long and established history of deploying the control requirements that EPA has selected as BSER. And major companies in the industry have implemented these measures internally as best practices[39] and as part of EPA's Natural Gas STAR program. For example, "Reduced Emission Completions," or RECs are already widely used. Both Colorado[40] and Wyoming[41] require the use of RECs for certain wells, and the Natural Gas STAR program reports that RECs have been a major source of methane emission reductions among its Partners since 2000.[42] Similarly, both states have required the use of low- or no-bleed pneumatic devices.[43] Natural Gas STAR Partners reported significant

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[37] EPA, Methane: Addressing Greenhouse Gases and Smog forming VOCs from the Oil and Gas Industry, *available at* http://www3.epa.gov/airquality/oilandgas/methane.html (providing access to the five technical white papers and the peer reviewer comments received for each).
[38] *See id.*
[39] **Ex. 1,** Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Permit by Rule for Existing Sources (April 13, 2015) (noting the company's internal policy of conducting LDAR using infrared camera surveys).
[40] Co. Oil & Gas Conserv. Comm'n ("COGCC") Rule 805(b)(3), (Sept. 2014), *available at* https://cogcc.state.co.us/RR_Docs_new/rules/800series.pdf (requiring the use of RECs where they are "technically and economically feasible").
[41] Wy. Oil and Gas Production Facilities Permitting Guidance (Sept. 2013) ("WY Permitting Guidance"), at 15, 20, *available at* http://deq.wyoming.gov/aqd/new-source-review/resources/guidance-documents/ (requiring RECs in 'concentrated development areas' comprised of six counties).
[42] EPA, Reduced Emissions Completions: Lessons Learned from Natural Gas STAR Partners at 1 (2011), *available at* http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf. *See also* EPA, Reducing Methane Emissions During Completion Operations (Oct. 24, 2006), available at http://www3.epa.gov/gasstar/documents/vincent.pdf.
[43] Co. Oil and Gas Conserv. Commission Rule 805(b)(2)(D) (Sept. 2014), *available at* https://cogcc.state.co.us/RR_Docs_new/rules/800series.pdf (requiring that low- or no-bleed pneumatic devices be used when pneumatic devices are replaced or repaired, and when new pneumatic devices are

savings from the use of low-bleed devices as early as 2006.[44] Long-existing state regulations and company policies such as these more than "adequately demonstrate" the feasibility and suitability of EPA's chosen BSER measures.

2. EPA's Approach to Considering Costs is Reasonable

EPA has assessed cost as part of its BSER determination in several ways. The agency evaluated the cost-effectiveness of each available control technology under both a single pollutant approach and a multi-pollutant approach, considering a device cost-effective if it was cost-effective under either of the two approaches. The agency also evaluated industry wide costs as a percentage of capital expenditures. EPA has provided a reasonable explanation for its chosen approaches.

EPA's use of a single pollutant approach to considering costs is appropriately limited in the proposed rule. This approach, which allocates all costs to each individual pollutant, double-counts costs or ignores entirely the benefits of reducing one of the two pollutants. As EPA notes, the single pollutant approach "over-estimates the cost of obtaining emissions reductions with a multipollutant control as it does not recognize the simultaneity of the reductions achieved." 80 Fed. Reg. at 56,617. Moreover, courts have held that, when conducting a cost-benefit analysis for a multi-pollutant emission control measure, an agency cannot attach zero value to the reduction of one of the pollutants, where such reduction is difficult to quantify. *Ctr. for Biological Diversity v. NHTSA*, 538 F.3d 1172 (9th Cir. 2008). Similarly, the agency cannot attach the entire cost to the reduction of each individual pollutant, where it is difficult to assign cost among multiple pollutants. It must choose an approach that most closely recognizes the relative costs and benefits of reducing each pollutant. The single pollutant approach misses this mark.

In contrast, a multi-pollutant approach apportions the total cost of an emission control option among all of the pollutants reduced by that control option. Although there are several plausible ways in which such apportionment might be effectuated, EPA's proposed approach for this rulemaking - which apportions cost evenly to methane and VOCs based on the relative percentage abatement of these two pollutants – is a sensible one. Multi-pollutant cost-effectiveness calculations better approximate the true costs of pollution reduction. Multi-pollutant cost sharing is particularly warranted where, as here, both pollutants, methane and VOC, are directly regulated under section 111. Recognizing this, EPA adopted both approaches, but opted to utilize the single pollutant approach only as a lower threshold test of the reasonableness of a control option – "if the cost is reasonable for reducing any of the targeted emissions alone, the cost of such control is clearly reasonable for the concurrent emission reduction of all the other pollutants because they are being reduced at no additional cost." 80 Fed. Reg. at 56,617. EPA has adopted a multi-pollutant approach in past rulemakings, *see, e.g.*,

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installed); Wy. Dept. of Envt'l Quality, Oil and Gas Production Facilities (Sept. 2013) at 10-11, *available at* http://deq.wyoming.gov/aqd/new-source-review/resources/guidance-documents/ (requiring all new and modified controllers to be low or no-bleed and that pumps achieve 98% emission control, or routing to a closed loop system).

[44] EPA, Lessons Learned from Natural Gas Star Partners: Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry (2006) at 1, *available at* http://www3.epa.gov/gasstar/documents/ll_pneumatics.pdf.

National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plant, 75 Fed. Reg. 54,970; *see also* cost analysis in proposed rule, 74 Fed. Reg. 21,136 (May 6, 2009), and even issued a report in 2008 addressing the need for regulations to recognize shared emissions sources, and the multi-pollutant effects of control technologies.[45]

EPA separately compares control costs to annual capital expenditures and revenue, a crucial factor in evaluating the economic impact that the cost of control measures may have on the industry. EPA uses U.S. Census data to determine what percentage the capital costs incurred by facilities to comply with the proposed standards represent of capital expenditures, and what percentage such capital costs represent of annual revenues. This analysis closely aligns with the case law and with past regulatory precedents which focus either on the costs of achieving emission reductions relative to the amount of reductions achieved, or impacts on the industry or the economy. *See Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).

Lastly, EPA's control cost analysis takes into consideration estimated savings operators can expect from selling natural gas that control measures capture**.** This approach clearly falls within EPA's discretion under section 111. While the D.C. Circuit has yet to address directly whether EPA may take revenue generated in conjunction with control options into account in evaluating BSER, the court has held that the agency retains broad authority to weigh all the statutory factors in a BSER determination, noting that questions of costs and benefits must be addressed taking a long-term perspective. *See Sierra Club*, 657 F.2d at 331.As EPA notes, it is a reasonable interpretation of section 111 that expected revenue from the sale of natural gas that is recovered as a result of a control option be considered in accurately assessing the costs of the standard, as it "would offset regulatory costs." 80 Fed. Reg. at 56,617. The practice also comports with EPA's approach to material savings achieved through emission standards in prior NSPS rulemakings. *See* Standards of Performance for Petroleum Refineries; Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, 77 Fed. Reg. 56422 (Sept. 12, 2012) (EPA evaluated fuel savings from improved flare standards and calculated a product recovery credit). Inclusion of the value of gas savings better approximates the true cost to operators.

F. EPA Must Not Further Delay Issuing Section 111(d) Existing Source Emission Guidelines.

EPA must act swiftly to propose and adopt emission guidelines for existing sources of methane in the oil and gas sector, as such action on existing sources is critical to achieving the Administration's goal that methane from the oil and gas sector be reduced by 40-45% from 2012 levels by 2025. Taking action to address existing sources of methane is mandated by the statutes and the agency's own regulations.

EPA's regulations implementing section 111(d) require the agency to propose emission guidelines for existing sources "[c]oncurrently upon or after proposal of standards of performance" under section 111(b). 40 C.F.R. § 60.22. While the regulation text is silent on how

[45] EPA, The Multi-pollutant Report (2008), *available at* http://www3.epa.gov/airtrends/specialstudies/20080702_multipoll.pdf.

long "after" proposal of a new source performance standard EPA may delay in proposing existing source guidelines, the purpose and regulatory history of the rule provide insight about the meaning of the term. *See Howmet Corp. v. EPA*, 614 F.3d 544 (D.C. Cir. 2010) (assessing the regulatory history of a provision and the overall purpose of RCRA in determining the reasonableness of EPA's interpretation of ambiguous regulatory language). This history shows that EPA must act as quickly as possible to control existing sources to protect the public health and welfare.

EPA's original proposed rule to implement section 111(d) highlighted the relationship between 111(b) new source standards and 111(d) emission guidelines, observing that "[w]hen standards of performance have been promulgated for designated pollutants, the Act requires that States submit plans which establish emission standards for existing sources…." *See Standards of Performances for New Stationary Sources; State Plans for the Control of Existing Facilities,* 39 Fed. Reg. 36102 (Oct. 7, 1974). Those proposed regulations would have required EPA to propose existing source emission guidelines at the same time as the agency proposed the corresponding new source standards. *Id.* at 36103.

The final rule however changed this provision so that EPA was required to propose an emission guideline after promulgation of the corresponding new source standard. State Plans for the Control of Certain Pollutants From Existing Facilities, 40 Fed. Reg. 53340, 53345-46 (Nov. 17, 1975). The agency made this change in response to comments asserting that "more time was needed to evaluate a standard of performance and the corresponding emission guideline than would be allowed by simultaneous proposal and promulgation." *Id*. at 53345. The agency also noted that by proposing an emission guideline after the new source standard, EPA could benefit from comments on the standard of performance in developing the emission guideline. Thus, EPA required 111(d) action "after" final 111(b) rules, in order to provide the agency time to assess information gained through the new source standards process.

Over a decade later, EPA revised this language once again to enable simultaneous proposal and promulgation of emission guidelines and new source performance standards. Standards of Performance for New Stationary Sources; State Plans for Designated Facilities, 54 Fed. Reg. 52188 (Dec. 20, 1989). In proposing this change, EPA explained that—

> Depending on the specific source category involved, simultaneous proposal of the new source performance standard and publication of the associated draft emission guidelines document may be reasonable and necessary to efficiently achieve the goal of protecting public health and welfare. For example, when regulatory studies of new and existing sources can be completed at the same time, waiting until promulgation of the new source performance standard before publishing the draft emission guideline would unnecessarily delay control of existing sources.

Standards of Performance for New Stationary Sources; State Plans for Designated Facilities, 53 Fed. Reg 12962, 12963 (Apr. 20, 1988). EPA cited the example of its forthcoming NSPS and emission guidelines for municipal waste combustors, explaining that "[s]ince both new and existing sources have been studied simultaneously, this source category is an example of an instance where it would be reasonable to publish the draft emission guideline document at the same time the new source performance standard is proposed." *Id.*

In response to the proposal, two commenters submitted "that important information could be attained by EPA if the draft guidelines were made available for the regulated public to review prior to promulgation of the standards." 54 Fed. Reg. at 52188. EPA, responding to those comments, recognized the value of acting expeditiously to provide information and control existing sources by stating that the agency "agrees it would be useful, in most cases, to receive comments on the draft guidelines at the same time as the standards of performance are proposed, thereby alleviating any unnecessary delay of controls of existing source categories." *Id.*

Here, EPA's simultaneous study of systems of emission reduction for both new and existing sources in the oil and gas sector parallels the situation that led EPA to revise its approach to the timing of emission guidelines. For example, the agency's 2014 White Papers on emission sources in the oil and gas sector focused on both new and existing sources, enabling EPA to gather information crucial to the development of emission guidelines for existing sources. Moreover, EPA has demonstrated – through its 2014 White Papers, these proposed new source standards, and its proposed control techniques guideline document – that it currently has sufficient information on which to base section 111(d) emission guidelines. Indeed, existing sources of methane in the oil and gas sector can be addressed through the same control methods as apply to new sources. Accordingly, EPA must move forward swiftly with emission guidelines that address methane from existing sources in the oil and gas sector.

III. Leak Detection and Repair

Equipment leaks are the most significant source of methane emissions from the oil and gas sector, and readily available technologies exist to find and fix these leaks. Rigorous leak detection and repair standards are therefore an indispensable element of a comprehensive program to address methane emissions from the oil and gas sector. Although we welcome EPA's decision to propose leak detection and repair (LDAR) requirements for well sites, compressor stations, and natural gas processing plants, we also believe EPA's proposal is flawed in critical respects. In the final rule, we urge EPA to adopt LDAR requirements that are aligned with industry best practices and leading state-level requirements, and consistent with the most recent science on equipment leaks.

In Part A below, we describe recent scientific evidence that methane pollution from leaks is even larger than inventories currently reflect, and outline state and industry experience with technologies that enable rigorous LDAR. Parts B and C recommend strengthening certain key features of EPA's proposed LDAR standards, including the scope of those requirements and their frequency. In Part D, we provide support for EPA's proposed definition of modification and urge EPA to identify additional activities that likewise constitute modifications under the Act. Part E addresses additional, specific questions on which EPA has requested comment, and Part F concludes with recommendations for incentivizing development of advanced monitoring technologies.

In short, our recommendations to EPA are as follows:

Scope of Application

- Clarify that LDAR applies to potentially high-emitting gathering facilities that have dehydrators but lack storage tanks and compressors.
- Revise the definition of "fugitive emissions components" to require monitoring of intermittent-bleed pneumatic controllers, which are known to function improperly and produce significant emissions.
- Remove the 15 barrels of oil equivalent per day (BOE/d) exemption and, if needed to mitigate cost concerns, consider requiring less frequent monitoring at these sites.
- Narrow the exemption for well sites that contain one or more wellheads and no associated equipment so that it applies to single wellheads only.
- For Gas Processing Plants, eliminate the exemption for equipment that handles "low-VOC gas," which appears to have been inadvertently carried over from the VOC standards EPA issued in 2012.

Frequency of Monitoring

- Adopt a quarterly monitoring schedule at well sites and compressor stations, in light of substantial evidence supporting the cost-effectiveness of quarterly and other more frequent monitoring programs. Alternatively, to calibrate frequency requirements at well sites, EPA could adopt an approach that is tiered based on facility size, similar to Colorado's rule.
- Eliminate provisions allowing operators to adjust frequency based on the percentage of leaking components identified in prior surveys, or, alternatively, tie frequency adjustment thresholds to an emission intensity metric rather than the percentage of leaking components.

Modifications

- Finalize proposed definitions of modifications and include additional activities like certain workovers and additional equipment like dehydrators.

Advanced Technologies

- Finalize a pathway that allows operators or other third parties to use advanced, alternative monitoring technologies if accompanied by a rigorous, transparent demonstration that these technologies secure equivalent or superior emission reductions.

A. Equipment Leaks are the Largest Source of Emissions from the Oil and Gas Sector and Readily Available Solutions Exist to Address this Pollution.

Equipment Leaks are a Significant Source of Emissions. Leaked emissions of methane and VOCs from the oil and gas industry are significant. According to the 2013 GHG Inventory, fugitive emissions account for 35% of emissions from the natural gas and upstream petroleum sectors.[46] ICF has found that leaks are the largest emissions category in the oil and gas industry, estimating that emissions from these sources will account for nearly 2.3 million metric tons of

[46] 2013 GHGI. Using methodology described in CATF, et al., *Waste Not*. Technical Appendix, Section 1. Leaks, at 53, *available at* http://www.catf.us/resources/publications/files/WasteNot.pdf.

methane in 2018, or 30% of all emissions from the oil and gas sector.[47]

Table 1: Oil and Gas Sector Emissions

	Leaks			Total Sector Emissions	Percent of Sector Emissions
	Non-Compressor Leaks	*Compressor Leaks*	**Total Leaks**		
Production	*243,993*	*39,261*	**283,254**	**2,847,530**	**10%**
Processing	*27,978*	*388,077*	**416,056**	**906,407**	**46%**
Transmission and Storage	*216,813*	*959,440*	**1,176,254**	**2,176,478**	**54%**
Distribution (aboveground)	*691,795*	-	**691,795**	**1,332,529**	**52%**
Total	*1,180,579*	*1,386,778*	2,567,358	**7,262,945**	**35%**

Moreover, recent scientific research—conducted across various geographies and value chain segments, and with diverse methodologies— confirms that leaks are a significant source and suggests that current inventories likely underestimate their magnitude. In particular:

- **Barnett Shale Field Campaign**. A recent series of studies in the Barnett—incorporating both top-down and bottom-up measurement—found that emissions were 50 percent greater than estimates based on the GHGI.[48] The studies partially attributed these large emissions to high emission sites not reflected in inventories, which focus on average emission factors. One study in particular found that a small number of sources are responsible for a disproportionate amount of emissions, noting specifically that "sites with high proportional loss rates have excess emissions resulting from abnormal or otherwise avoidable operating conditions, such as improperly functioning equipment."[49]

- **Allen et al (2013)**. A study conducted by an independent team of scientists at the University of Texas found that emissions from equipment leaks were 38 percent higher than estimated in EPA's GHG Inventory.[50] Importantly, this study examined the same components included in those inventories, such as valves and connectors. Even without

[47] ICF International, *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries* B-6 (March 2014) ("ICF (2014)") at 3-9, *available at* http://www.edf.org/sites/default/files/methane_ cost_curve_report.pdf.

[48] Harriss et al., (2015) "Using Multi-Scale Measurements to Improve Methane Emissions Estimates from Oil and Gas Operations in the Barnett Shale, Texas: Campaign Summary," *Environ. Sci. Technol.*, *49*, **13** ("Harriss (2015)"), *available at* http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305 (providing a summary of the 12 studies that were part of the coordinated campaign).

[49] Zavala-Araiza, et al., (2015) "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," *Environ. Sci. Technol*. 2015, *49*, **13**, at 8167−8174 ("Zavala-Araiza (2015)"), *available at* http://pubs.acs.org/doi/pdfplus/10.1021/acs.est.5b00133.

[50] Allen, D.T., et al, (2013) "Measurements of methane emissions at natural gas production sites in the United States," *Proc. Natl. Acad.*, *110*, 44 ("Allen (2013)"), *available at* http://www.pnas.org/content/110/44/17768.full.

observing other significant fugitive emission sources that have also been overlooked by national inventories, such as thief hatches on storage tanks or improperly functioning separator dump valves, this study found that those inventories underestimated leaks.

- **Allen et al (2015).** As part of the second phase of the study discussed above, researchers investigated emissions from pneumatic devices at oil and gas production facilities. The study identified emissions from different types of pneumatic devices serving various functions and found that "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design. For example, some devices not designed to bleed intermittently had continuous emissions."[51] Emissions from these improperly functioning devices are not captured by many inventories, especially those that rely on standardized emissions factors.

- **Gathering and Processing Study.** In another study, researchers found substantial venting from liquids storage tanks at approximately 20 percent of sampled gathering facilities, with emission rates at these facilities four times higher on average than rates observed at other facilities. At some sites with substantial emissions, the authors found that company representatives, upon learning of the emissions, made adjustments resulting in immediate reductions in emissions.[52] While not strictly considered to be "fugitive emissions" by EPA, these venting emissions from liquids storage would be identified and addressed by an LDAR program.

- **Transmission and Storage Study.** Researchers also found that fugitive sources account for 75 percent of emissions in the transmission and storage segments, concluding that measured emissions are 260 percent larger than would be estimated by the emission factors used in EPA's Reporting Program.[53]

These large emissions are due both to smaller sources that are collectively significant and to disproportionately unusual, but very large leaks commonly referred to as emitting "super-emitters." Many studies have demonstrated that there is a highly skewed distribution of leaks. The concentration of emissions within a small proportion of sources has been observed both among groups of components within a site and among groups of entire facilities. EPA's White Paper on Fugitive Emissions[54] generally describes this type of distribution, with the majority of

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[51] Allen, D.T., et al, (2015) "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environ. Sci. Technol.*, *49*, **1**, 633–640 ("Allen (2015)"), *available at* http://pubs.acs.org/doi/abs/10.1021/es5040156.

[52] Mitchell, A.L., et al., (2015), "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results," *Environ. Sci. Technol.*, *49*, **5**, 3219-3227 ("Mitchell (2015)"), *available at* http://pubs.acs.org/doi/abs/10.1021/es5052809.

[53] Subramanian, R., et al., (2015), "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol.*, *9*, **5**, 3252–3261 ("Subramanian (2015)"), *available at* http://pubs.acs.org/doi/abs/10.1021/es5060258. *See also* Zimmerle, D., et al., (2015), "Methane Emissions from the Natural Gas Transmission and Storage System in the United States," *Environ. Sci. Technol.*, *49*, **15**, at 9374–9383, *available at* http://pubs.acs.org/doi/abs/10.1021/acs.est.5b01669.

[54] EDF, Peer Review Response, "Oil and Natural Gas Sector Leaks," (June 16, 2014) ("EDF Leak Response"), *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/attachmentl.pdf.

emissions coming from a minority of components and a minority of sites.[55] Both the City of Fort Worth Natural Gas Air Quality Study[56] and Allen, *et al.* (2013)[57] provide extensive, site-wide emissions data that confirm the presence of super-emitters. In these studies, the highest 20 percent of emitting sites account for 60–80 percent of total emissions from all sites; the lowest 50 percent of sites account for only 3–10 percent of total emissions. Figure 1 below presents site-wide emissions for natural gas production facilities from both of these studies. Emission rate distributions from different source types are plotted as percent of sites in ascending order of emission rate versus percent of total emissions from sites at or below that rank. For example, the lowest emitting 50% of well pads contribute 1% of total emissions from measured sites, while the highest emitting 10% contribute 69% of total emissions. As is illustrated, all the studies represented in the figure observe roughly the same trend across all sectors of the value chain.

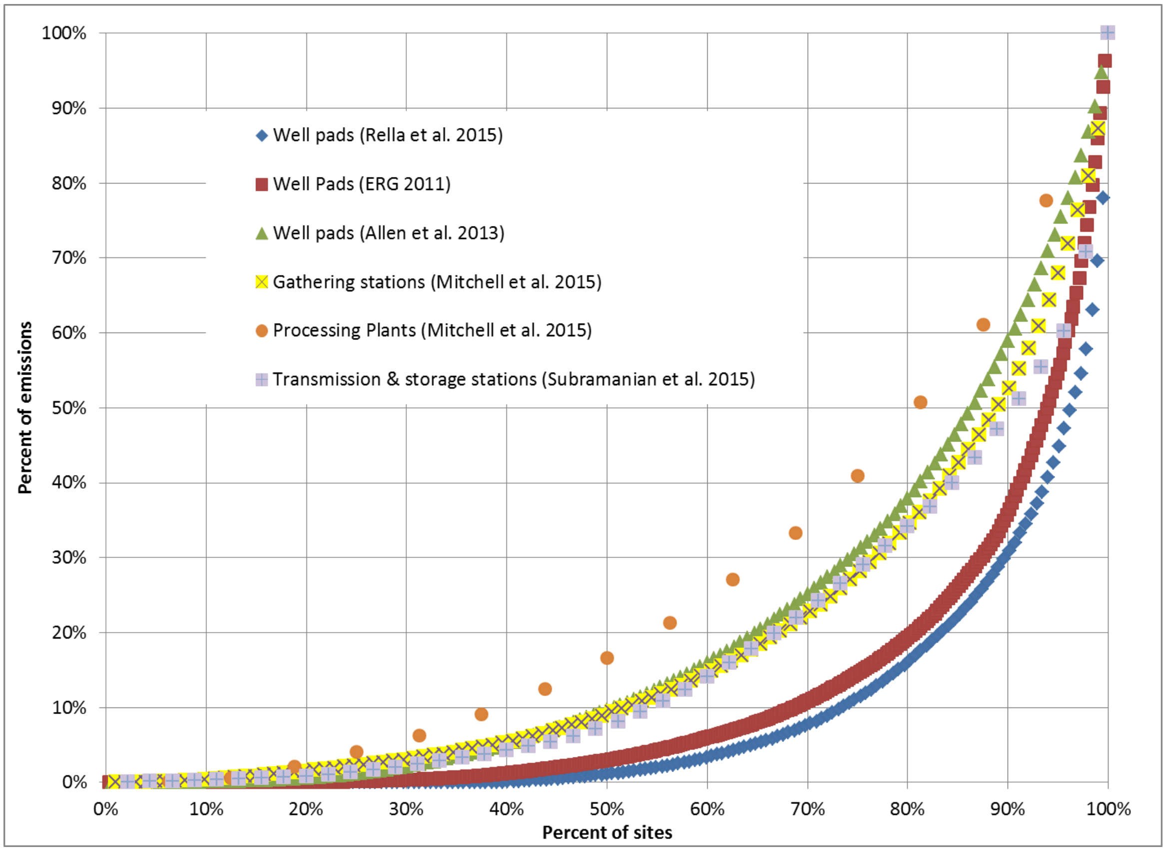
Fig. 1: Distribution of Site-Wide Emissions at Natural Gas Production Sites.[58]

[55] EPA's White Paper cites the Carbon Limits study (2013), the Clearstone I and II studies (2002 and 2006) and Thoma et al. (2012). *Id.* at 5-6.

[56] ERG and Sage Environmental Consulting, LP, *City of Fort Worth Natural Gas Air Quality Study, Final Report.* ("Fort Worth Study") (July 13, 2011), *available at* http://fortworthtexas.gov/gaswells/default.aspx?id=87074.

[57] Allen (2013).

[58] Rella, et al., (2015) "Measuring Emissions from Oil and Natural Gas Well Pads Using the Mobile Flux Plane Technique" *Environ. Sci. Technol*., *49*, **7**, 4742–4748, *available at* http://pubs.acs.org/doi/abs/10.1021/acs.est.5b00099; Fort Worth Study; Allen (2013) at 17771; Mitchell (2015), 3219–3227; Subramanian (2015) 3252–3261.



Equally important, studies have found that these super emitters—and, indeed, leaks in general—are at present largely unpredictable and may shift over time. In particular, the Barnett coordinated campaign mentioned above found that abnormal operating conditions, such as improperly functioning equipment could occur at different points in time across facilities.[59] As a result, Zavala-Araiza, et al. reported that inspections need "to be conducted on an ongoing basis" and "across the entire population of production sites."[60]

These results suggest that an effective emission reduction strategy must include frequent leak surveys to identify the highest emitting sites and address sources at those sites. Ultimately, the existence of super-emitters underscores that a comprehensive policy to address emissions is critical—one that focuses on detection and remediation of leaking sources using approaches that are well-adapted to finding the highest-emitting sources and sites.

Technologies are readily available to identify and to help reduce these emissions. Technologies that enable rigorous leak detection are available today, and are continuously improving. Optical gas imaging (OGI) systems have rapidly advanced to the forefront of leak detection technology, primarily because of the speed with which these technologies can detect large leaks and other important advantages over Method 21 or non-instrument based methods:

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[59] Harriss (2015).
[60] Zavala-Araiz (2015), at 8167−8174.

- **Speed.** OGI can be used to quickly and comprehensively scan an entire facility for leaks, thereby detecting improperly functioning equipment from a safe vantage point. The Colorado Air Pollution Control Division estimates that operators can scan a facility for leaks twice as quickly using an infrared ("IR") camera as they can using a Method 21-compliant device.[61] Some experts suggest that this is a conservative estimate of the time savings associated with the use of OGI technology, and that OGI camera scans can be performed even more efficiently.[62]

- **Comprehensive Inspection.** Moreover, OGI technology with IR cameras is proven to enable efficient site-level assessments, including difficult-to-access components.[63] A clear illustration of this is that operators can detect leaks atop storage tanks using an IR camera that would otherwise go undetected unless an inspector climbed to the top of the tank.[64] This allows open thief hatches or other malfunctions to be promptly addressed once detected, without requiring an inspector to climb the tank on every leak survey. In addition, as EPA recognizes, OGI can help operators detect sources of emissions, such as a crack or corrosion in a run of pipe or along the surface of a tank. Operators are not specifically required to inspect the equipment or locations of those sources covered under the program's requirements. 80 Fed. Reg. at 56,637.

- **Accuracy and Efficacy.** Although technologies such as OGI do not currently quantify leaks, detection itself is of primary importance, since most leaks are cost-effective to repair once detected.[65] The quantitative comparisons that exist indicate that OGI is as effective as Method 21 in detecting all but the smallest leaks.[66]

The establishment of OGI-based LDAR programs is a central feature of many leading state standards. Five states—Colorado, Pennsylvania, Ohio, Utah, and Wyoming—have adopted

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[61] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) ("CAPCD Cost-Benefit"), at 20, *available at* ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/COST%20BENEFIT%20ANALYSIS%20&%20EXHIBITS/CDPHE%20Cost-Benefit%20Analysis_Final.pdf.

[62] ICF (2014), at 3-10 to 3-11. *See also* Target Emission Services, "LDAR Case Study: Comparison of Conventional Method 21 vs. Alternative Work Practices (Optical Gas Imaging)," Presentation at 2015 Gas Technology Institute Conference ("TES LDAR 2015"), at 8, *available at* http://www.gastechnology.org/CH4/Documents/13-Terence-Trefiak-CH4-Presentation-Oct2015.pdf.

[63] Consent Decree *U.S. v. Noble Energy*, (No. 1:15 cv 00841, D. CO., April 22, 2015) ("Noble Energy Consent Decree"), *available at* http://www.justice.gov/sites/default/files/enrd/pages/attachments/2015/04/23/lodged_consent_decree.pdf; *see also* EPA Compliance Alert, "EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities," (Sept. 2015) ("EPA Compliance Alert 2015"), available at http://www2.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf.

[64] See *id*. *See also* Mitchell (2015), at 3219-3227.

[65] Ex. TA2, Letter from Jonah Energy LLC to Steven A. Dietrich, Administrator, Wyoming Department of Environmental Quality (Dec. 10, 2014), at 2 (discussing its voluntary LDAR program and stating that "the estimated gas savings from the repair of leaks identified exceeded the labor and materials cost of repairing the identified leaks."); Carbon Limits, *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras*, CL-13-27 (Mar. 2014) ("Carbon Limits 2014"), *available at* http://www.catf.us/resources/publications/files/.

[66] EDF Leak Response, at 15-16; TES LDAR 2015.

LDAR requirements for oil and gas facilities that allow the use of OGI instruments as a means of compliance.[67] California has proposed quarterly LDAR standards at new and existing sources statewide that would require the use of OGI instruments.[68] And since 2011, EPA's Reporting Program has allowed the use of OGI cameras to detect leaking components at above-ground facilities in natural gas processing, transmission, storage, and distribution, as well as at liquefied natural gas import/export facilities.[69]

Many leading operators have also deployed OGI to help detect and repair leaks. Companies such as Shell, Anadarko Petroleum Corporation, and Noble Energy have indicated that they are utilizing IR cameras for LDAR purposes.[70] More specifically, Jonah Energy's Enhanced Direct Inspection & Maintenance ("EDI&M") Program in Wyoming has been ongoing for the last five and a half years and includes a *monthly* LDAR program using instrument-based surveys (i.e., IR camera technology). This program has resulted in over 16,000 inspections and thousands of repaired leaks identified by IR camera technology and has a reported overall control effectiveness in excess of 75 percent.[71]

At the same time as operators and states are applying OGI technologies, new technologies are emerging. The methane leak detection technology landscape is highly dynamic. ARPA-E's MONITOR project offers numerous examples of possible leak detection advances, sourced from a range of leading technology firms such as GE and IBM.[72] EDF's Methane Detectors Challenge, in partnership with technology companies, large producers, and other stakeholders, is developing continuous detection of facility-wide emissions. Continuous detectors will cost-effectively and reliably identify leaks as soon as they occur, thereby allowing immediate repairs.[73] Several of these technologies have accurately, continuously, and reliably detected methane leaks in controlled testing.

Figure 2 below illustrates results from these recent tests. The figure indicates that the sensors from all of the innovators represented were able to detect leak concentrations within a narrow

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[67] Co. Dep't of Pub. Health & Env't Reg. No. 7 (5 C.C.R. § 1001-9 XVIII); Pa. Dep't of Envtl. Prot., General Permit for Natural Gas Compression and/or Processing Facilities (GP-5), Section G ("Pennsylvania General Permit"), *available at* http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-94153/2700-FS-DEP4403.pdf; Ohio Envtl. Prot. Agency, General Permit 12.1(C)(5)(c)(2), 12.2(C)(5)(c)(2) ("Ohio General Permit"), *available at* http://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf; Wyo. Dep't of Envtl. Quality, Oil and Gas Production Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised Sept. 2013) ("WY Permitting Guidance"), *available at* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf; Utah Department of Environmental Quality, Division of Air Quality, Approval Order: General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery, II.B.10 (June 5, 2014) ("Utah General Permit"), available at http://www.deq.utah.gov/Permits/GAOs/oilgas/oilgasgao.htm.

[68] California Draft Proposed Regulation Order, April 22, 2015, *available at* http://www.arb.ca.gov/cc/oil-gas/meetings/Draft_Regulatory_Language_4-22-15.pdf.

[69] EPA, Greenhouse Gas Reporting Program, Subpart W, *available at* http://www.epa.gov/ghgreporting/reporters/subpart/w.html.

[70] EDF Leak Response, at 9.

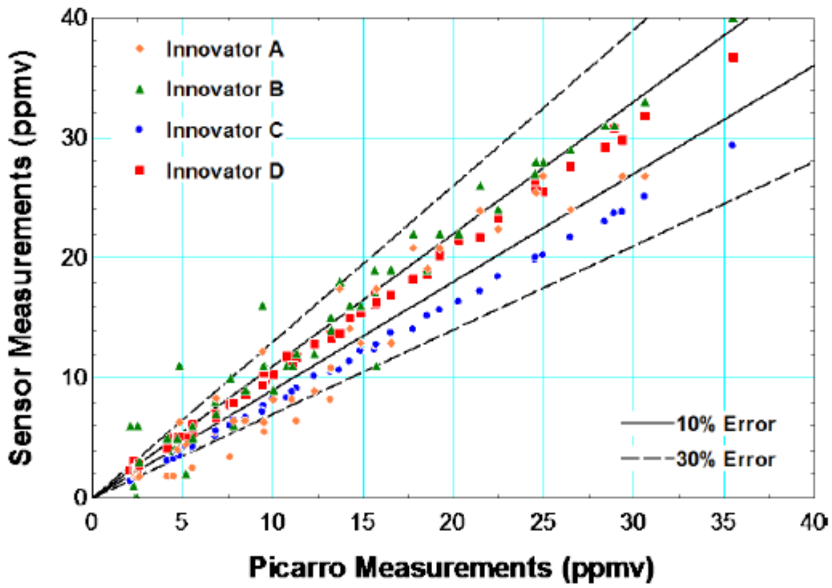
[71] Ex. TA3, Jonah Energy LLC, presentation at the WCCA Spring Meeting, May 8, 2015.

[72] ARPA-E, Monitor, *available at* http://arpa-e.energy.gov/?q=arpa-e-programs/monitor.

[73] SwRI, "Testing of Methane Detection Systems – Phase 2," prepared for EDF (September 18, 2015), *available at* https://www.edf.org/sites/default/files/content/mdc_phase_2_final_report.pdf.

margin of error. Based on these strong testing results, the Methane Detectors Challenge is moving to pilot *continuous* detection systems at production facilities around the country. In the near future, low-cost continuous methane detectors may be commercially available to detect leaks.

Fig. 2 Correlation between Sensor Measurements from Methane Detector Challenge Tests and Picarro Measurements of Ambient Concentrations (in ppmv methane)[74]



As we describe more fully below, it is crucial for EPA's standards to incentivize development of innovative technologies that can deliver improved environmental performance at reduced cost. A robust alternative compliance pathway that creates an entry point for appropriately qualified detecting approaches will help catalyze a race to the top in technology, reduce costs for the regulated community, and potentially boost environmental benefits. States that currently require LDAR already allow for the use of approved innovative detection technologies to comply with regulatory requirements.[75]

B. EPA's Standards Should Apply Comprehensively to Facilities across the Oil and Natural Gas Supply Chain and to Components and Equipment at those Facilities.

The above-referenced studies suggest that equipment leaks occur at facilities across the oil and natural gas sector and at a wide range of components and equipment at these facilities. We support EPA's proposal to require LDAR for a variety of potentially leaking components and

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[74] SwRI, "Methane Detectors Challenge Phase 1 Testing Report," prepared for EDF (December 9, 2014), *available at* https://www.edf.org/sites/default/files/content/mdc_phase_1_revised_report.pdf.

[75] For example, Colorado provides operators flexibility in determining what type of leak detection equipment to use. Operators may use an IR camera, Method 21, or "other Division approved instrument based monitoring device or method." (5 C.C.R. 1001-9, CO Reg. 7, § XVII.A.2). To date, the Division has approved one additional device, the Rebellion photonics camera. Wyoming allows for Method 21, an optical gas imaging instrument or other instrument-based technologies approved by the Air Quality Division.

equipment at facilities across the oil and natural gas sector. Below, we provide our recommendations for clarifying and expanding the scope of LDAR requirements to ensure that EPA's proposal adequately addresses facilities and equipment, which are sources of harmful fugitive emissions of air pollutants. In subsection i, we recommend that EPA clarify its affected source definitions to ensure that certain potentially high-emitting, centralized gathering facilities are not inadvertently excluded from the rule's LDAR requirements. In subsection ii, we urge EPA to include clearly within the scope of its LDAR requirements intermittent-bleed pneumatic devices. In subsections iii and iv, we recommend that EPA reevaluate and either eliminate or narrow two exemptions from LDAR requirements that EPA has proposed: one for wells that produce less than 15 barrels of oil equivalent per day (BOE/d), and the other for well sites that contain wellheads with no associated ancillary equipment.

1. EPA Should Ensure LDAR Requirements Apply Comprehensively to Gathering Facilities.

Regarding the scope of facilities required to be monitored under EPA's proposal, we support EPA's inclusion of facilities in the upstream and midstream segments, including: (1) oil and natural gas well sites; (2) compressor stations in the gathering and boosting and transmission and storage segments; and (3) natural gas processing plants. We are concerned, however, that EPA's proposal could exempt some potentially high-emitting gathering facilities, and urge EPA to ensure that the final LDAR provisions of the rule seamlessly apply to major facilities throughout the gathering segment.

Comprehensive and rigorous LDAR requirements are particularly important for the gathering segment, which recent studies show to be one of the most significant sources of emissions in the oil and gas sector. According to a recent measurement-based study by Colorado State University researchers, facilities in the gathering segment nationwide are estimated to emit approximately 1.7 million metric tons of methane per year—about eight times the GHGI's estimated emissions from gathering systems.[76] Infrared camera inspections at the gathering facilities found leaks at a substantial percentage of gas gathering facilities measured.[77]

We also know from prior studies that a substantial share of emissions from these facilities is likely attributable to fugitive leaks and improperly functioning equipment that can be addressed through regular instrument-based LDAR.[78]

EPA has proposed regulatory language that could have the unfortunate effect of exempting potentially high-emitting gathering facilities from the program. Under the proposed rule, LDAR requirements would apply to the "collection of fugitive emissions components" at both "well

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[76] Anthony J. Marchese et al., (2015), "Methane Emissions From United States Natural Gas Gathering and Processing," *Environ. Sci. Technol. 49*, **17**, 10718 at 10724 Fig. 4, *available at* http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02275 (comparing estimated gathering facility emissions of 1,697 Gg CH_4 per year to the annual Greenhouse Gas Inventory estimate of just 226 Gg).

[77] Underlying data analyzed in Marchese et al. described in Mitchell (2015) Supporting Information, S21, Table S6. The infrared study team noted the presence of vents or leaks at liquids storage tanks, dehydrators, compressors, pneumatics and other (leaks at pipeline, inlet separation/filtration, meters, etc.) Of these categories, "Other" consists solely of leaks, while the other categories consist of a combination of leaks and vents.

[78] Across all segments in the oil and gas sector, approximately 35 percent of total emissions are estimated to be associated with fugitives from aboveground sources. *See* note 2 *supra*.

sites" and "compressor stations" in the transmission and gathering segments. 80 Fed. Reg. at 56,664 (proposed 40 C.F.R. § 60.5365a(i)-(j)). "Well sites" are defined to include "production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad," as well as "centralized tank batteries" that collect liquids from wells not located at an individual well site. *Id.* at 56,697 (Proposed 40 C.F.R. § 60.5430a).As a result of these definitions, the proposed LDAR requirements can be interpreted *not* to apply to certain gathering facilities—in particular, centralized gathering facilities that are not "directly associated" with a well pad and that are not co-located with compressor stations or tank batteries that are expressly covered by the proposed rule.

This potential gap in coverage raises two concerns. First, recent field research indicates that there are some potentially high-emitting gathering facilities that are not associated with storage tanks or compressors. Specifically, a February 2015 study by Colorado State University examined methane emissions from 114 randomly selected gathering facilities in multiple states.[79] Of the facilities sampled, six consisted of sites that contained neither on-site compression nor storage vessels and would therefore potentially be excluded from EPA's proposed affected source definitions for LDAR.[80] These six facilities included dehydration and treatment equipment, and recorded throughput as high as 650 million standard cubic feet per day (MMSCF/d).[81] The emission rates from these six facilities averaged 0.65 percent of throughput (with a maximum emission rate of over 2 percent),%).[82] This is comparable to or higher than the emission rates for many of the gathering compressor stations examined in the study.[83] Moreover, the average emissions rate from these six facilities was 11.7 kg/hr – slightly higher than the average emission rate for the (larger) number of gathering compressor stations measured, which was 11.3 kg/hr.[84] Second, this gap in coverage could inadvertently incentivize owners of oil and gas facilities to deliberately develop gathering facilities in such a way as to avoid becoming affected sources. If this were to occur, a growing number of gathering facilities could become exempt from the LDAR requirements.

In order to ensure comprehensive coverage of LDAR requirements in the gathering segment and avoid such perverse incentives, we urge EPA to clarify in the final rule that all centralized gathering facilities are subject to LDAR requirements. This could be accomplished by amending the proposed definition of "well site" to explicitly include centralized gathering facilities that are associated with one or more well pads and that contain fugitive emissions components as defined in proposed 40 C.F.R. § 60.5430a.

2. EPA's Proposed LDAR Requirements Should Apply Comprehensively to both Components and Equipment at Affected Facilities.

[79] Mitchell (2015), at 3219.
[80] *See* Mitchell (2015), Supporting Information at S7 Table S1 (indicating facilities 110-115 were classified as either dehydration only (D) or dehydration/treatment (D/T)).
[81] *Id.* at S12, Table S2 (Facilities 110-115).
[82] *Id.* at S27, Table S7 (Facilities 110-115). These emissions include both fugitive leaks and equipment venting. See S21, Table S6 (Facilities 110-115). Infrared camera inspection of these facilities indicates that at four of the six sites, the emissions included leaks.
[83] *Id.* at S27, Table S7.
[84] *Id.* (comparing average rate for Facilities 110-115 to average emission rate for Facilities 1-34).

In addition to deploying LDAR at facilities across the oil and natural gas sector, it is important to ensure that operators comprehensively survey components and equipment at those affected facilities.

We support EPA's proposal to include both components and equipment in the definition of "fugitive emissions components" and note that sources like storage tank thief hatches and separator dump valves can be associated with significant emissions and should be part of leak inspection surveys.[85] Indeed, field observations in Colorado using infrared cameras and other methodologies indicate that substantial emissions from controlled storage tanks can occur when emissions bypass control devices and are allowed to escape through open thief hatches and pressure relief valves (*e.g.*, when pressurized liquids from the separator are dumped into the atmospheric tank).[86] Colorado now requires regular LDAR at new and existing storage vessels for this very reason.[87] The Texas Commission on Environmental Quality has also noted the importance of these types of improper emissions.[88] Recent studies of emissions from the gathering segment show substantial emissions from these sources, and underscore the importance of EPA's proposal including them within the scope of its LDAR requirements.[89]

EPA's proposed definition of "fugitive emissions components" does, however, exclude "devices that vent as part of normal operations," like "natural gas driven pneumatic controllers." We urge EPA to revise the definition of "fugitive emissions components" to include intermittent-bleed pneumatic controllers. Recent studies have shown that these devices can function improperly and produce significant emissions, and an LDAR program could effectively identify and eliminate this pollution.

Several recent scientific studies have shown that intermittent controllers, which are designed to vent only periodically when actuating, can instead function improperly, vent continuously, and produce substantial emissions. In particular:

- **Allen et al (2015).** As part of the Phase II UT study, an expert review of the controllers with highest emissions rates concluded that some of the high emissions were caused by repairable issues, and "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."[90]

- **City of Fort Worth Study.** The Fort Worth Study examined emissions from 489 intermittent-bleed pneumatic controllers, using IR cameras, Method 21, and a HiFlow

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[85] Brantley, H.L. et al., (2015) "Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements," *Environ. Sci. Technol.*, *48*, **24**, at 14508–14515 ("Brantley (2015)"), *available at* http://pubs.acs.org/doi/abs/10.1021/es503070q; *see also* Mitchell (2015), at 3219. *See also* Nobel Energy Consent Decree, at 1; EPA Compliance Alert 2015.
[86] *See* CAPCD Cost-Benefit, at 13.
[87] 5 C.C.R. 1001-9, §XVII.C.2.b.(ii)(d).
[88] Texas Commission on Environmental Quality, Presentation at National Academy of Sciences Workshop on Risks of Unconventional Shale Gas Development, May 30-31, 2013, at 15, *available at* http://sites.nationalacademies.org/cs/groups/dbassesite/documents/webpage/dbasse_083487.pdf.
[89] *E.g.,* "Substantial venting from liquids storage tanks was observed at 20% of gathering facilities. Emissions rates at these facilities were, on average, around four times the rates observed at similar facilities without substantial venting." Mitchell (2015), at 3219-3227.
[90] Allen (2015), at 633–640.

sampler for quantification. The study found that many of these controllers were emitting constantly and at very high rates, even though the devices were being used to operate separator dump valves and were not designed to emit in between actuations.[91] Average emission rates for the controllers in the Fort Worth Study were at a rate approaching the average emissions of a high-bleed pneumatic controller. According to the study authors, these emissions were frequently due to supposedly improperly functioning or failed controllers.[92]

- **British Columbia Study.** The Prasino study of pneumatic controller emissions in British Columbia also noted the potential for maintenance issues leading to abnormally high bleed rates.[93] Although the researchers did not identify a cause for these unexpectedly high emission rates, the results are consistent with the observation that maintenance and operational issues can lead to high emissions.

- **The Carbon Limits Study.** The Carbon Limits Report confirms these findings and concludes that LDAR programs may help to identify other improperly functioning devices like pneumatic controllers.[94]

As the Fort Worth Study suggests, and the Carbon Limits study confirms, the same methods used for leak detection at valves, connectors, and other leaking components and equipment at oil and gas facilities can be used to spot significant operational issues at pneumatic controllers. This is particularly true of intermittent-bleed controllers, where an OGI survey revealing continuous emissions from an intermittent controller can alert operators to the problem. Moreover, if a comprehensive LDAR program is already being implemented at a facility, the marginal cost of extending that program to intermittent-bleed pneumatic controllers would likely be very modest, especially if an operator uses an OGI (e.g., IR camera) or similar technology to detect leaks. Accordingly, we strongly urge EPA to finalize an LDAR program that addresses all potential sources of leaks and inadvertent venting, including intermittent-bleed controllers.

EPA could ensure these devices are monitored by revising the definition of "fugitive emissions component" to exclude only "devices that vent **continuously** as part of normal operations, such as **continuous** natural gas-driven pneumatic controllers."

3. EPA's Proposal to Exempt Wells Producing Less than 15 Barrels of Oil Equivalent Per Day is Arbitrary and Not Supported by the Record.

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[91] Fort Worth Study.

[92] *Id*. at 3-99 to 3-100. ("Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually.")

[93] The Prasino Group, *Determining bleed rates for pneumatic devices in British Columbia; Final Report*, (Dec. 18, 2013), at 19, *available at* http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/pneumatic-devices/prasino_pneumatic_ghg_ef_final_report.pdf. ("Certain controllers can have abnormally high bleed rates due to operations and maintenance; however, these bleed rates are representative of real world conditions and therefore were included in the analysis.").

[94] Carbon Limits, "Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras," (2014) at 12 fn 9, *available at* http://www.carbonlimits.no/PDF/Carbon_Limits_LDAR.pdf.

EPA has proposed to exclude from LDAR requirements wells that produce less than 15 BOE/d in the first month of production, which the agency considers low- producing wells. 80 Fed. Reg. at 56,639. This exclusion is arbitrary, lacks a rational explanation, and is not supported by the record.
EPA justifies this exemption on the grounds that "emissions at low producing wells are inherently low," "such well sites are generally owned and operated by small businesses," and LDAR requirements at these facilities could therefore impose hardship on small businesses. *Id*. The agency provides no evidence to support these assertions, though requests comment on each, including comment on different thresholds or other policy approaches that could secure reductions at these sites. *Id.*[95] Below, we include a table setting forth our analysis of new and existing wells that would be affected by this exemption. We also provide evidence demonstrating that each of the agency's three fundamental assumptions is flawed, then offer recommend improvements to EPA's proposed exclusion to ensure application of LDAR at these wells.

Lower Producing Wells Can Have Substantial Emissions. EPA sets forth its understanding that lower producing wells are "inherently" low-emitting, yet the Agency provides no evidence to support this assertion. In fact, there is some connection between production level and emissions—indeed, production levels serve as a cap on potential emissions. However, differences in production levels explain only a small portion of the differences in emissions among sites.[96] Table 2 below provides a breakdown of the new well completions and emissions from new wells associated with the 15 BOE/d threshold for both oil and gas wells. As is illustrated, 24 percent of all new well completions, and 20 percent of the total emissions associated with those wells, are excluded under the 15 BOE/d threshold and thus would be exempt from all Federal fugitive standards. Further, if both new and existing wells are considered, 76 percent of total wells and total emissions are excluded under the 15 BOE/d threshold.[97]

Table 2: New Well Counts and Emissions

[95] *See also* TSD, at 123; RIA, at 7-16.
[96] Zavala-Araiza, et al., (2015) "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," *Environ. Sci. Technol.,* 49, 13, at 8167, *available at* http://pubs.acs.org/doi/pdfplus/10.1021/acs.est.5b00133.
[97] Analysis conducted by EDF using 2013 data from 40 CFR Part 98 Subpart W reported data, DrillingInfo HPDI data, and the US EPA GHG Inventory.

New wells Emissions and Well Counts	Gas Wells				Oil Wells				Total	
	> 15 BOED	<= 15 BOED	% Breakdown		> 15 BOED	<= 15 BOED	% Breakdown		% Breakdown	
			> 15 BOED	<= 15 BOED			> 15 BOED	<= 15 BOED	> 15 BOED	<= 15 BOED
New Completions on Existing Wellpads (Mg CH4)	4,870	1,069	82%	18%	1,066	375	74%	26%	80%	20%
New Completions on New Wellpads (Mg CH4)	13,915	3,055	82%	18%	3,046	1,070	74%	26%	80%	20%
Single Wellhead New Completions (Mg CH4)	16,003	3,513	82%	18%	3,503	1,231	74%	26%	80%	20%
New Completions (well Counts)	7,422	1,669	82%	18%	21,511	7,607	74%	26%	76%	24%

Published research shows that these low producing wells can be responsible for substantial emissions. Zavala-Araiza, et al. performed an analysis illustrating how the probability of a production site being among the highest emitting sites does not increase uniformly with production volume.[98] Consequently, requiring LDAR only at sites above certain production levels would exempt sites with low production but potentially high fugitive emissions.[99]
The analysis performed by Zavala-Araiza, et al. identified significant emission reduction opportunities for the lower production cohorts. In this analysis, production sites in the Barnett Shale production region of Texas were classified into four production cohorts, with the two lower ones including wells that produce less than 10 Mcf/day and 10 to 100 Mcf/day, respectively. (For reference, 15 BOE/d is equal to roughly 87 Mcf/day.) These two cohorts accounted for 33 percent of total Barnett Shale emissions, with 76 percent of total emissions from these cohorts attributed to functional super emitters (defined here as sites with an excess of emissions related to avoidable operating conditions).[100]

The study reports measurements from a total of 75 wells (65 production sites) that would fall below the production threshold of less than 15 BOE/d. The average emission rate from these sites is 1.90 kg CH_4/h (18.4 short tons CH_4/ year), and 30 percent were classified as functional super-emitters, where their emissions represented between 1 percent and 100 percent of their production. The average rate from these facilities is higher than the central emission factor derived for all production cohorts by Zavala-Araiza, et al., which was 1.03 kg CH_4/h per production site (9.95 short tons/ year). It is also far higher than EPA's projection of emissions from a model well site, which the agency estimated to be about 4.4 tons per year.[101]
The results presented by Zavala-Araiza, et al. show that lower producing wells can have significant emissions. Based on the high proportional loss rates at those sites, LDAR could significantly reduce fugitive emissions at these facilities.

Fig. 3: Proportional Loss Rate (emissions as a percent of produced gas) Versus Absolute Methane Emissions (tons methane per year) for Wells Producing Less Than 15 BOE/d

[98] Zavala-Araiza (2015), at 8167−8174.
[99] *See id.*
[100] *Id.*
[101] *Id.*

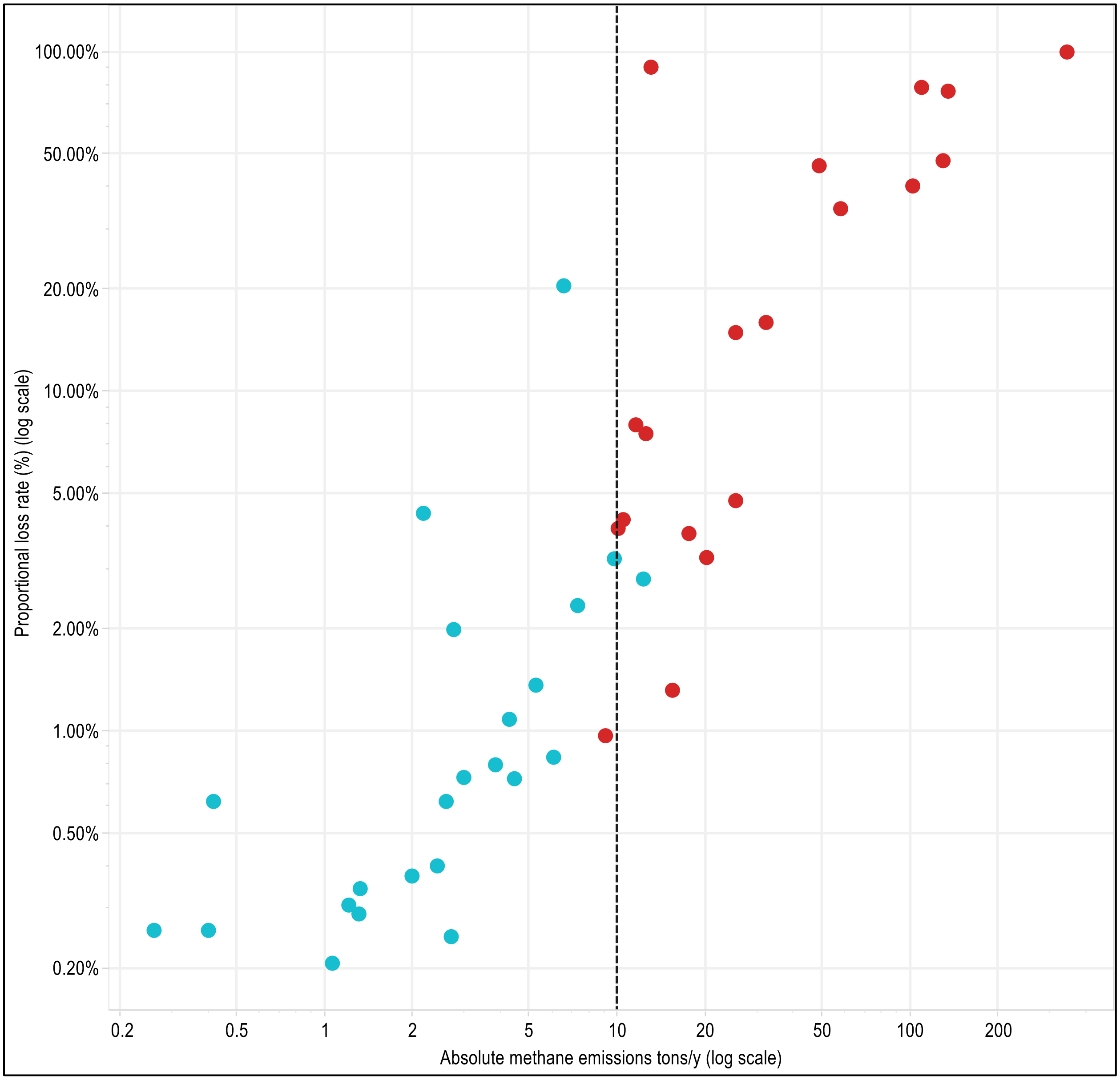

Figure 3 above shows measured production sites where production per well was less than 15 BOE/d. The x-axis shows absolute methane emissions in short tons per year, while the y-axis shows proportional loss rate (methane emissions divided by methane production). Red dots correspond to sites classified as functional super-emitters (Zavala-Araiza, et al.), meaning their emissions represent 1 percent to 100 percent of their production. The black dotted line represents the average emission factor determined by Zavala-Araiza, et al. for all the production sites (all production levels) in the Barnett Shale. The figure shows that many of the sites with production less than 15 BOE/d are classified as super-emitters and are, contrary to EPA's assumptions, associated with high absolute emissions. Clearly, with high emissions (12 of the well sites are classified as functional super-emitters and emit *over 5% of production*, an instrumental leak detection and repair program, such as with OGI, can readily reduce emissions from these sites.

Fig. 4: Proportional Loss Rate (emissions as a percent of produced gas) Versus Absolute Methane Emissions (tons methane per year) for Facilities and Functional Super-Emitters in Various Production Categories

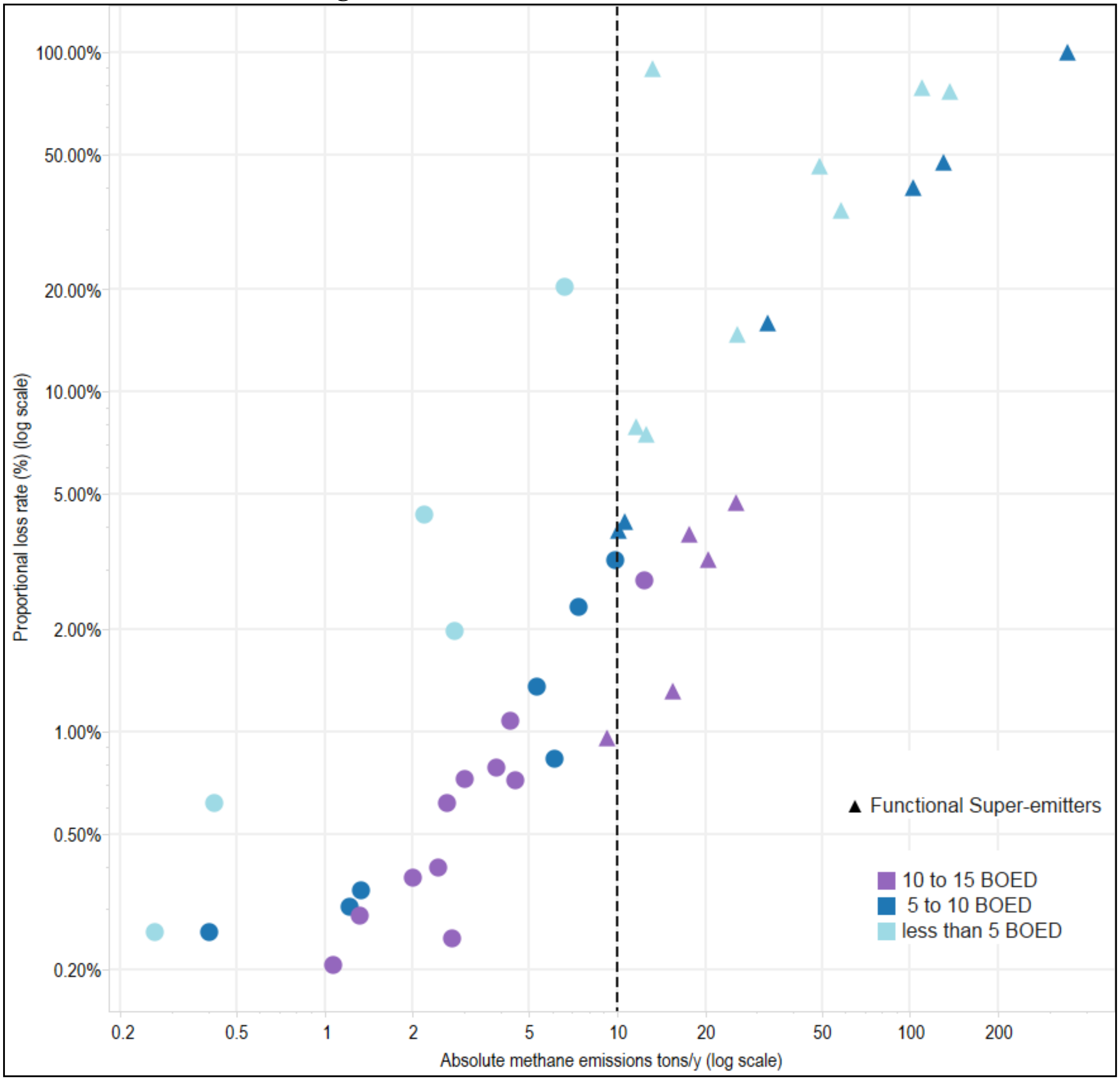

Figure 4 above also illustrates the distribution of super-emitters relative to production. As indicated, functional super-emitters are distributed across all production tiers, indicating no direct correlation between production and absolute emissions or between production and proportional loss rate. In fact, sites producing less than 5 BOE/d – much less than EPA's proposed threshold of 15 BOE/d – are some of the highest emitters in both percentage terms *and absolute terms.*

Lower-Producing Wells Are Owned by both Large and Small Producers. EPA assumes that exempted lower-producing wells are largely owned by small businesses. We examined data from the HPDI Database to evaluate this claim, analyzing wells above and below the 15 BOE/d threshold (as well as lower thresholds). We then examined ownership profiles of these wells, classifying wells owned by the top 100 oil and natural gas producers as well as other smaller producers. Importantly, this is a very conservative approximation of small-business ownership profile, as many of the producers that fall outside of the top 100 nonetheless have more than 500 employees, the threshold for small business status for oil and natural gas exploration / production. Moreover, even companies in the oil and gas sector with fewer than 500 employees can have significant revenues—sometimes in excess $1 billion annually.

Our analysis demonstrates that wells producing less than 15 BOE/d are owned by both large and small producers. In particular, major operators own approximately one third of such wells (35 percent of new gas wells and 29 percent of new oil wells).[102] Thus, EPA's assumption that small businesses own lower-producing wells belies the significant number that are *not* owned by small business.

Applying LDAR at Lower-Producing Wells Will Not Result in Hardship. We analyzed the economics of requiring semi-annual inspections at low producing wells by comparing the cost of LDAR to the total revenue produced from the single low-producing well. For this analysis, we used EPA's assumed cost of LDAR and calculated revenue assuming different oil and natural gas prices. We assumed three different levels of low-producing wells: the proposed 15 BOE/d level; a 10 BOE/d level; and a 5 BOE/d level. Tables 3 and 4 below set forth our results, showing that for all levels of low-producing wells, LDAR costs are a mere fraction of that well's annual revenue. Our estimates are also highly conservative, since it assumes that an operator only owns one low producing well, when operators are actually often likely to own a mix of higher- and lower-producing wells across which costs can be shared.

Table 3: LDAR Cost as a Percentage of Revenue at Six Price Points for Crude Oil

[102] Analysis conducted by EDF using 2013 data from 40 CFR Part 98 Subpart W reported data, DrillingInfo HPDI data, and the US EPA GHG Inventory.

	Annual Production (BOE/yr)	Crude Oil Spot Price ($/bbl)					
		$40.00	$50.00	$60.00	$70.00	$80.00	$100.00
		ANNUAL REVENUE PER WELL[1]					
Oil well 15 BOE/day	5,475.0	$175,200	$219,000	$262,800	$306,600	$350,400	$438,000
Oil Well 10 BOE/day	3,650.0	$116,800	$146,000	$175,200	$204,400	$233,600	$292,000
Oil Well 5 BOE/day	1,825.0	$58,400	$73,000	$87,600	$102,200	$116,800	$146,000

	LDAR COST AS % OF REVENUE[2]					
Oil well 15 BOE/day	0.91%	0.73%	0.61%	0.52%	0.46%	0.37%
Oil Well 10 BOE/day	1.37%	1.10%	0.91%	0.78%	0.68%	0.55%
Oil Well 5 BOE/day	2.74%	2.19%	1.83%	1.56%	1.37%	1.10%

[1] Assumes 20% royalties
[2] Annual cost of OGI semi-annual LDAR: $1,599 per well (net of methane credits), EPA TSD Table 5-15

Table 4: LDAR Cost as a Percentage of Revenue at Five Price Points for Natural Gas

	Average Annual Production[1] (mill SCF/yr)	Well Head NG Price ($/1000 CF)				
		$2.50	$3.00	$3.50	$4.00	$4.50
		ANNUAL REVENUE PER WELL[2]				
Low Producing Wells (<15 BOE/day)	23.1	$46,138	$55,365	$64,593	$73,820	$83,048
Other Wells	61.2	$122,444	$146,933	$171,422	$195,911	$220,400

	LDAR COST AS % OF REVENUE[3]				
Low Producing Wells (<15 BOE/day)	3.47%	2.89%	2.48%	2.17%	1.93%
Other Wells	1.31%	1.09%	0.93%	0.82%	0.73%

[1] Based on data in RIA Table 2-5
[2] Assumes 20% royalties
[3] Annual cost of OGI semi-annual LDAR: $1,599 per well (net of methane credits), EPA TSD Table 5-15

Policy Recommendations. Given the potentially significant emissions from these sources, we recommend that EPA eliminate the 15 BOE/d exclusion. As shown above, these smaller producing wells can be the source of very harmful emissions. If EPA concludes that LDAR inspections, at the frequency generally applied to well sites (i.e., semi-annual in EPA's Proposal, or quarterly as we show would be justified, below) is not appropriate for lower emitting wells, EPA should apply less frequent monitoring requirements to these wells instead of exempting them entirely. To the extent EPA moves forward with tiered monitoring requirements (which we address more fully below), such tiering could help to ensure these lower producing wells do, in fact, perform, LDAR. In the Colorado regime, for instance, even the smallest wells are required to perform LDAR, and EPA should at least apply a similarly calibrated approach.

4. EPA's Proposed Christmas Tree / Single Well Exemption

EPA also proposes to exclude from LDAR well sites that contain "one or more wellheads" and no associated equipment. 80 Fed. Reg. at 56,612. EPA justifies this exclusion with its belief that such well sites have low emissions due to the low number of components existing on wellheads that are not associated with production equipment. *Id*. at 56,611.

If EPA retains the wellhead exemption, it should narrow it to apply to single wellheads only. Well sites that contain more than one wellhead must not be exempt, since there is no limit to the number of components (and therefore sources of fugitive emissions) that could exist at such sites, even if no associated equipment is present. Even without the addition of associated equipment, a well site with multiple single wellheads could be a significant source of emissions, in particular if there is a very large leak coming from one of the wellheads.[103] If the agency retains this exemption, it must therefore narrow it to sites with just one wellhead.

Furthermore, if EPA retains the wellhead exemption, the agency must ensure that it is structured in a way that prevents operators from separating wellheads from ancillary equipment, such as separators and dehydrators, in order to exempt *all* of the equipment from fugitive standards. Operators could conceivably locate separators and dehydrators at separate locations from wellheads. If no tanks or compressors were present at these sites, operators may interpret the standards, as proposed, as exempting the separators and dehydrators, in addition to the wellheads. If EPA retains this exemption, the Agency must add language to the standards explicitly applying the fugitive standards to any separators, heaters, dehydrators, etc., associated with the well, even if located at a site with no wellheads or tanks.

C. EPA Should Strengthen the Frequency of LDAR in the Final Rule and Remove Frequency Adjustment Based on Percent of Leaking Components.

Given the geographic and temporal unpredictability of leaking equipment, one of the most important aspects of such a program is the frequency with which operators inspect facilities. EPA has proposed semi-annual leak inspection surveys, with provisions to allow operators to adjust frequency based on the percentage of leaking components found onsite. These provisions fall far short of what is necessary to protect public health and the environment, and lag behind what leading states and companies have already demonstrated in practice. Accordingly, EPA's proposed requirements do not reflect a BSER determination in accordance with section 111, and the agency must strengthen the baseline frequency of inspections in the final rule and remove the proposed step-down provisions.

In subsections i and ii, we outline the flaws in EPA's rationale for rejecting more frequent monitoring at well sites and compressor stations and for adopting frequency step-downs. In subsection iii, we summarize state and industry experience showing that more frequent

[103] Zavala-Araiza (2015), at 8176-8174.

monitoring is cost-effective. In subsection iv, we provide our recommendations to EPA, summarized as follows:

- EPA must require quarterly LDAR at well sites and compressor stations, or alternatively, adopt a tiered monitoring approach for well sites along the lines reflected in the Colorado rule.

- EPA must eliminate provisions allowing operators to reduce inspection frequency based on the percentage of leaking components.

1. EPA's Rationale for Rejecting More Frequent Monitoring at Well Sites and Compressor Stations is Flawed.

EPA has declined to adopt more frequent monitoring at well sites on the grounds that quarterly OGI inspections are not cost-effective for reducing VOCs and methane. 80 Fed. Reg. at 56,636. Although the agency's own analysis shows quarterly inspections to be substantially more cost-effective at compressor stations than other sectors, EPA nonetheless proposes less frequent surveys for these facilities based on its concerns with inspection equipment availability and small business impacts at these facilities. 80 Fed. Reg. at 56,637. Both of these rationales are flawed, and the agency should strengthen frequency requirements for these sources in the final rule.

Well Sites. EPA recognizes that quarterly LDAR is more effective than less frequent inspections, *id*. at 56,635, and likewise estimates LDAR survey costs that are roughly in line with past analyses, *id.* at 56,636. The agency, however, estimates baseline emissions from its model well site that are substantially lower than other analyses. These unrealistically low baseline emissions substantially understate the benefits of LDAR and reach the incorrect conclusion that quarterly LDAR is not cost-effective. Table 5 below compares EPA's estimate to several other recent studies.

Table 5: Comparison of EPA's Model Facility Emissions with Other Studies' Models[104]

[104] Fort Worth Study; CAPCD Cost-Benefit; Zavala-Araiza (2015).

Source	Well Heads per Site	Potential Leak Sources		Average CH4 Emissions (ton/yr)			Notes	
		per site	per well head	per site	per well head	per 100 potential leak sources		
EPA NSPS 2015 Model Facility	2.0	548.0	274.0	4.54	2.27	0.828	GIS analysis for well heads per site; 1996 GRI study for component counts per site & emission rates per component	
Ft Worth Study	3.0	1826.0	608.7	32.3	10.77	1.769	TOTAL	Actual well-head and equipment counts, and leak measurements, for 375 gas well sites within city limits of Ft Worth, TX. More than 50% of leaking methane was from site tanks
				15.37	5.12	0.842	NON-TANK	
Colorado AQCC Cost/Benefit Analysis	NOT REPORTED	1464.0	NOT REPORTED	6.0	UNKNOWN	0.41	NAA	Component counts per "well production facility" based on "limited data". Numbers not reported, but inferred from reported facility total inspeciton time and stated assumptions about inspection time per component.
	NOT REPORTED	732.0	NOT REPORTED	6.5	UNKNOWN	0.89	REST OF STATE	Uncontrolled emission based on "reported component counts and standard emission factors." Emissions converted from methane-ethane assuming 86.1% by weight methane
EDF Barnett	1.9	NOT REPORTED	NOT REPORTED	17	8.94	UNKNOWN	The Barnett synthesis emission factor was derived from site-level emission measurements. It would include all components inside production sites would potentially emit. Even though this study did not look at the specific components within sites that would cause high emissions, a previous study (Zavala-Araiza et al., 2015 [Functional –Super-emitters]) looked at site-level data in the Barnett Shale and classified them based on their proportional loss rate (methane emitted relative to their production) defining functional super-emitters: "as sites with high proportional loss rates due to excess of emissions resulting from abnormal or otherwise avoidable operating conditions, such as malfunctioning equipment."	

EPA's model well site underestimates emissions in two important ways. First, the agency does not estimate fugitive emissions attributable to key sources that expressly fall within the LDAR requirements. EPA recognizes as much, noting that "[s]ince we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of fugitive emissions components that would typically be found at a well site." 80 Fed. Reg. at 56,635. Indeed, EPA defines "fugitive emissions component" subject to LDAR requirements as including "*any component* that has the potential to emit fugitive emissions" and specifically enumerates certain components like "valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters." *Id*. at 56,638.

This definition expressly includes important fugitive sources associated with tanks—like thief hatches and separator dump valves—but EPA's model well site does not attribute any emissions to these sources, which can be significant:

- In the City of Fort Worth study, referenced in the above table, 50 percent of emissions are attributable to storage tanks.
- The Gathering and Boosting study found "[s]ubstantial venting from liquids storage tanks was observed at 20% of gathering facilities. Emissions rates at these facilities were, on

average, around four times the rates observed at similar facilities without substantial venting."

- The Brantley Study identified open thief hatches at storage tanks as a substantial source of emissions.[105]
- EPA's 2015 settlement agreement with Noble Energy and compliance alert on storage vessel emissions[106] also recognize that substantial emissions can be associated with open thief hatches on storage tanks and that deploying OGI cameras can reduce these emissions.

Second, EPA has determined cost-effectiveness based on a model facility that is far smaller (and lower-emitting) than many new well pads currently being developed. EPA recognizes that its methodology for estimating the average number of wells on a new well pad may have this effect, noting that "industry and state regulatory trends indicate that well drilling will likely become increasingly concentrated on sites, potentially leading to an increase in the average number of wells per well site."[107] This problem is compounded by EPA's use of GRI data from 1996 to develop average site-level component and emissions profiles, both of which are lower than recent studies suggest and fail to account for large super-emitters. Additionally, in developing a model facility, EPA's methodology fails to exclude the facilities the agency has proposed to exempt, which results in an estimate that is further biased on the low end.[108]

Several of the studies referenced in Table 5 above suggest average facilities that are larger, more complex, and higher emitting than EPA's model facility. Technical analyses underpinning Colorado's standards, along with data collected as part of the Fort Worth study, reflect larger, more complex facilities. This translates into baseline emissions for Colorado's analysis that are nearly 50 percent greater than EPA's model facility and average emissions from the Fort Worth dataset that are almost 4 times greater (excluding tank emissions).
Taken together, EPA's exclusion of key emissions sources and development of a small model facility yield a substantial underestimation of facility-level emissions, which, in turn, generate cost-effectiveness numbers that fail to recognize full benefits of performing more frequent LDAR.

Compressor Stations. EPA's cost-effectiveness estimates for LDAR at compressor stations are more aligned with previous analyses and demonstrate that more frequent, quarterly LDAR is cost-effective at these facilities. Nonetheless, EPA proposes semi-annual monitoring on the grounds that more frequent monitoring may constrain the availability of survey contractors, which may, in turn, adversely affect small businesses. 80 Fed. Reg. at 56,641. EPA cites the same rationale as a basis for its alternative proposal to require annual monitoring at well sites. *Id.* at 56,637.
EPA's rationale is flawed. Indeed, the agency's proposal is based on the premise (lacking factual support) that demand for LDAR contractors and equipment will outpace supply, leading to higher costs and adverse impacts for small businesses. However, prior experience and data suggest the opposite to be true: technology providers can quickly and efficiently respond to

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[105] Brantley (2015), at 14508–14515.
[106] Noble Energy Consent Decree, at 1; EPA Compliance Alert 2015.
[107] TSD, at 54.
[108] TSD, at 47.

signals created by clean air standards. Indeed, this has been true where standards have forced *development* of new technologies,[109] and is certainly the case where these technologies already exist and must simply be deployed more broadly.

In addition to this time-tested reality, EPA's rationale ignores circumstances related to these particular sources. With respect to compressor stations, EPA's TSD projects that, in 2020, 259 new gathering and boosting stations, six new transmission stations, and 15 new storage stations will be subject to the compressor station LDAR requirements.[110] This extremely small number of new sources is unlikely to drive any imbalance between supply and demand.

This is especially true given that some compressor stations in these segments are already deploying leak detection technology to comply with existing state and federal standards. Indeed, Colorado requires LDAR at new and existing gathering and boosting compressor stations, while EPA's Reporting Rule requires new and existing transmission compressor stations and underground and LNG storage facilities to undertake annual leak surveys using OGI and other technologies. *See* 40 C.F.R. §98.232(e)(7), §98.232(f)(5), §98.232(g)(3), and §98.233(q).[111] Colorado has projected that its standards would apply to 200 compressor stations,[112] and EPA's most recent Reporting Rule data suggest that over 300 facilities completed such surveys.[113] Pennsylvania has also required quarterly LDAR using OGI at gas processing plants and compressor stations since 2013.[114] It is simply erroneous to suggest that quarterly inspections at approximately 300 new facilities—or 1,200 new inspections—could not be completed in light of the breadth of sources already deploying these technologies. Moreover, though EPA projects a greater number of well sites will be subject to new LDAR standards, as discussed above, Colorado, Pennsylvania, Utah, Wyoming, and Ohio have had LDAR requirements in place for some time, and there has been no evidence of supply issues or adverse impacts to small businesses, including in states or areas where LDAR is required more often than semi-annually.

Finally, even if the agency receives rigorous, quantitative data suggesting that limited contractor availability may impact small businesses, it is nonetheless arbitrary for EPA to respond to these concerns by weakening clean air standards for *all* sources and in perpetuity. Indeed, in numerous other circumstances, including in recent oil and natural gas sector rulemakings, EPA has retained rigorous clean air standards, but phased those standards in to ensure adequate availability of pollution control measures. *See, e.g.,* Oil and Natural Gas Sector: New Source Performance

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[109] *See, e.g.*, David Gerard and Lester B. Lave, *Implementing technology-forcing policies: The 1970 Clean Air Act Amendments and the introduction of advanced automotive emissions controls in the United States*, 72 Technological Forecasting and Social Change 761 (2005), *available at* http://repository.cmu.edu/tepper/1356/(describing how EPA standards under section 202 resulted in the development and proliferation of the catalytic converter in 1975 and the three-way catalyst in 1981).
[110] TSD, at 65.
[111] We note that EPA has failed to consider the fact that operators of these facilities are already performing leak detection inspections, on an annual basis, at gas processing plants and transmission and storage compressor stations, as it has estimated the additional costs of the current proposal. EPA should have deducted the costs of one inspection per year for these facilities from their cost estimates, since those inspections are already occurring.
[112] CAPCD Cost-Benefit, at 22.
[113] EPA, GHGRP Industry Profiles: Petroleum and Natural Gas Systems, at 26, *available at* http://www2.epa.gov/sites/production/files/2015-11/documents/subpart_w_2014_data_summary_10-12-15_508_km.pdf.

Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule, 77 Fed Reg. 49,498, 49,513 (August 16, 2012), codified at 40 CFR Parts 60 and 63 (creating a one year phase-in period for storage vessel controls, pneumatic controllers, and RECs). At most, a limited phase-in may be appropriate here, and only if substantiated by rigorous technical information. Accordingly, as we describe below, EPA must strengthen frequency requirements for both compressor stations and well sites.

2. EPA's Rationale for Adopting Frequency Step-Downs Is Arbitrary and Not Supported by the Record.

In addition to proposing baseline, semi-annual monitoring requirements—which, as we describe above, would be less stringent than most existing state programs—EPA has further proposed to allow operators to adjust site monitoring frequency based on the percentage of leaking components found during a survey. In particular, the agency has proposed to allow sites to perform less-frequent annual inspections if, in two successive surveys, operators find less than 1 percent of components leaking. 80 Fed. Reg. at 56,637. Conversely, if more than 3 percent of components are leaking, operators would have to monitor quarterly. *Id*. The agency's rationale suggests that the proposal is meant to reward operators for achieving low emissions.
While well-designed policy incentives can enhance emissions performance, EPA's proposed frequency adjustments are arbitrary, misalign incentives for operators, and are almost entirely divorced from a facility's emissions performance. Indeed, they reward facilities with potentially substantial emissions while applying more rigorous standards to sources that may be more modest polluters.

EPA's proposal creates perverse incentives by rewarding operators for failing to identify harmful leaks. This is not a hypothetical concern. A 2007 report by EPA found "significant widespread non-compliance with [LDAR] regulations" at petroleum refineries and other facilities.[115] EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions."[116] The report recommends that "[t]o ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time," companies should monitor more frequently.[117] Instead, EPA should establish a rigorous baseline and reward operators for finding leaks more quickly and accurately—maximizing environmental benefits while minimizing costs. In subsection [F], below, we recommend an innovation pathway that could help to better align these incentives.

Furthermore, EPA's proposed metric for determining adjusted frequency—the percentage of leaking components— is not an accurate predictor of a facility's emissions performance. At a conceptual level, if emissions from leaking components were homogenously distributed, the percentage of components leaking at a facility would be a good indicator of facility-level emissions. However, there is overwhelming evidence that leak emissions follow a skewed, highly-heterogeneous distribution, with a relatively few number of sources accounting for a large

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[115] U.S. EPA, "Leak Detection and Repair: A Best Practice Guide," October 2007, at1, *available at* http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf.
[116] *Id.* at 23.
[117] *Ibid*.

portion of emissions. See for example Figure 1 *supra.* Figure 5 below depicts one such distribution taken from Allen *et al.* (2013).[118] In such circumstances, the percentage of leaking components will not accurately reflect emissions and should not be used to determine the frequency of LDAR survey requirements.

We empirically examined the effects of EPA's proposed 1 and 3 percent thresholds using data from the City of Fort Worth Study Air Quality Study,[119] which includes both component level emissions information and site-level data. Figures 5 and 6 below show the results of this analysis. Figure 5 compares site-level emissions to the percentage of leaking components and demonstrates that the individual sites with the highest emissions fall below EPA's proposed 1 percent threshold. Figure 6 aggregates site-level emissions at each of these thresholds. Sites with less than 1 percent leaking components constituted over half of total emissions and over half of all sites. Conversely, there were no high-emitting sites with greater than 3 percent of their components leaking, and sites above a 3 percent threshold accounted for a small percentage of total emissions.

Figure 5: Site Methane Emissions (lb per year) Versus Percent Leaking Components

[118] Allen (2013). Indeed, EPA recognized the skewed distribution of leaks in the development of the Alternative Work Practice for Method 21, which acknowledged that "most emissions are from equipment with larger leaks" and cited evidence that 95% of emissions from equipment leaks can be attributed to just 5% of the leaking components.[118] Similarly, a 2007 field study at an ExxonMobil chemical manufacturing facility found that the one percent of leaking components with the highest emissions had aggregate emissions equal to or greater than those from the 95% of the components with the lowest emissions.[118] The study also reported that these large leaks (defined as leaks monitored at over 1,000 parts per million (ppm)) released on average 250 times more methane than small leaks.[118]

[119] Fort Worth Study.

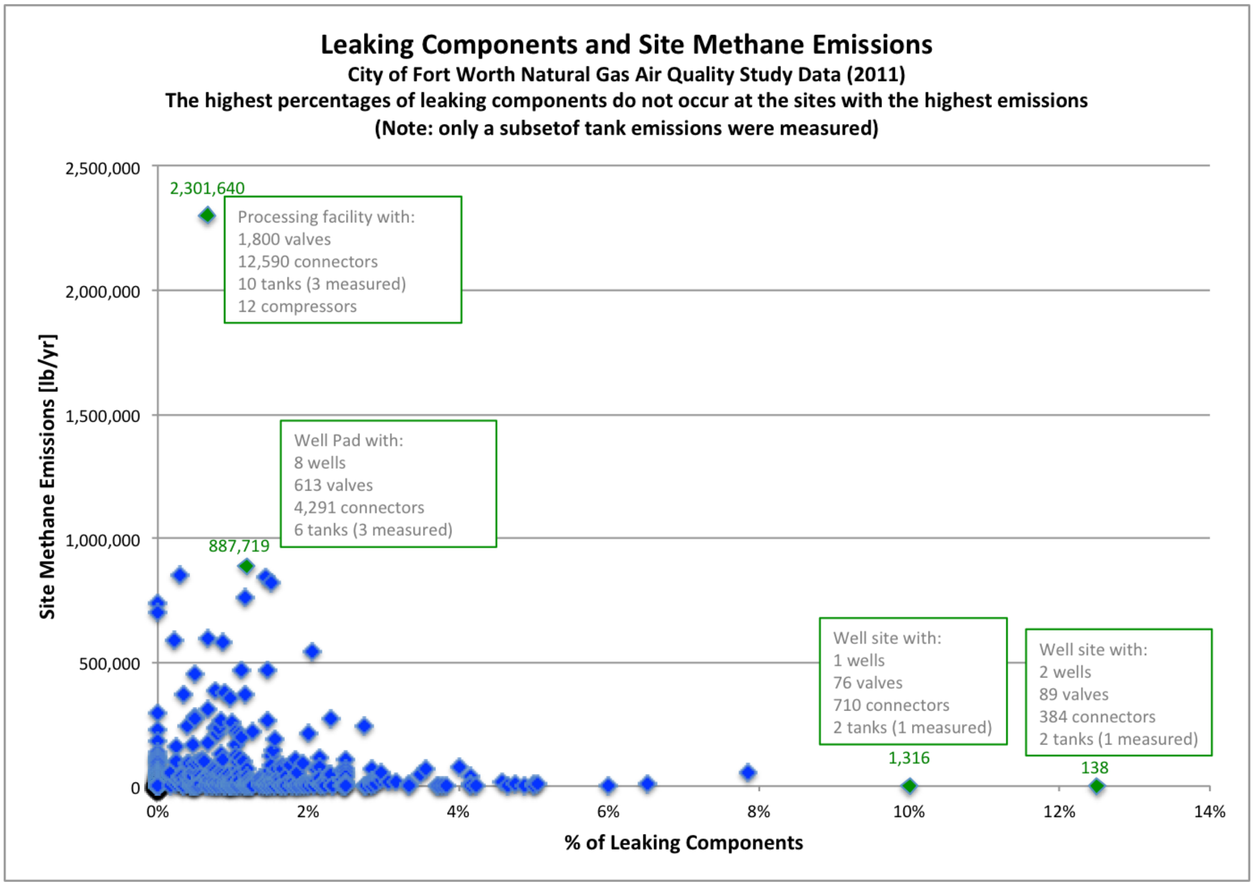
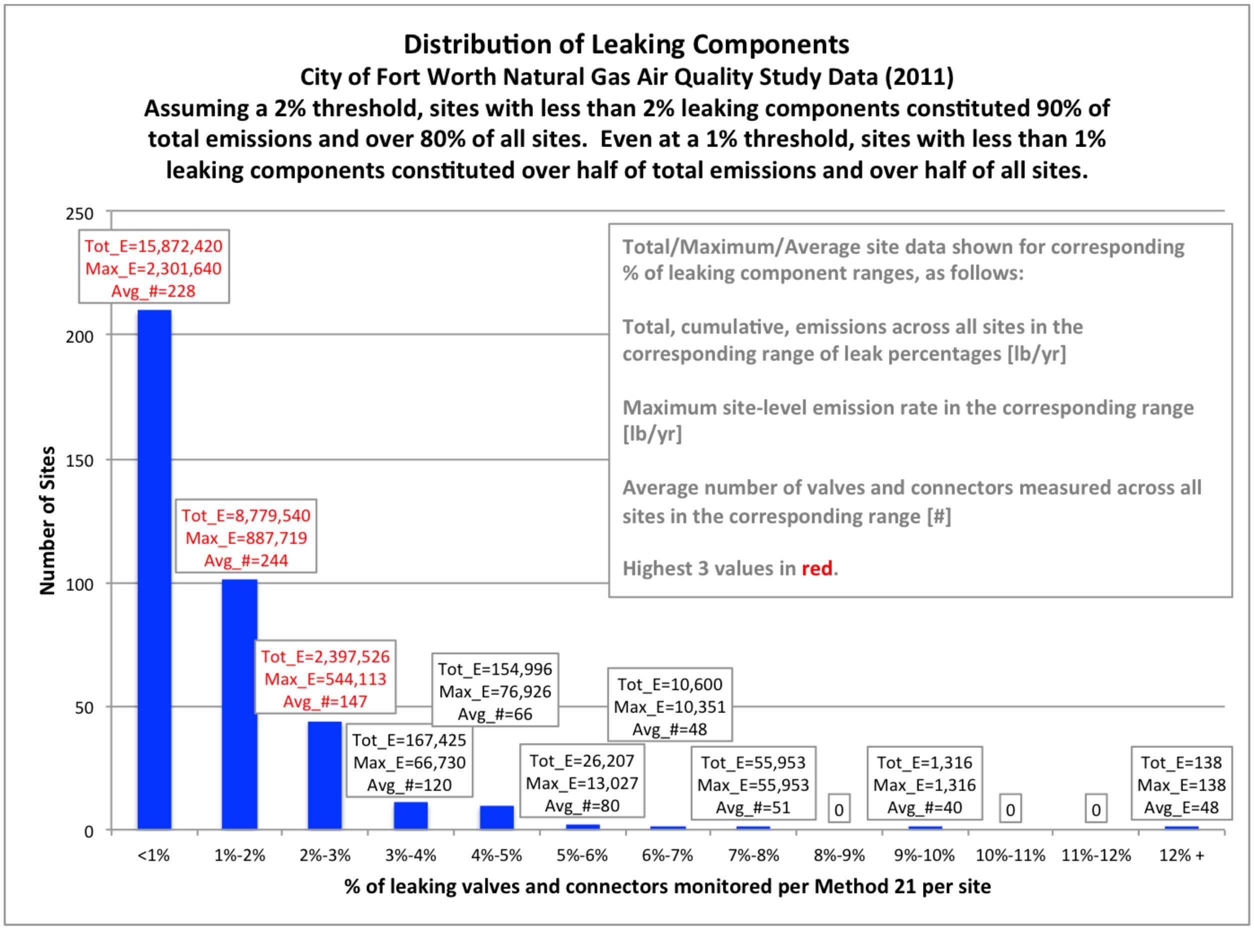


Figure 6: Number of Sites versus Percent of Leaking Valves and Connectors Monitored per Site (Method 21)



Data from operators collected as part of Colorado's LDAR program further support a fixed inspection requirement. Colorado's approach requires operators to inspect for leaks at all but the smallest sites on a fixed annual, quarterly, or monthly basis (depending on the facility's tanks emission potential). 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014). Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to Encana, "[our] experience shows leaks continued to be detected well into the established LDAR program."[120] Encana's data shows that while the largest reductions in VOC emissions occur in the first year of an LDAR program, significant emission reductions are still being realized in subsequent years of the LDAR program – because leaks re-occur at facilities.[121] This pattern was independently confirmed in supplementary analysis carried out by Carbon Limits on leak inspection data from a number of well production facilities and compressor stations.[122] Carbon Limits found that inspectors

[120] Ex. TA4, Rebuttal Statement of Encana Oil and Gas (USA) Inc., Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3, 7, and 9, at 10.
[121] *Id*. at 10-11.

I. [122] Colorado Department of Public Health and Environment, Index of /apc/aqcc/Oil & Gas 021914-022314/REBUTTAL STATEMENTS, EXHIBITS & ALT PROPOSAL REVISIONS/Conservation Group. Supplemental Testimony of David McCabe, at734-

continued to find leaks in repeat inspections on the same facility. Additionally, Carbon Limits found that the cost-effectiveness of the leak inspections, expressed in dollars per metric ton of VOC abatement, did not significantly rise over several years after regulations were put in place requiring LDAR at facilities in Alberta.

We strongly recommend that EPA remove provisions allowing operators to reduce frequency based on the percentage of leaking components identified in prior surveys. If the agency retains some provisions allowing frequency adjustment, those thresholds must be tied to emissions intensity. In addition to requiring operators to conduct leak surveys, the agency must require operators to accurately quantify site-level emissions in order to qualify a site for reduced-frequency inspections. While this would begin to address the disconnect between the metric for changing the frequency of inspections and actual emissions, we do not recommend that EPA take this approach. Indeed, even if emissions had been accurately quantified by EPA, studies suggest that past emissions are not a good predictor of future emissions given the prominent role that improperly functioning equipment, poorly maintained equipment, and other random events play in overall emissions. Facilities with low emissions during one survey may nonetheless experience such an event in the future, and less frequent monitoring at these sites would delay repairs to end these important and harmful emissions. Accordingly, we recommend EPA finalize LDAR standards based on fixed frequencies.

3. States, Industry Experience, and Independent Assessment Suggests that Frequent LDAR is Cost-Effective.

Indeed, states, industry evaluations, and independent assessment have found quarterly (or more frequent) LDAR to be highly cost-effective, and have not adopted skip monitoring provisions. Table 6 below sets forth some of these estimates, all of which are several times lower than EPA's estimate for quarterly LDAR in the TSD. Figure 7 shows how EPA's estimate compares to these estimates.

Table 6: Cost Effectiveness Estimates for Quarterly and More Frequent LDAR

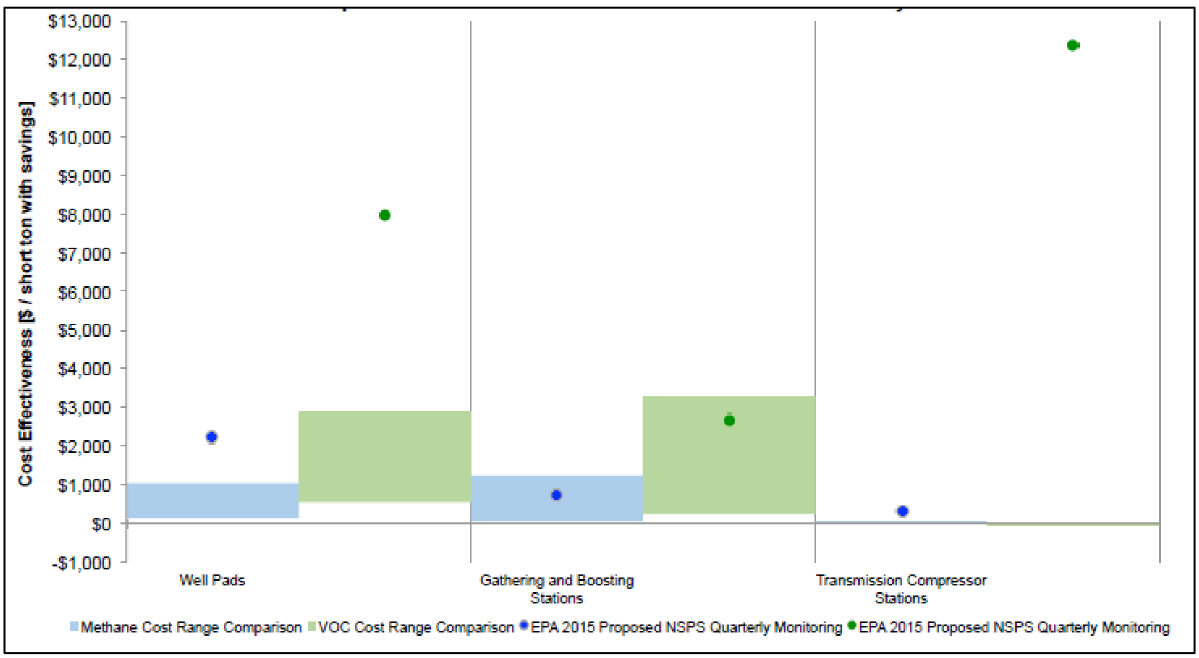
Source	Frequency	Pollutant	Cost-Effectiveness

736, *available at* ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Conservation%20Group/Conservation%20Groups%20-%20REB%20Exhibits.pdf.

State of Colorado[123]	Tiered (one-time through monthly)	Methane + ethane	$805/short ton (Well Sites) $474/short ton (Compressor Stations)
ICF International (2014)[124]	Quarterly	Methane	$133/metric ton (Well Sites) $48/metric ton (Gathering Compressor Stations) $114/metric ton (Transmission Compressor Stations)
Noble (CO Rulemaking)[125]	Tiered estimate	VOCs	$50-380/ton

Figure 7, below, illustrates the LDAR cost-effectiveness figures for quarterly LDAR per the 2015 proposed NSPS[126] relative to the cost ranges for quarterly LDAR as calculated by various other sources.[127] As shown, many of the costs assumed by the proposed standard are much higher than other estimates.

Fig. 7: EPA 2015 Proposed NSPS for Methane and VOC Cost Effectiveness of LDAR for Fugitive Emissions from Equipment Leaks Compared to Other Estimates



Frequent LDAR is supported by industry experience. Jonah Energy—an operator in the Upper Green River Basin in Wyoming— has expressed its support of at least quarterly

[123] CAPCD Cost-Benefit, at 27-28.
[124] ICF (2014), at 3-12.
[125] Ex. TA6, Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the Matter of Proposed Revisions to Regulation Number 3, Parts A, B, and C, Regulation Number 6, part A, and Regulation Number 7 Before the Colorado Air Quality Control Commission, at 7.
[126] EPA 2015 Proposed NSPS: Option 3 Quarterly Monitoring Single Pollutant Cost Effectiveness Estimates from RIA, *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_prop_ria_081815.pdf.
[127] ICF (2014), CATF et al. (2015), CDPHE (2014), EDF Leak Response, Carbon Limits 2014.

instrument-based inspections,[128] noting that it already complies with the proposal because "each month, Jonah Energy conducts infrared camera surveys using a forward-looking infrared camera ("FLIR") camera at each of our production facility locations."[129] According to Jonah, "[b]ased on a market value of natural gas of $4/MMBtu, the estimated gas savings from the repair of leaks identified exceeded the labor and material cost of repairing the identified leaks" while also significantly reducing pollution.[130] Jonah's experience that gas savings from repairs often exceed the cost of performing repairs to identified leaks is also borne out by the Carbon Limits report[131] and analysis carried out by Colorado.[132]

In addition, several companies that engaged in the development of Colorado's regulations provided evidence that frequent LDAR is cost-effective. In particular, Noble estimated the cost-effectiveness of Colorado's tiered program at "between approximately $50/ton and $380/ton VOC removed" at well production facilities.[133]

State regulators have established that frequent LDAR is feasible and cost-effective. Currently, five major oil and natural gas producing states require quarterly monitoring at oil and gas facilities—Colorado, Ohio, Pennsylvania, Wyoming and Utah. California has also proposed LDAR standards at new and existing sources statewide that, if adopted, would require quarterly LDAR using OGI instruments. In addition, four air districts in Southern California already have existing inspection and maintenance requirements aimed at detecting non-methane hydrocarbon leaks, each requiring quarterly inspections as a baseline.[134]

Colorado has adopted comprehensive LDAR requirements to reduce hydrocarbon leaks—consisting of methane as well as other organic compounds— at compressor stations, well sites, and storage tank batteries. Colorado's rule includes tiered frequency requirements based on the potential to emit VOCs, including inspection frequencies ranging from one time at the smallest facilities to monthly at the largest facilities. Mid-sized facilities are required to undertake inspections on a quarterly basis. 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb.

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[128] Jonah Energy stated: "We support the [recent Wyoming rule for existing sources in the UGRB], as proposed, with some minor suggested changes [to the proposed tank requirements] outlined below." Ex. TA5, Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Permit by Rule for Existing Sources (April 13, 2015).

[129] *Id*.

[130] Ex. TA2, Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Existing Source Regulations (Dec. 10, 2014).

[131] Carbon Limits 2014, at 16.

[132] Colorado Air Pollution Control Division used an entirely different method than Carbon Limits to predict that almost 80 percent of repair costs for well facilities will be covered by the value of conserved gas. *See* Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) at Table 30.

[133] Ex. TA6, Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the Matter of Proposed Revisions to Regulation Number 3, Parts A, B, and C, Regulation Number 6, part A, and Regulation Number 7 Before the Colorado Air Quality Control Commission, at 7.

[134] San Joaquin Valley Air Pollution Control District R. 4409 (2005); South Coast Air Quality Management District R. 1173 (1989); Santa Barbara County Air Pollution Control District R. 331 (1991); Ventura County Air Pollution Control District R.74.10 (1989).

24, 2014).[135] As a weighted average across all facilities, Colorado determined that its approach resulted in approximately 4.7 inspections per year.[136] Colorado's rule demonstrated the cost-effectiveness of quarterly inspections: for mid-sized compressor stations, the abatement cost was calculated at $746/metric ton of methane, and for well site inspections, the cost was $831/metric ton of methane.[137] As a whole, Colorado's tiered inspection frequency was likewise highly cost-effective, achieving emission reductions estimated at $1,259/ ton of VOC and $805/ton of methane/ethane at well sites[138] and $994/ton of VOCs and $474/ton of methane/ethane at compressor stations.[139]

Other states have similarly adopted programs with quarterly monitoring requirements:

- Wyoming. Wyoming requires quarterly instrument-based inspections at all new and modified well sites in its Upper Green River Basin with the potential to emit four tons of volatile organic compounds from fugitive components.[140] The state recently finalized the same requirements for existing well sites and compressor stations in the Basin.[141] Comments submitted in support of these requirements suggest that these requirements are highly cost-effective.[142]
- Ohio. Ohio requires quarterly inspections for leaks at unconventional well sites, using either a FLIR camera or Method 21 compliant analyzer.[143]
- Pennsylvania. Pennsylvania requires quarterly inspections of all onshore gas processing plants and compressor stations in the gathering and boosting sector.[144] Like Colorado, Pennsylvania requires that operators inspect for and repair methane leaks as well as VOC leaks. Pennsylvania requires operators to utilize either a FLIR camera or "other leak

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[135] Quarterly inspections are required at gathering sector compressor facilities with uncontrolled emissions between 12 and 50 tons of VOCs from equipment leaks and at well sites and tank batteries with uncontrolled emissions between 20 and 50 tons of VOCs from the largest condensate or oil storage tank onsite. CDPHE estimates that 55% of well sites and tank batteries will be subject to quarterly inspections (*see* CAPCD Cost-Benefit, Table 27).
[136] CAPCD Cost-Benefit, at 28, Table 34.
[137] *See id*. Cost effectiveness for compressor stations is calculated as net annual leak inspection and repair costs in Table 26 (adjusted from $3.5/Mcf to $4/Mcf of gas savings) divided by methane reductions in Table 32 (converted from short tons to metric tons and assuming methane is 86.1% of CH4/ethane); cost effectiveness for well sites is calculated as net annual leak inspection and repair costs in Table 30 (adjusted from $3.5/Mcf to $4/Mcf of gas savings) divided by methane reductions in Table 35 (converted from short tons to metric tons and assuming methane is 86.1% of CH4/ethane).
[138] *Id*. at 28. This reflects the cost effectiveness of conducting annual, quarterly and monthly inspections. The Division calculated the cost effectiveness of conducting a one-time inspection at the smallest well sites as $409/ton of VOC and $249/ton of methane/ethane. *Id*. at 29.
[139] *Id*. at 27.
[140] WY Permitting Guidance.
[141] Wyoming Department of Environmental Quality Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6, (UGRB permit by rule for existing sources), *available at* http://soswy.state.wy.us/Rules/RULES/9868.pdf; WY Permitting Guidance, at 16.
[142] *See* Ex. TA3, Jonah Energy LLC, presentation at the WCCA Spring Meeting, May 8, 2015, at 17 (reporting annual gas savings exceeding labor and material costs every year during the five years of the program, beginning in 2010); *see also* Ex. TA7, EDF, Comments to Mr. Steven A. Dietrich on proposed requirements for existing oil and gas production facilities/sources in the Upper Green River Basin, (July 11, 2014), at 5.
[143] Ohio General Permit. Operators may, however, reduce frequency if no more than 2% of the components are found leaking after six consecutive inspections, but the frequency reverts back to the original monitoring frequency upon detection of a higher leak threshold.
[144] Pennsylvania General permit, Section G.

detection monitoring devices approved by the Department."[145]

- Utah. Utah requires quarterly inspections at well sites and storage tank batteries using an IR camera, Method 21, or tunable laser absorption spectroscopy.[146]

Furthermore, Pennsylvania, Wyoming, and Colorado do not allow operators to adjust the frequency of inspection based about the reported survey results, as EPA has proposed.

4. EPA Should Strengthen Frequency Requirements in the Final Rule.

In summary, EPA should strengthen frequency requirements in two important respects:

- Strengthen baseline monitoring frequency. As described above, there is substantial evidence supporting the cost-effectiveness of quarterly monitoring programs, and EPA should strengthen the frequency of inspection by requiring quarterly monitoring for affected facilities. At the same time, we recognize an approach based on a single model facility necessarily fails to capture substantial variation among facilities. Indeed, EPA's own model well analysis reflects this substantial variation among basins, with average wells per pad ranging from one to 13.[147] Accordingly, if EPA does not finalize a quarterly requirement, we recommend a tiered approach to monitoring frequency similar to Colorado's. Such an approach would optimize monitoring requirements based on facility size and complexity.

- Remove step-down provisions. In addition, EPA's proposed step-down provisions, which allow frequency adjustments based on the percentage of leaking components, are arbitrary, unrelated to emissions performance, and should be removed from the final standards.

D. EPA's Definition of Modifications is Reasonable; Falls Squarely within the Agency's Clean Air Act Authority; and Should Encompass Other Activities with Similar Attributes.

In addition to new source requirements, EPA has proposed to define certain activities at well sites and compressor stations as modifications, requiring sources that undertake these changes to perform LDAR. In particular, EPA has concluded that (1) drilling a new well; (2) re-fracturing a well; and (3) adding or making a physical change to a compressor at a compressor station are modifications. EPA's determination is reasonable, fits squarely within the statutory definition of 'modification' under section 111(a)(4), and likewise comports with past EPA actions defining modifications in this industry and others. Below, we urge EPA to include other activities that fall within the statutory definition of modification, which are significant sources of fugitive emissions and are well within EPA's authority to regulate under this NSPS.

1. EPA has Broad Authority to Define Modifications.

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[145] *Id.*, Section H.
[146] Utah General Permit, at II.B.10.a.1.
[147] TSD, at 52- 54.

Section 111 of the Act defines a "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source[.]"42 U.S.C. § 7411(a); *see also Evtl. Defense v. Duke Energy Corp.*, 549 U.S. 561 (2007). The regulatory definition in EPA's General Provisions implementing Section 111 provides that a "modification" is "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies …." 40 C.F.R. § 60.14(a).

Consistent with the plain terms of the statute and implementing regulations, the General Provisions also recognize that EPA is not bound to these exceptions and instead has ample authority to define "modification" in particular rules consistent with the statute. Such definitions "shall supersede any conflicting provisions of this section," i.e., any of the listed exceptions. *Id***.** § 60.14(f). Indeed, in the 1974 rulemaking establishing the separate regulatory section for modifications in the NSPS program, EPA noted that the legislative history supporting section 111 "allows considerable latitude in interpreting phrases in the definition of modification such as 'stationary source' and 'increases the amount of any air pollutant emitted.'" 39 Fed. Reg. at 36,946.

In past NSPS rulemakings, EPA has exercised its robust statutory authority to adopt definitions for particular source categories. These include past actions to address emissions from the oil and gas sector, where EPA, citing the statutory definition, determined that re-fracture of a hydraulically fractured natural gas well constituted a modification requiring application of reduced emission completion technology. 77 Fed. Reg. 49,490, 49,511. The agency explained that in order to fracture an existing well during recompletion, re-perforation of the well causes physical change to the wellbore and casing. The process therefore results in a physical change to the wellhead, the affected facility subject to NSPS, as well as an increase in emissions. Proposed Rule, 76 Fed. Reg. 52,738, 52,745 (Aug. 23, 2011). EPA has taken a similar approach to defining modification for flares at petroleum refineries, *see* 40 CFR § 60.100a(c),[148] and for municipal solid waste landfills, *see* 40 CFR § 60.751.[149]

Courts have upheld EPA's broad approach to the Section 111 modification provisions. *See Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 905, 909 (7th Cir. 1990) (noting the potentially broad reach of the modification requirements and concluding "[n]or can we find any support in the relevant case law for the narrow constructions of 'modification' and 'physical change [put forward by petitioners]'"); *cf. Envtl. Defense*, 549 U.S. at 565 (overturning decision requiring EPA to define "modification" consistently for purposes of the NSPS and Prevention of Significant Deterioration ("PSD") program and noting that a rigid application NSPS modification definition in the PSD context "was inconsistent with [the PSD provisions] and effectively invalidated them").

2. EPA's Authority Clearly Encompasses the Activities the Agency has Defined as Modifications.

[148] "[A] modification to a flare occurs if: (1) Any new piping from a refinery process unit or fuel gas system is physically connected to the flare (e.g., for direct emergency relief or some form of continuous or intermittent venting); or (2) a flare is physically altered to increase flow capacity of the flare."

[149] ("Modification means an increase in the permitted volume design capacity of the landfill by either horizontal or vertical expansion based on its permitted design capacity as of May 30, 1991.").

EPA has concluded that (1) drilling a new well; (2) re-fracturing a well; and (3) adding or making a physical change to a compressor at a compressor station are modifications. For well sites, the agency provides the following rationale for its determination:

> When a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well.

80 Fed. Reg. at 56,614. Similarly, for compressor stations, the agency notes:

> Since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components.

Id. These activities fit within the statutory definition of modification: they are clearly physical or operational changes, and evidence demonstrates that such increases in production, system complexity, and compression are associated with increased emissions. In particular:

- System Complexity. In the production sector, "the number and type of equipment that could be potential leak sources generally scales with the number of wells."[150]

- Increases in Production. In the production sector, gas production rates have been found to have a weak positive correlation with methane emissions.[151] In the gathering and processing sector, absolute methane emissions are generally higher at facilities with larger throughput (although emissions can represent a greater percentage of total throughput at smaller facilities).[152] Also in this sector, throughput differences explain a portion of methane emissions from gathering facilities.[153] Moreover, Colorado tiers LDAR requirements based on actual uncontrolled tank emissions, which are tied to increases in throughput and, in a recent rulemaking, EPA itself has recognized that routing a new well to a storage tank can increase emissions from the storage vessel. Proposed Rule, 78 Fed. Reg. 22,126, 22,131, 22,139 (Apr. 12, 2013).

- Increases in Pressure. In the gathering and processing sector, "[t]he variation in methane emissions appears driven by differences between inlet and outlet pressure, as well as

[150] Allen (2013), Supporting Information, at S-32, *available at* http://www.pnas.org/content/suppl/2013/09/11/1304880110.DCSupplemental/sapp.pdf.
[151] Brantley (2015), at 14513.
[152] Mitchell (2015), at 3224.
[153] *Id*.

venting and leaking equipment."[154] Also in this sector, "[t]he magnitude of some fugitive leaks scale with pressure."[155]

3. EPA Should Identify Additional Activities as Modifications.

Other activities have many of the same attributes as the actions EPA has proposed to identify as modifications. In particular, EPA should clarify that well workovers with hydraulic fracturing are the same thing as a completion with hydraulic fracturing, and thus a modification. Further, EPA should designate (1) well workovers with acidizing or re-perforation; (2) the installation of an additional compressor engine at a well site; and (3) the addition of other equipment, including dehydrators, that are a potential source of fugitives as activities constituting modifications for purposes of inclusion in LDAR requirements.

Well workovers that include the use of hydraulic fracturing constitute both physical and operational changes, satisfying the section 111(a)(4)'s definition of modification. These physical and operational changes at the well site are invasive procedures requiring a significant capital expenditure, and are conducted only when the existing well's production is faltering. EPA,[156] the Wyoming Department of Environmental Quality, [157] and the American Petroleum Institute[158] have presented evidence identifying a number of non-routine workover procedures. Moreover, hydraulic fracturing is proven to cause an increase in emissions from the wellsite.[159] And well workovers with and without hydraulic fracturing have been shown to cause comparable emissions: in a study of direct measurements of workover emissions, Allen. et al. found that

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[154] Mitchell (2015), at 3219.
[155] *Id*. at 3225.
[156] *See* EPA, TSD for the Proposed NSPS Subpart OOOO, 4-27 (July 2011) (discussing EPA's understanding of the work performed in order to recomplete the well: "… it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS."). *See also* EPA's proposed definition of a workover: "For the purposes of this subpart, a workover that occurs after August 23, 2011 at each affected facility for which construction, reconstruction, or modification commenced on or before August 23, 2011 is considered a modification for which a notification must be submitted under § 60.7(a)(4)." § 60.5420, 76 Fed. Reg. 52807 (Aug. 23, 2011).
[157] WY Permitting Guidance ("Workover – Any downhole operation in an existing oil or gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or gas well. Workover includes but is not limited to: acidizing, reperforating, fracture treating, sand/paraffin removal, casing repair, squeeze cementing or setting bridge plugs to isolate water productive zones from oil or gas productive zones or any combination thereof. *Workover does not mean the routine maintenance, repair or replacement of downhole equipment such as rods, pumps, tubing, packers or other mechanical devices*." (emphasis added)).
[158] "Well workover means the work conducted on wells with a rig or coiled tubing unit after the initial completion is over. Such process(es) may include performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production or return the well to its normal production rate. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to refracture and prop-open new fractures in existing low permeability reservoirs or re-complete an existing well to a new production zone/horizon. **A well workover does not include routine maintenance activities that are performed on the well with the tree installed (See 30 CFR Part 250.601 Definitions for further details). Such routine activities may include maintenance, repair, or replacement of equipment such as rods, pumps, tubing, packers, or other mechanical devices**." [**emphasis added**] November 30, 2011 (Docket ID No. EPA-HQ-OAR-2010-0505-4266)
[159] EPA, TSD for the Proposed NSPS Subpart OOOO, 4-27 ("much of the emissions data on which [EPA's NSPS] analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations.").

potential emissions from flowback following a workover without hydraulic fracturing "are of the same order of magnitude as the EPA estimated value of 4.2 million scf for workovers with hydraulic fracturing."[160]

Like workovers with hydraulic fracturing, well workovers with acidizing and with re-perforating are treatments used to return a low-functioning well to productivity. Well acidizing, a form of fracturing using acid, typically involves pumping acid into the wellbore to remove formation damage, improving permeability and flow—the acid dissolves sediments that inhibit permeability to increase the effective well radius. Re-perforating, including adding shallower or deeper perforations in a well's cement liner or casing, is the process of clearing the wellbore and perforation holes that have been clogged by sediment.

Both types of workovers clearly cause a physical change to the wellbore and casing, and therefore a physical change to the wellhead, within section 111(a)(4)'s definition of 'modification.' These activities also result in increased fugitive emissions throughout the affected facility from production rate increases.[161]

The installation of an additional compressor engine at a well site should also be considered a modification. EPA has specifically identified the addition of a compressor as a modification of a compressor station. 80 Fed. Reg. at 56,614. It should qualify as a modification in other segments, including the production segment. As EPA noted, "expansion of compression capacity . . . through addition of a compressor . . . would result in an increase in emissions." *Id.* The addition of a compressor at a well site is a physical change that causes an increase in pressure as well as an increase in system complexity, both of which increase fugitive emissions. Compressors, as sources of vibration and heat,[162] are associated with significant fugitives – as shown in Table 1 *supra*, 54% of all leaks from aboveground sources in the oil and gas industry originate from compressors.[163] An additional compressor brings with it an increase in leaks from the gas supply lines that feed it and an increase in pressure throughout the system, which causes amplify emissions from associated equipment. Similarly, the addition of dehydration equipment at either a well site or compressor station should be considered a modification of the facility.

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[160] Allen (2013 or 2015?), at 228.("The data set reported here is very small, in part because the Study team was visiting production regions with high drilling activity and consequently relatively young wells not requiring workovers. Nevertheless, the emissions per event can be compared to average emissions for workover events in the national greenhouse gas emission inventory of 4.2 million scf/event for events involving hydraulic fracturing and 2570 scf/event for events without hydraulic fracturing (U.S. EPA, 2013). The average swabbing event emissions (2800 scf/event) are comparable to the workover estimates for workovers without hydraulic fracturing (2570 scf/event). The total gas generated during the recompletion workover (event 4) was approximately 1,000,000 scf of total gas. This well workover did not involve hydraulic fracturing, however, the potential emissions from the flowback are of the same order of magnitude as the EPA estimated value of 4.2 million scf for workovers with hydraulic fracturing. Because approximately 99% of the total gas flow was flared, the estimated emissions for the recompletion are only about 2% of the potential emissions.")

[161] *See* Brantley (2015).

[162] *See* Clearstone Engineering, *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*, 2006 at iii, *available at* http://www.epa.gov/gasstar/documents/clearstone_II_03_2006.pdf.

[163] This figure only includes fugitive emissions from static components on compressors. It does not include emissions from wet seal degassing units on centrifugal compressors, or rod-packing on reciprocating compressors.

E. Additional LDAR Issues On Which EPA Requests Comment.

EPA requests comments on a number of other items related to LDAR. We address these below.

EPA proposes to require operators conduct an initial inspection within 30 days of start-up of a new well site or compressor station, or within 30 days of modification of an existing well site or compressor station. 80 Fed. Reg. at 56,612. We agree that 30 days is the appropriate amount of time to require the first inspection. This is the timeframe Colorado allows for operators of new well sites, as well as large existing well sites and large new and existing compressor stations. 5 Colo. Code Regs. § 1001-9 XVII.F.4.a.

EPA also requests comment as to whether or not Method 21 should be allowed as an alternative to OGI to conduct the initial inspections and if so, what the appropriate threshold should be to define a leak. 80 Fed. Reg. at 56,612. We believe OGI is generally superior to Method 21, due to its efficacy in scanning entire facilities for leaks and directly locating leaks.[164] If EPA decides to allow Method 21 for initial inspections, 500 ppm would be the appropriate threshold to define a leak, consistent with the leak threshold for gas processing plants from NSPS Subpart OOOO. Given the advantages of OGI, its low cost, and the availability of service providers to perform OGI (relieving small operators of the need to purchase equipment, for example), EPA should also consider approaches that would encourage OGI, such are requiring that one inspection per year be carried out with OGI. EPA also requests comment as to the appropriate approach—OGI or Method 21—operators should use to re-survey repaired components, and if Method 21 is allowed, whether or not 500 ppm is an appropriate threshold to require to verify a repair. 80 Fed. Reg. at 56,612. We note that most state LDAR programs allow operators the flexibility to use either of these approaches, with the same frequency, as well as other approved instrument monitoring, and we support this flexible approach. Consistent with our comments above, if operators use Method 21, 500 ppm is the appropriate threshold for determining whether a leak has been repaired.. ."This is the threshold required by the Colorado rules for components at new and existing well sites and at new compressor stations. 5 Colo. Code Regs. § 1001-9 XVII.F.6. It is also the threshold Utah requires for well sites authorized under its General Permit.[165]

EPA also requests comment as to its proposed 15-day repair timeframe. We support this timeframe as reasonable and in line with leading state requirements. Specifically, while the Colorado rule requires an initial attempt within five days, if a delay is warranted, operators must justify that delay and, when that justified reason ceases, operators then have 15 to make the repair. Pennsylvania allows operators of compressor stations and well sites 15 days to make repairs. Utah similarly requires the first attempt to repair a leak within five days of detection, but no later than 15 days after detection.[166] Accordingly, EPA's 15-day repair timeframe is reasonable.

Finally, EPA requests comment on whether fugitive emissions monitoring should be limited to "gross emitters." 80 Fed. Reg. 56,637. As we have commented in section B above, the occurrence of super-emitters / gross-emitters is not predictable. Such an approach is not

[164] TES LDAR 2015, at 8.
[165] Utah General Permit, at II.B.10.a.1.
[166] *Id.*, at II.B.10.a.b.

workable. Comprehensive monitoring is required to ensure that when improper conditions occur, repairs are rapidly made to ensure that unnecessary and harmful emissions do not continue.

F. EPA must remove exemption for LDAR for equipment "not in VOC service" at gas processing plants, and remove skip inspection provisions for these facilities

EPA's proposal also extends methane standards to equipment leaks at onshore natural gas processing plants. Id. at 56,669 (proposed 40 C.F.R. § 60.5400a). However, EPA uses almost precisely the same language for the methane regulations as it did in the 2012 VOC rules. *Compare* 40 C.F.R. § 60.5400 *with* Proposed 40 C.F.R. § 60.5400a. The unfortunate, and presumably unintended, effect of this is that EPA proposes to exempt equipment "not in VOC service" – less than 10.0 percent VOC by weight – or in wet gas service. 80 Fed. Reg. at 56,669 (proposed 40 C.F.R. § 60.5400a(f)). Of course, this "low VOC gas" is still predominantly methane – which, despite its established role as a precursor of ground-level ozone pollution, is not treated as VOC by EPA. Therefore, this provision will exempt potentially significant sources of methane.

Exempting emissions of methane-rich natural gas from a methane regulation on the basis of their low VOC content is unreasonable. Indeed, EPA's proposal extends coverage of the methane regulations to sources in the transmission and storage segment that were not regulated by the 2012 VOC rule because of low VOC content. *See, e.g.*, 80 Fed. Reg. at 56,664 (proposed 40 C.F.R. § 60.5365a(d)).EPA must remove proposed 40 C.F.R. § 60.5400a(f), the provision that creates the exemption, and remove the reference to §§ 60.5400a(f) in §§ 60.5400a(d). Finally, EPA must amend the definition of "equipment" in proposed 40 C.F.R. § 60.5430 to make clear equipment at processing plants is not exempted from methane leak detection and repair requirements based on VOC content.

Consistent with our comments above, EPA must also remove the reduced inspection frequency provisions for gas processing plants in the proposed standards (§§ 60.5400a(b)). Gas processing plants, like other oil and gas facilities, are subject to the super-emitter phenomena, and leak frequency is a very poor metric for facility emissions. Finally, the poor incentives that these provisions create are a concern at gas processing plants.

G. EPA Should Create a Pathway that Incentivizes Innovations in Monitoring Technology

Equipment leaks are a significant source of methane emissions from facilities across the oil and natural gas sector. We discussed earlier in this section several recent studies suggesting that these sources could be even larger than previously understood, due both to systematically significant leaks and large super-emitters.[167]

As noted above, several states and leading companies have been deploying instrument-based LDAR, using technologies like OGI cameras to detect leaks. These technologies are effective, though leaks will continue until facilities are surveyed.

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[167] Allen (2013).

At the same time, as we describe above, advanced LDAR technologies are being swiftly developed. Accordingly, we encourage EPA to design standards in a way that rewards innovation by providing an equivalency pathway. The key test should be whether such alternative technologies will achieve equal or greater emissions reductions. Other considerations are pertinent to making this assessment, including:

- Frequency. As described above, technologies that enable more frequent (and indeed, continuous) monitoring can minimize emissions by ensuring leaks do not persist until the next scheduled survey and catching intermittent leaks that would be missed entirely.
- Accuracy. Minimum detection limits should be sufficiently sensitive to permit accurate detection of leaks comparable to those detected by existing technologies.
- Robustness. Technologies should be capable of reliably operating in adverse meteorological conditions.

When determining equivalency, EPA should assess these technologies holistically. For instance, a system that is capable of continuous detection may identify a large number of leaks simultaneously across facilities, resulting in the need to prioritize repairs and possibly modest delays at certain sites. However, such a system could still outperform semi-annual surveys given the far earlier detection. Evaluation of these technologies should recognize their potentially substantial real-world benefits.

It is likewise important to ensure that any determination of equivalency is administratively reasonable, clear, and timely. This process must be fully transparent: the resulting assessment and determination should be publicly available and should be designed to foster strong public confidence in the rigor of EPA's determination. Any party should be permitted to make an equivalency request. EPA's standard should include a clear deadline for acting on a submitted request—e.g., between three and six months. It should also include clear, fact-based criteria for determining whether an alternative system or technology is securing equal or greater emission reductions.

The equivalency determination needs to be broad in another important dimension: creating flexibility for different technical sensing strategies. Methane and VOCs are frequently co-emitted, with methane being prevalent at production sites. 80 Fed. Reg. at 56,635. Further down the supply chain, methane emissions predominate even more strongly over VOCs. *Id*. at 56,640. Because of the commingling of pollutants, methane emissions are in many circumstances (particular upstream of processing plants) a good indicator for VOC emissions, and a response to fix a leak will address both pollutant types in one measure. Current trends indicate that emerging low-cost technology with the highest readiness level detects methane only. To keep the focus on environmental outcomes and create space for such advancing technologies, EPA's equivalency determination should look to the emissions result rather than the sensing mechanism itself. In other words, if a detection system achieves equivalent reductions in methane and VOCs as the BSER, it does not matter that the system only measures methane emissions.

Finally, the standards should be designed to incent competition in the leak detection market by eliminating duplicative requirements as technologies are proven to be equivalent. For example, periodic OGI monitoring should not be required for operators that have adopted an approved alternative work practice such as continuous detection systems. EPA should also examine the rest of the standard and eliminate redundant aspects that would no longer add value.

EPA has included numerous such alternative pathways under existing section 111 programs:

- The general provisions related to monitoring expressly provide "[a]fter receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part. 40 C.F.R. § 60.13(i).

- Likewise, the NSPS for petroleum refineries includes work practice standards for flares and, along with those standards provides "[e]ach owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section." *Id.* § 60.103a(i). These regulations also allow equipment manufacturers to apply for equivalency determinations.

- Subpart VVa includes similar procedures applicable to equipment leaks at chemical manufacturing facilities. *Id.* § 60.484.

Given these past examples and the rapid development of LDAR technologies that can both enhance environmental benefits and dramatically lower costs, we respectfully urge EPA to include in its final section 111 standards a compliance pathway that recognizes and incentivizes this technological innovation.

IV. Oil Well Completions

EPA proposes to require reduced emission completions at hydraulically fractured oil wells. Oil well completions are a significant source of emissions, likely responsible for over 100,000 tons of methane emissions annually. Moreover, the same technologies available to reduce emissions at gas wells can mitigate oil well completions emissions. Capture and beneficial use of natural gas that would otherwise be wasted can significantly offset costs associated with deploying these technologies. Accordingly, we strongly support EPA's proposal to extend reduced emissions completion (REC) requirements to hydraulically fractured oil wells.

A. EPA Should Ensure Provisions Requiring Capture and Beneficial Use of Completion Emissions are Rigorously Applied.

As in the 2012 VOC rule with respect to gas wells, EPA includes in the Proposed Rule an exemption for certain classes of oil wells from the REC requirements. Specifically, EPA proposes the following requirements:

> During the separation flowback stage, . . . [r]oute the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into

> the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section.[168]

The requirements in paragraph (a)(3) provide that in such a "technically infeasible" scenario, the operator "must capture and direct recovered gas to a completion combustion device," with certain additional exceptions.[169] Toward better defining the standard of technical feasibility, EPA has solicited comment "on criteria that could help clarify availability of gathering lines," as well as "any other factors that could be specified in the NSPS for requiring recovery of natural gas from well completions."[170]

As stated, we strongly support the Proposed Rule's REC requirement at oil wells, which were not addressed in the 2012 VOC rule. As currently stated in the Proposed Rule, however, the "technically infeasible" exemption could detract significantly from the overall value of this standard if not limited narrowly. The swiftly increasing production of oil (along with associated natural gas) in the Bakken shale formation demonstrates the need for a strong rule. Production in the Bakken hit an all-time high in July 2015, and the number of producing wells reached an all-time high in August 2015.[171] Tight oil formations, like the Bakken, produce very high initial rates of oil and associated gas, which then decline rapidly. For instance, an "example well" may produce 340 million cubic feet per day of associated natural gas in the first month of production.[172] Given this quickly expanding production and resulting potential for high initial emissions, it is vital that the Proposed Rule's REC requirements apply rigorously.
To this end, Commenters provide data on the factors for which EPA has solicited input and urge EPA to ensure maximum gas capture, to improve compliance and enforcement and for other reasons described below.

1. Operators Have Many Options To Use Captured Gas.

In the proposed rule, EPA has recognized that capture and beneficial use of natural gas is far preferable to alternatives that involve flaring. Consistent with that understanding, Commenters urge EPA to tightly limit the provision that operators of hydraulically fractured oil wells may flare associated natural gas where routing to a gathering line or collection system is "technically infeasible." As currently crafted, this provision is vague and runs counter to the improvements EPA seeks to establish within the oil and gas industry. Furthermore, it is very rarely necessary. EPA has identified *four* separate options for utilizing gas captured through RECs: operators may

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[168] 80 Fed. Reg. at 56,665 (proposed 40 C.F.R. § 60.5375a(a)(1)(ii)).
[169] *Id.* (proposed 40 C.F.R. § 60.5375a(a)(3)).
[170] *Id.* at 56,634.
[171] *See* N.D. Industrial Comm., Dep't of Mineral Res., *Director's Cut* 1 (Nov. 2015), *available at* https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2015-11-13.pdf.
172[172] *See* Memo from Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, U.S. Dep't of Energy, to Member of the Public, Re: QER Public Stakeholder Meeting: Infrastructure Constraints in the Bakken 3 (Aug. 8, 2014) [hereafter DOE, Bakken Memo], *available at* http://energy.gov/sites/prod/files/2014/08/f18/FINAL-%20BAKKEN%20BRIEFING%20MEMO_8%208.14.pdf.

(1) "[r]oute the recovered gas from the separator into a gas flow line or collection system; (2) "re-inject the recovered gas into the well or another well;" (3) "use the recovered gas as an on-site fuel source;" or (4) "use the recovered gas for another useful purpose that a purchased fuel or raw material would serve."[173]

Even if an operator is unable to route the natural gas to a gathering line, or if no such infrastructure exists near the oil well site, there are three other options available for operators to use gas captured during the REC, including one that is broadly defined to cover any "useful purpose that a purchased fuel or raw material would serve."[174] Given the broad scope of this language and the available technologies we describe below, EPA must ensure that operators rigorously evaluate these alternatives as part of compliance with REC requirements. As the U.S. Department of Energy discussed in a 2014 analysis of infrastructure in the Bakken, these uses for gas other than routing to a gathering line or flaring are becoming even more feasible as industry invests "in technology to use the natural gas produced from newly drilled wells until output stabilizes and gathering lines can be completed. Some technologies include converting natural gas to liquid fuels, mobile [natural gas liquids (NGL)] extraction, producing fertilizer from wellhead natural gas, or developing onsite electrical generation."[175] Recent examples include a process in which an operator could "capture gas at the wellhead, strip out valuable NGLs, compress it into [compressed natural gas (CNG)]," which could then be used as fuel source, and "small-scale gas-to-liquids" units, which could be brought to wellheads where no gathering infrastructure exists.[176] These technologies demonstrate that even if a well is unable to connect to a gas gathering system, there are many feasible options in addition to flaring.

Moreover, the costs of these technologies are reasonable. A recent Carbon Limits study commissioned by the Clean Air Task Force examines the options for capture, transport, and use of associated natural gas as alternatives to flaring.[177] The study finds three options in particular are proven and in-use in tight oil formations: NGL recovery, CNG trucking, and gas-to-power generation. Carbon Limits describes case studies of existing installations of these technologies, where they are making money for companies that use them.[178] Even where there is a net cost involved, that cost is small considering the large amount of pollution that is prevented when these technologies are used. The Carbon Limits study modeled the economic costs and environmental benefits of these technologies at typical tight oil wells.[179] The results of this cost analysis are summarized in the Table 7. At nearly all wells, one or a combination of several of

[173] 80 Fed. Reg. at 56,665 (proposed 40 C.F.R. § 60.5375a(a)(1)(ii)). We note that this language may not fully reflect EPA's intent that all of these options must be technically infeasible before an owner or operator may send the gas to a completion combustion device. EPA should clarify this language to make it consistent with its intent as stated in the preamble. *See* 80 Fed. Reg. at 56,631 ("If, during the separation flowback stage, it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted.").
[174] *Id.* at 56,665 (proposed 40 C.F.R. § 60.5375a(a)(1)(ii)).
[175] *See* DOE, Bakken Memo, *supra* note 172, at 15.
[176] *Id.*
[177] *See* Carbon Limits AS, *Improving Utilization of Associated Gas in U.S. Tight Oil Fields* (rev. Oct. 2015), *available at* http://www.catf.us/resources/publications/files/Flaring_Report.pdf.
[178] *Id.* at 55-56.
[179] *See id.*

these technologies can be utilized. NGL recovery and gas to power (for local loads) can be suited for remote wells, while CNG trucking is economically feasible at wells that are relatively close to a processing plant or other point where gas can be put into the pipeline system (20-25 miles or less).

Table 7: Cost Analysis of Alternatives to Flaring Associated Gas in Tight Oil Formations[180]

	Gas Composition	Pad Size	Flare Reduction	CO_2eq Reduction (including compressor emissions)	Abatement Cost ($/ton CO_2)
CNG Trucking	Lean	Single Well	91% to 97%	65% to 85%	-$26 to $0
		Multi Well	95% to 97%	70% to 85%	-$53 to -$40
	Rich	Single Well	93% to 98%	65% to 85%	-$126 to -$107
		Multi Well	96% to 98%	70% to 85%	-$159 to -$151
NGL Recovery (C5+)	Rich	Single Well	4%	5%	*$250*
		Multi Well	4% to 5%	5% to 6%	-$21 to $0
NGL Recovery (C3+)		Single Well	14% to 18%	15% to 19%	-$23 to $0
		Multi Well	18% to 21%	19% to 22%	-$89 to $0
Reciprocating Engine	Lean	Single Well	18%	33%	-$165
		Multi Well	19%	36%	-$194
Gas Turbine		Single Well	21%	31%	-$33
		Multi Well	22%	33%	-$54

Current state initiatives and regulations further demonstrate that operators are increasingly capable of using capture technologies to reduce flaring. As EPA stated in the Technical Support Document to the 2012 NSPS rule and repeated in the Technical Support Document to the Proposed Rule, "[t]he State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area . . . ."[181] For operators in the Bakken formation, North Dakota set a series of milestones for reducing flaring of associated gas: 26 percent by October 2014; 23 percent by January 2015; 15 percent by January 2016 and 10 percent by October 2020.[182] To achieve these milestones, the state requires operators to submit a "gas capture plan" in its application to drill and will impose restrictions on a well's production if an operator does not meet the applicable milestone.[183]

[180] Source: Carbon Limits AS, *supra* note 177.

[181] See EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document 4-14 (2011); Technical Support Document at 25.

[182] *See* N.D. Industrial Comm., Order No. 24665 at 4 (July 1, 2014) [hereafter NDIC Order], *available at* https://www.dmr.nd.gov/oilgas/or24665.pdf. While operators have achieved (and surpassed) the January 2015 milestone, the state has since amended the January 2016 15-percent milestone to allow the industry until November 2016 to comply. *See* Ernest Scheyder, *North Dakota postpones deadline for natural gas flaring rules*, Reuters, Sep. 24, 2015, *available at* http://www.reuters.com/article/2015/09/24/us-north-dakota-flaring-idUSKCN0RO2KX20150924#yD33dx5QYqpeGfEi.99.

[183] *See* NDIC Order, *supra* note 182, at 1, 5; Lauren Donovan, *Five companies face restrictions after flaring too much gas*, Bismarck Tribune, April 2, 2015 ("Starting this month, the companies were ordered to choke down production to 100 barrels per day on certain wells or face potential daily penalties.").

Where states have pushed for these needed reductions and changes, operators have demonstrated that they largely have the capability to reduce flaring and use this captured gas for beneficial purposes, even as production has increased. For example, North Dakota operators have greatly increased their capacity to collect, transport, and process natural gas over the last several years. As the Department of Energy recently summarized on North Dakota's progress, "nearly $6 billion has been invested by the natural gas capture industry since 2006. Since that time, the industry has built more than 9,555 miles of gas gathering pipeline, 1.259 bcf/d of gas processing, and increased export capacity for residue gas and NGLs."[184] Processing capacity jumped five-fold between 2006 and 2013; by the end of 2015, processing capacity in North Dakota will reach 1.6 billion cubic feet per day, "an amount on par with total gross withdrawals."[185]
In fact, the most recent production and processing data from the state suggest that the processing capacity already matches production: according to the North Dakota Pipeline Authority, "North Dakota currently has twenty-four natural gas processing/conditioning plants operating, with the capability to process roughly 1.6 BCFD," or 48 billion cubic feet per month, while the state's natural gas production was 48.11 billion cubic feet in September 2015.[186]

The actions of individual operators also demonstrate the achievability (and profitability) of gas capture technologies and reductions in flaring. Individual North Dakota companies have increased their collection and processing capacity to reduce flaring and enhance revenue at a rate significantly above the statewide milestone. For example, Whiting Petroleum captured more than 85 percent of its associated natural gas in the first quarter of 2015, well above the current state milestone of 77 percent.[187] The company, which operates about 12 percent of the state's nearly 13,000 active oil and gas wells, intends to improve on this capture rate through the expansion of its processing capacity.[188] A review of Whiting's facility locations demonstrates that the company has apparently grouped its wells and processing plants near each other, thereby increasing the feasibility of capturing and selling associated natural gas.[189]

Accordingly, operators have a variety of options available to them for using gas captured through RECs. If pipeline infrastructure exists on-site or nearby, they can direct it there for eventual sale.

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[184] *See* DOE, Bakken Memo, *supra* note 172, at 14.
[185] *See* EIA, *Today in Energy* (Nov. 13, 2015); *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=23752..
[186] *See* N.D. Pipeline Auth., Annual Report: July 1, 2014 – June 30, 2105 at 12 (2015), *available at* http://www.nd.gov/ndic/pipe/publica/annual-report15.pdf; N.D. Pipeline Auth., Gas Plants, http://northdakotapipelines.com/gas-plants/ (last visited Nov. 29, 2015); N.D. Dep't of Mineral Res., North Dakota Drilling and Production Statistics: Historical monthly gas production and sales statistics, https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp (accessed Nov. 24, 2015).
[187] *See* Daniel J. Graeber, *North Dakota gas capturing up for Whiting*, UPI, April 30, 2015, *available at* http://www.upi.com/Business_News/Energy-Industry/2015/04/30/North-Dakota-gas-capturing-up-for-Whiting/2421430394613/.
[188] *Id.*; Well data obtained from Dep't of Mineral Res., N.D. Industrial Comm., NDIC Oil and Gas ArcIMS Viewer, https://www.dmr.nd.gov/OaGIMS/viewer.htm (accessed Nov. 24, 2015).
[189] *See* Ex OW-1. Well locations obtained from Dep't of Mineral Res., N.D. Industrial Comm., NDIC Oil and Gas ArcIMS Viewer, https://www.dmr.nd.gov/OaGIMS/viewer.htm (accessed Nov. 24, 2015); coordinates of compressor stations and gas plants obtained from N.D. Dep't of Health, Air Quality Permit Portal, http://www.ndhealth.gov/AQ/ActivePermits.aspx (accessed Nov. 24, 2015).

Otherwise, they can put it to any number of other uses, including (but not limited to) those described above. Flaring is, in the vast majority of cases, an unnecessary and wasteful alternative to more productive options. EPA should therefore either remove the exemption for flaring in the event of "technical infeasibility" or strictly limit the exemption according to the principles described in the following subsection.

2. EPA EPA Must Add Provisions Requiring Operators to Demonstrate the "Technical Infeasibility" of Each of the Options and Consideration of Such Claims on a Case-by-Case Basis.

A narrowly defined "technical infeasibility" exemption from the REC requirement should include in the final rule provisions requiring operators to demonstrate adequately, through the submission of documentation and supporting information, that each one of the four options is technically infeasible. EPA and state agencies could then consider such claims on a case-by-case basis.

Given that EPA has solicited comments on certain aspects of the technical infeasibility exemption, including those helping to clarify the availability of gathering lines and the types of oil wells not capable of performing a REC, EPA should add provisions to the final rule that require notification, submission of supporting information, and consideration by EPA and state agencies of claims of technical infeasibility. Such case-by-case considerations could serve to provide the agency and the public with needed information, help to ensure that operators are fully considering environmentally preferable alternative options, and give additional information to EPA on what factors constitute true technical infeasibility.

A useful model for such a new provision is North Dakota's gas capture report. Prior to completing a well, operators in North Dakota must submit a report detailing and supporting certain factors, including:

1. An affidavit signed by a company representative indicating that the operator met with gas gathering companies;
2. A detailed gas gathering pipeline system map, including the proposed route and tie-in point to connect the well to an existing gas line;
3. Information on the existing line, to which operator proposes to connect including current daily capacity, throughput, and plans for expansion;
4. Anticipated date of first production, with oil and gas rates and duration (for all wells being completed, if on a multi-well pad);
5. Amount of gas the operator is currently flaring across the state; and
6. Alternatives to flaring available to and/or planned by the operator.[190]

In addition to these factors, the operator could provide the information demonstrating what factors specifically make routing, reinjection, use, or other alternatives to flaring technically

[190] *See* Memo from Todd L. Holweger, Dep't of Mineral Res., N.D. Industrial Comm., to Operators (May 8, 2014), *available at* https://www.dmr.nd.gov/oilgas/Gas%20Capture%20Plans%20Required%20on%20All%20APD's%20050814.pdf.

infeasible, such as exceptional geography, reasonably unforeseen circumstances, or factors beyond the control of the operator. This would help ensure that flaring only occurs when all other options have been thoroughly explored and rejected for justifiable reasons.

An appropriate location in the Proposed Rule for this submission and consideration of technical infeasibility claims would be under the existing notification requirements of 40 C.F.R. § 60.5420a(a)(2). The Proposed Rule currently states:

> If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.[191]

EPA could amend this provision to add new subparagraph (a)(2)(iii), with potential requirements as follows:

> If you intend to claim that it is "technically infeasible" to route, re-inject, or use recovered natural gas for a useful purpose, as specified in §60.5375a(a)(1)(ii), you must submit a notification to the Administrator no later than 30 days prior to the commencement of each well completion operation. The notification shall include the information required by paragraph (a)(2)(i), as well as: the reasons for the claim(s) of technical infeasibility; and detailed information and evidence supporting the claim(s), including, but not limited to, the name and location of the three closest gathering systems, capture and reuse technologies considered, the anticipated oil and gas production rates (for all wells being completed, if on a multi-well pad), and the amount of gas you are currently flaring at other operations. You must submit the notification in electronic format.

The primary differences between this notification and the existing notification provision, aside from the additional information required, are that the operator must submit the notification for claiming the exemption at least 30 days prior to completion and that the notification must be in electronic format to facilitate EPA's consideration and public accessibility. We urge EPA to make these requests, and EPA's ultimate determination, transparent and publicly available.

In connection with this new provision, EPA should amend the existing language of the exemption. While it is clear in the preamble to the Proposed Rule that the exemption applies where "it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose," the language of the Proposed Rule differs from the preamble and may confuse operators.[192] The Proposed Rule currently states "[i]f it is technically infeasible to route the recovered gas as required above," without also

[191] 80 Fed. Reg. at 56,688 (proposed 40 C.F.R. § 60.5420a(a)(2)).
[192] 80 Fed. Reg. at 56,631,

including "re-inject the gas or use the gas as fuel or for other useful purpose."[193] To make it clear that an operator must demonstrate all of the options to be technically infeasible, EPA should change the language of the exemption to read:

> If it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose, as required above, follow the requirements in paragraph (a)(3) of this section.

A case-by-case approach would place the burden of proof on those claiming the exemption and provide EPA with additional information on the availability of recovered gas capture and routing opportunities and alternatives, and increase public disclosure and transparency. Short of removing the exemption altogether, this approach (in conjunction with clarification that flaring is only permitted if four primary options are infeasible) would significantly improve the means by which EPA can reduce flaring, protect air quality, and prevent waste, and so meet its section 111 obligations.

3. EPA Should Not Base the "Technical Infeasibility" Analysis Solely on a Well Site's Proximity to Gathering Lines or Other Technology.

EPA has solicited "comment on criteria that could help clarify availability of gathering lines," given that this "is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells."[194] To the extent that this request indicates that the agency is considering whether a bright-line proximity rule should determine whether an operator at a well site should be permitted to flare rather than use captured gas for a beneficial purposes, Commenters believe that considering claims on a case-by-case basis is a much better option than a numeric cutoff based on distance. A bright-line proximity test would ignore that "technical feasibility" and availability of gathering systems are multi-factor considerations. In order to aid in EPA's decision making, we provide the following information and sources of data.

First, in response to EPA's solicitation of "comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery," Commenters urge EPA not to use distance as the sole criterion to determine whether an operator may flare captured gas rather than use it for a beneficial purpose. EPA recognizes that the availability of gathering lines is not a simple question of distance; rather, there are "several factors that can affect availability of a gathering line including, but not limited to, the capacity of an existing gathering line to accept additional throughput, the ability of owners and operators to obtain rights of way to cross properties, and the distance from the well to an existing gathering line."[195] A similar position is articulated in two recent analyses, by the North Dakota Petroleum Council Task Force and Three Affiliated Tribes Task Force (also in North Dakota), which found factors other than mere distance to have greater or equal influence on availability.[196]

[193] *Id.* at 56,631, 56,665 (proposed 40 C.F.R. § 60.5375a(a)(1)(ii)).
[194] 80 Fed. Reg. at 56,634.
[195] *Id.*
[196] *See* DOE, Bakken Memo, *supra* note 172, at 13.

Furthermore, the availability of the capture technologies discussed above, as well as current state regulations, militates against any proximity-only or proximity-driven determination. As EPA stated in the Technical Support Document to the 2012 rule and repeated in the Technical Support Document to the Proposed Rule, "[t]he State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area . . . ."[197] Where states have pushed industry for needed reductions and changes, such as with North Dakota's milestones and Wyoming's refusal to consider gathering line proximity as an excuse, operators have demonstrated their capability to adopt such measures and continue producing oil and gas profitably.

In light of these considerations, the case-by-case analysis identified above is a more appropriate mechanism for determining technical feasibility than a distance cutoff. Submissions by operators claiming the exemption should include the relevant data for determining the technical feasibility of their individual situations, which EPA or a state agency could consider as a basis for granting or rejecting a REC exemption. Distance alone does not provide the necessary information for such a determination.

To the extent that EPA considers gathering line proximity as one valid criterion going to technical infeasibility, there is a great deal of data available to the agency in setting this criterion. Three of the most detailed and promising sources—from two of the states with a great proportion of the oil wells subject to the rule—are the Texas Railroad Commission's digital map data on wells and pipelines and the North Dakota Industrial Commission's gathering line data and gas capture plans. The Texas Railroad Commission's mapping data is available online through a GIS viewer, to which members of the public may submit individual queries, and the raw data is available for purchase.[198] The North Dakota Industrial Commission possesses two sources of information: (1) a database of gathering lines across the state, as submitted by operators and including geographic information and fluid transported;[199] and (2) the gas capture plans submitted by well operators in advance of their completions and including the data described above.[200] This data could inform EPA decisions, though all of it is not publicly available.[201]

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[197] *See EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document 4-14 (2011);* ; EPA, *Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities: Background Technical Support Document* 24-25 (2015).

[198] *See* Tex. R.R. Comm., RR Public GIS Viewer, http://wwwgisp.rrc.state.tx.us/GISViewer2/ (last visited Nov. 30, 2015); Tex. R.R. Comm., Digital Map Data Statewide Prices, http://www.rrc.state.tx.us/about-us/resource-center/research/data-sets-available-for-purchase/digital-map-data/digital-map-data-statewide-prices/ (last visited Nov. 30, 2015).

[199] *See* N.D. Industrial Comm., Gathering Lines General Information, https://www.dmr.nd.gov/oilgas/mvc/ndgathering/ (last visited Nov. 30, 2015);

[200] *See* Memo from Todd L. Holweger, Dep't of Mineral Res., N.D. Industrial Comm., *supra* note 190.

[201] *See, e.g.,* N.D. Industrial Comm., Request Gathering Line Data ("The commission may not include information, if available, on any underground gathering pipeline that exists outside the bounds of the real property owned or leased by the requesting party."), https://www.dmr.nd.gov/oilgas/mvc/NDGathering/PipeLineRequest/CreateRequest (last visited Nov. 30, 2015); N.D. Pipeline Auth., *North Dakota Natural Gas: A Detailed Look at Natural Gas Gathering* 4 (Oct. 2013) ("During the month of August 2013, there were 4,659 non-confidential wells flaring natural

From the data readily available to the public, Commenters mapped North Dakota's wells, compressors, and processing plants to get a better sense of the wells' proximity to gas processing infrastructure. While GIS data on gathering lines were not available, one can assume that gathering lines occupy much of the distance between wells, compressor stations, and processing plants. Therefore, the distances presented here are longer than actual distance to gathering lines.

Table 8: Distance of North Dakota Wells from Nearest Compressor Station[202]

Distance to nearest compressor station	Number of wells	Percentage of total wells
Less than 3 miles	1,415	11%
3-5 miles	1,798	14%
5-10 miles	3,762	30%
More than 10 miles	5,716	45%
Total	12,691	

From these data, one can see that the majority of North Dakota wells are within 10 miles of the nearest compressor station. Given that a vast number of gathering lines run between wells, compressor stations, and processing plants (nearly 10,000 miles, as of 2014, and rapidly growing),[203] the true distance of these wells to the necessary collection and processing infrastructure is undoubtedly much less than ten miles.

In short, while a five-mile gathering line may not be economically feasible for a single well, it may be feasible if the pad has multiple wells. And while a gathering line longer than ten miles may not be feasible for a multi-well pad, it may be a feasible investment for several nearby pads.[204] Other options for gas transport and use—such as trucking CNG to nearby processing plants, using the captured gas for local energy generation, and mini-gas-to-liquids operations—are feasible at greater distances, even for single wells.[205] As described above, the technologies for CNG transportation and on-site and local uses of recovered gas are developing rapidly.
If EPA chooses to use distance as a criterion for determining technical feasibility, it must not use it as the sole factor. Rather, it must require the simultaneous consideration of other factors that affect technical feasibility of gathering systems, such as geography, capacity, and rights-of-way. Additionally, EPA must require the consideration of distance as it relates to multi-well pads and

gas in North Dakota."), *available at* https://ndpipelines.files.wordpress.com/2012/07/ndpa-detailed-look-at-gas-gathering-2013.pdf.

[202] Well locations obtained from Dep't of Mineral Res., N.D. Industrial Comm., NDIC Oil and Gas ArcIMS Viewer, https://www.dmr.nd.gov/OaGIMS/viewer.htm (accessed Nov. 24, 2015); coordinates of compressor stations obtained from N.D. Dep't of Health, Air Quality Permit Portal, http://www.ndhealth.gov/AQ/ActivePermits.aspx (accessed Nov. 24, 2015); distance calculated using proximity tool in Arc Map 10.3 (geographic coordinate system: GCS North American 1927; projection: NAD 1927 Contiguous USA Albers).

[203] DOE, Bakken Memo, *supra* note 172, at 14 ("the industry has built more than 9,555 miles of gas gathering pipe").

[204] *Id.*

[205] *Id.*

groups of wells and as it relates to other forms of capture technology, such as use as a fuel source and trucking CNG to market.

4. Conclusion

For the reasons discussed above, Commenters urge EPA to ensure that operators are carefully and rigorously evaluating more effective, available and environmentally preferable alternatives to flaring associated gas. EPA has already provided reasonable and achievable alternatives that operators must use beyond routing collected gas to a gathering line in the first instance, and states and industry are making strides toward increasing the needed infrastructure and reducing flared gas. The exemption from the REC requirement should clarify certain wording and definitional issues, while also adding provisions directing EPA and state agencies to consider claims under the exemption on a case-by-case basis. Finally, if EPA intends to use proximity as a criterion for determining technical feasibility, it should not consider it as the sole factor. The Agency should consult the detailed state databases cited above, require the consideration of other factors, and require the consideration of distance as it relates to multiple wells from both gathering lines and other capture technologies. At the same time, EPA should consider the availability of options for alternative forms of transportation and use on site or locally.

B. Phase-In Times are Unnecessary to the REC Requirements for Oil Wells.

EPA is soliciting comment on whether the well completion provisions of the proposed rule can be implemented on the effective date of the rule or whether a phase-in period is necessary. EPA states that it believes that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. We concur with this statement and conclude that phase-in of the well completion provisions is not necessary.

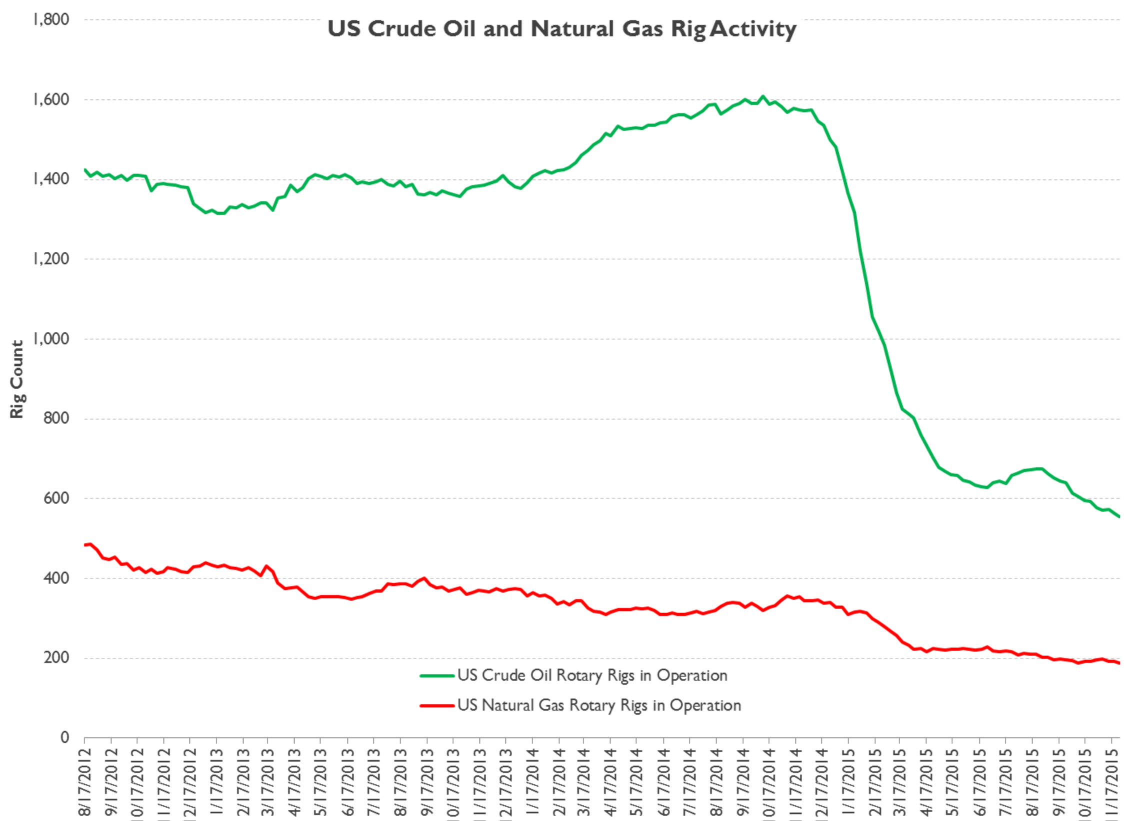
Gas well operators have been complying with the full well completions provisions of the 2012 Oil and Gas NSPS for gas wells since January of this year, and data indicate that some operators have also voluntarily complied with the REC provisions prior to the full implementation date. Data from EPA's GHG Reporting Program show that while the total number of hydraulically fractured gas well completions dropped by nearly 30% from 2011 to 2014, the number of completions with REC has decreased by only 5% in that time period, meaning that the percentage of completions with REC has grown, from 51% of completions in 2011 to 67% in 2014.[206] This indicates that oil and gas operators have been preparing to comply with the REC provisions of the 2012 NSPS and that sufficient equipment is available to perform RECs.

The slowdown in drilling and completion of gas wells also means that there is a surplus of REC equipment available, which can be shifted to completion of oil wells. Since the 2012 NSPS went into effect in August of 2012, the count of rigs drilling gas wells has dropped due to low gas prices from 484 rigs running the week of 8/17/2012 to 189 the week of 11/25/2015. While the number of rigs drilling oil wells initially grew during this period, from 1425 rigs running the week of 8/17/2012 to a high of 1609 the week of 10/10/2014, low oil prices have since caused the oil well rig count to also drop steeply, with only 555 rigs running the week of 11/25/2015

[206] 2014 GHGRP Subpart W data. The GHGRP data represents only a subset of total completions due to reporting thresholds.

(Figure 8).[207] The Energy Information Administration's (EIA) Short Term Energy Forecast (STEO) for November forecasts that monthly crude oil production, which began to fall in the second quarter of 2015, will continue to decline through late 2016.[208] The International Energy Agency's (IEA) Oil Market Report for November similarly finds that US crude oil production has been declining, and forecasts that even steeper declines lay ahead.[209] IEA's report also estimates that in October 2015 only 800 new wells were completed, which is less than half the number of wells completed in the same month a year earlier.[210] Given these forecasts, there should be no short- to medium-term shortages of REC equipment, and industry will have sufficient lead time to construct additional REC equipment, if needed in the long-term.

Fig. 8: U.S. Crude Oil and Natural Gas Rig Activity (Baker Hughes North America Rig Count)



Oil and gas operators have had more than two years to construct additional REC equipment since the 2012 NSPS was finalized in August 2012, and the requirements to perform RECs on gas

[207] Baker Hughes North America Rig Count, available at <http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother>
[208] U.S. Energy Information Administration. *Short-Term Energy Outlook, U.S. Petroleum and Other Liquids.* 10 November 2015. Available at <http://www.eia.gov/forecasts/steo/report/us_oil.cfm>
[209] International Energy Agency. *Oil Market Report.* 13 November 2015. Available at <https://www.iea.org/media/omrreports/fullissues/2015-11-13.pdf>
[210] *Id.*

wells went into effect in January 2015. This long phase-in time for gas wells, combined with the significant slowdown in drilling of both gas and oil wells, indicates that there should be sufficient REC equipment available when the new NSPS goes into effect, such that a phase-in time for performing RECs on oil wells is not necessary. Even if drilling rates rebound more quickly than predicted before the effective date of the rule, a phase-in time should not be necessary, given that REC equipment is relatively simple to construct and can be readily assembled when needed, as we described in our previous comments on the 2012 NSPS.
In sum, a sufficient supply of REC equipment should be available by the effective date of the proposed rules, and therefore a phase-in time for the well completion provisions is not necessary.

C. GOR Exemption Threshold

EPA has proposed that wells with gas-to-oil ratios (GOR) less than 300 scf per bbl would not be subject to REC requirements. As the rationale for setting this threshold, EPA states that "we set a of GOR of less than 300 scf/barrel as the threshold under which an oil well completion would not be reasonably capable of capturing and controlling emissions" due to the fact that such a well "will not likely have enough gas associated that it can be separated." However, the proposed rule already exempts wells from the REC requirements if a separator cannot function. As such, the proposed GOR exemption is duplicative and not necessary.

Nevertheless, if EPA decides to retain this exemption, we propose an alternate formulation, as described below. To determine the effect of this exemption, we analyzed data from the production database DI Desktop for approximately 20,000 oil wells (i.e., production type "oil" or "O&G") that were completed in 2014. For individual wells, potential completion flowback methane emissions were assumed to equal three days of practical initial gas production (2^{nd} month of reported production) with 78.8% methane content. Table 9 summarizes the number of wells, average potential emissions, and total potential emissions of wells subject to or exempt from REC requirements under different exemptions. If wells with GOR less than 300 scf per bbl are exempt, 70% of wells and 99.61% of emissions would still be subject to the REC requirements, notwithstanding other exemptions. EPA requests comment on an exemption for wells with average daily production less than 15 bbl oil equivalents (BOE) per day. Under this exemption, a marginally higher percentage of wells and emissions would be subject to the REC requirements than under the GOR exemption. If wells were exempted for either the GOR or production thresholds, a slightly lower percentage of wells and emissions would be subject to the REC requirements. The <300 scf per bbl GOR threshold is reasonable for decreasing the number of subject wells with minimum impact on the coverage of total emissions, but it results in the exemption of about 2% of wells with emissions exceeding 1 ton of methane. These exempt, relatively high emission wells are primarily those with very high oil production and >100 scf per bbl GOR.

An alternative exemption based on gas production is more effective for reducing emissions because potential emissions are more directly related to gas production, but depend on the interaction of GOR and oil production. For example, an exemption for wells with less than 10 Mcf gas per day would result in 58% of wells and 99.91% of emissions being subject to the REC requirements. We recommend that EPA consider exempting wells that produce less than 10 Mcf gas per day instead of those with less than 300 scf per bbl GOR or 15 BOE per day. Operators likely can predict the initial gas production of a well more accurately than GOR, which further increases the value of basing the exemption on gas production. EPA Greenhouse Gas Reporting data includes 28 records of hydraulically fractured gas well completions with measured flowback rates below 10 Mcf per day that recovered gas to sales; this supports the feasibility of RECs for wells with production equal or greater than 10 Mcf per day.

Table 9: Percent of Oil Wells and Completion Emissions subject to REC requirements Under Different Exemptions

Exemption		2014 Well Count	2014 Average Potential Emissions (tons CH_4 well^{-1})	2014 Total Potential Emissions (tons CH_4 yr^{-1})
	All wells	19,771	22.9	398,382
<300 scf/bbl GOR	subject	13,833	32.3	396,809
	exempt	5,938	0.3	1,572
	% subject	70%		99.61%
<15 bbl/day BOE	subject	14,454	30.5	397,386
	exempt	5,317	0.2	995
	% subject	73%		99.75%
<300 scf/bbl GOR or <15 bbl/day BOE	subject	11,374	39.1	395,959
	exempt	8,397	0.3	2,423
	% subject	58%		99.39%
<10 Mcf/day gas	subject	12,445	36.1	398,031
	exempt	7,326	0.1	351
	% subject	63%		99.91%

D. Separator Feasibility

In section VIII.F.3. of the preamble to the proposed rules, EPA states that, "Recent information indicates that some wells, because of certain characteristics of the reservoir, do not need to employ a separator." In this context, EPA is soliciting comments on, "(1) the role of the separator in well completions and whether a separator can be employed for every well completion; and (2) the appropriate relationship of the separator in the context of our requirements that cover a very broad spectrum of wells."

EPA provides no additional details regarding the types of wells or particular "characteristics of the reservoir" for which a separator is not needed, including whether or not the wells in question are oil wells. Without additional details, it is not possible to thoroughly evaluate these claims. Critically, EPA has not provided any emissions data from completions on these wells where a separator is supposedly not needed. Moreover, the issue of whether or not a separator is "needed" is irrelevant – EPA has determined that the BSER for well completions is the use of REC separation equipment with combustion. In the proposed rule, EPA states that "combustion alone would not represent the BSER for well completions because, although the emissions reduction would be equal to the REC and completion combustion device combination (i.e., 95 percent control), the opportunity to realize gas recovery would be minimized and the generation of secondary combustion related emissions would be increased." In other words, EPA has already determined that forgoing the use of a separator is not BSER.

The practice described by EPA in section VIII.F.3 for which a separator is not needed, whereby operators, "direct the flowback to a pit and…combust gas contained in the flowback as it emerges from the pipe" is precisely the practice that RECs are designed to replace. In fact, this completion practice is the same as that described in EPA's Natural Gas STAR "Lessons Learned" fact sheet for RECs, as the problematic completion practice that leads to high emissions:

> Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids and sand are captured and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from one day to several weeks during which time a substantial amount of gas may be released to the atmosphere or flared.[211]

Operators must not be exempted from the REC requirements simply on the basis that they choose not to employ a separator for reasons unrelated to emissions reductions, as EPA has already determined in its BSER analysis. Although it may not be possible for a separator to be employed for every well completion due to technological reasons such as gas quantity or pressure, the proposed rule already excuses operators from performing a REC in situations in which it is technologically infeasible for a separator to function.

V. Pneumatic Pumps

A. EPA's Proposal

EPA has proposed the first Federal standards for air pollution from pneumatic pumps. Pneumatic pumps use the energy of high-pressure natural gas to pump a liquid, typically venting low-pressure natural gas to the atmosphere. The proposed measures would apply to new and modified pneumatic chemical injection pumps and pneumatic diaphragm pumps.[212] Notably, they do not apply to glycol assist pumps,[213] which often vent *via* the glycol regenerator, so the methane and other pollutants from the natural gas powering the pump is ultimately emitted from the vent stack of the dehydrator instead of directly from the pump.[214] In section V.C, we will discuss EPA's decision to exempt glycol circulation pumps from the standards. Otherwise, we will generally

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[211] U.S. Environmental Protection Agency. 2011. *Lessons Learned from Natural Gas STAR Partners: Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells.* Available at < http://www3.epa.gov/gasstar/documents/reduced_emissions_completions.pdf>

[212] Proposed 40 C.F.R. § 60.5365a(h).

[213] 80 F.R. at 56,627.

[214] See API, "Technical Review of Pneumatic Controllers," at 12 (Oct. 10, 2011), available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0557-0006. See also Kimray, Inc., "Glycol Pumps Product Bulletin," (July 2011), at 3. Available at: https://kimray.com/Portals/0/Documents/PB0004.pdf.

use the term "pneumatic pumps" to refer to pneumatic chemical injection pumps and pneumatic diaphragm pumps collectively.

We support the proposed measures, which would require that a) new and modified pneumatic pumps at gas processing plants emit zero natural gas,[215] and b) new and modified pneumatic pumps at other sites reduce natural gas emissions, provided a control device is available on site.[216] Pneumatic pumps are estimated to currently emit over 113,000 metric tons of methane per year,[217] and EPA estimates that the proposed measures will reduce emissions by over 32,000 short tons of methane and 9,000 short tons of VOC in 2025.[218] The measures that EPA is proposing will be very inexpensive. EPA estimates that the annual cost of routing emissions from a pump to a control device or VRU is $285.[219] Based on these costs, EPA estimates that these standards will reduce nationwide emissions for $157 per short ton of methane abatement, or $566 per short ton of VOC abatement.[220] For some types of pumps, routing emissions to a VRU will result in net cost savings.[221]

However, EPA must strengthen its proposal in order for the standards to achieve BSER. First, outside of processing plants, EPA's proposal only requires control of pneumatic pumps at sites with control devices, and does not require control at sites that do not have a control device, but do have a VRU or equipment installed which could use the gas vented from the pneumatic pump, such as a heater or boiler. EPA acknowledges that gas from pneumatic pumps can readily be routed to a VRU,[222] and the proposed standards allow gas from pumps to be routed to a process as an alternative to routing to a control device.[223] Nevertheless, operators are only required to control emissions from pneumatic pumps if a control device is present on site. In fact, pneumatic pumps outside of gas processing plants are only affected facilities if a control device is present on site.[224] Therefore, operators of pneumatic pumps at wellpads with VRUs or other suitable processes such as boilers, but without control devices, will not be required to control emissions from pumps, even though the emissions could readily be routed to the VRU or process.

Second, EPA does not require the use of electric pumps at non-processing plant sites, such as compressor stations, large production sites, and sites of all sizes in urban areas, where electricity

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[215] Proposed 40 C.F.R. § 60.5393a(a).
[216] Proposed 40 C.F.R. § 60.5393a(b)(4).
[217] EPA, U.S. GHG Inventory (2015), Annex 3, Tables A-129 and A-149, *available at* http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.
[218] TSD at 177.
[219] TSD at 161.
[220] Calculated, using the single-pollutant methodology, from data in Table 7-19 of the TSD (at 177).
[221] TSD at 175.
[222] TSD at 162 ("Use of a vapor recovery technology has the potential to reduce the emissions from natural gas-drive pumps by 100 percent…").
[223] Proposed 40 C.F.R. § 60.5393a(b).
[224] Proposed 40 C.F.R. § 60.5365a(h)(2). While § 60.5393a(b)(2) of the proposed standards lists requirements that operators of affected pneumatic pumps at sites without control devices submit certification that no control device is present, it appears that this provision would never be used since these pumps are not affected facilities.

is available, either from the grid or generated on-site. Electric pumps, including solar-powered pumps, are available for chemical injection.[225] Electric glycol circulation pumps are also available. According to API, electric injection and glycol circulation pumps are more efficient than using instrument air to drive pneumatic pumps.[226] These non-emitting technologies are preferable to routing emissions from pumps to control devices.

B. Suggested Approach

Similar to the approach we suggest for pneumatic controllers below in Section VI.D, EPA should first require non-emitting pumps at facilities where electricity is available (from the grid or generated on site). Electricity is generally available at large compressor stations, large production facilities and sites of all sizes in urbanized areas. Alternatively, operators should route emissions to a process instead of installing zero-bleed technologies. The standards should require operators of sites without access to electricity to route emissions from pneumatic pumps to a process such as to a VRU or fuel line, if available on site. If routing to a process is not available at a site, operators should route emissions to a control device, though this approach is less protective than non-emitting technology (electric pumps) or routing to a VRU or process.

We suggest that all new and modified natural gas-driven pneumatic pumps at non-gas processing plants be treated as affected facilities, so that EPA can collect data on all pneumatic pumps using the provisions of proposed § 60.5393a(b)(2) and § 60.5420(b)(8). These affected pneumatic pumps should be required to emit no natural gas at sites with electricity, or route all emissions to a VRU or process if available on site. If neither electricity nor a VRU or process is available at a site, operators should route all emissions from pneumatic pumps to a control device if one is available on site. As many operators use solar-powered pneumatic pumps, EPA should consider the potential for solar on-site power as available electricity. EPA could develop a map based on solar radiation to determine which areas of the country have the potential for continuous operation of solar-powered pneumatic pumps.

C. Glycol circulation pumps

Glycol assist pumps, referred to as "Kimray Pumps" in the GHG Inventory, are estimated to emit 184,773 metric tons of natural gas per year.[227] While control of emissions from these pumps is more complex than control of emissions from chemical injection pumps (because the natural gas used to drive the pump is emitted via the dehydrator vent stack), there are a number of options to reduce emissions from these pumps. As EPA notes, electrification is an option for these pumps.[228] A secondary option is the use of a low pressure glycol separator, which can separate

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[225] Solar powered chemical injection pumps are ubiquitous in locations as far north as Pennsylvania, suggesting that the technology is mature enough to be used in northern locations with cold winter weather.

[226] API, *supra* note 214.

[227] U.S. GHG Inventory (2015), *supra* note 217, Tables A-129 and A-136.

[228] 80 Fed. Reg. at 56,627.

methane-rich gas from the glycol before it enters the regenerator.[229] If this is done, the gas can be used to fuel the boiler on the regenerator or otherwise consumed for fuel on-site.[230]

For gas processing plants and sites where electricity is present, EPA should require that new and modified glycol circulation pumps not emit any natural gas, since electric pumps are available for this purpose. EPA should consider requiring the use of low pressure glycol separators at other sites, since the methane separated from the glycol in this way can typically be directed to the boiler or the regenerator. It is important to consider that some natural gas dehydrators have emissions controls installed that control emissions of VOC, but do not control emissions of methane. If vented natural gas from a glycol circulation pump is routed into a glycol regenerator, the methane from the natural gas may be emitted to the atmosphere even if there are VOC controls on the dehydrator.

D. Concerns about EPA's methodology for estimating emissions reductions

We note here two errors in the methodology EPA uses to calculate emissions reductions in future years resulting from the proposed standards. The errors we note do *not* affect the selection of regulatory options, but we believe the Agency should correct the methodology it uses moving forward.

The first is specific to the calculation of emissions reductions from control of pneumatic pumps. In order to estimate the number of new chemical injection pumps (CIPs) installed every year, EPA calculated both the growth in the population of CIPs in use and the rate of replacement of the CIP population. To calculate the rate of replacement, EPA used the following approach.

> To forecast the count of CIPs replaced in a *typical* year, age and count of gas and oil wells for 2013 were extracted from DI Desktop®. The age of the pneumatic pump was assumed to be the age of the well. Based on expert judgment, the average lifetime of a pneumatic pump was assumed to be 10 years. *Therefore, a portion of CIPs that reached 10 years in a particular year were assumed to be replaced that year*.[231]

EPA is therefore assuming that CIPs – and more importantly, oil and gas wells – have a fixed and certain ten year lifetime. One important implication of this is that it suggests that the whole fleet of wells and ancillary equipment in service today turns over entirely in ten years (and has half turned over in just five years). If true, this would mean that new source standards would lead to a clean up of *all* oil and gas production sites in a fixed and certain time.

Unfortunately, this is not the case. Even if an "average" well lasts ten years, many last far longer. The population of wells drilled in a given year that are still in service declines over time in a more exponential fashion. This means that some portion of those wells will be in service many years into the future. Indeed, wells are in service today that were originally drilled decades ago.

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[229] Kimray, Inc., "Glycol Pumps Product Bulletin," (July 2011), at 3, *available at* https://kimray.com/Portals/0/Documents/PB0004.pdf.
[230] *Id.*
[231] TSD at 148 (emphasis added).

We urge EPA to use a more realistic approach to the calculation of turnover / decommissioning of oil and gas facilities.

The second concern is with the general methodology that the RIA uses to calculate the emissions reductions from equipment standards in 2020 and 2025. This concern applies to the calculation of emissions reductions due to the standards on other sources in addition to the standards for pneumatic pumps. In its RIA, EPA analyzes the emission reductions the proposed rule would achieve in 2020 and 2025, noting that 2020 "represent[s] the first full year of compliance" and that the rule's emission reduction benefits will accumulate over the period of 2020-2025.[232] This is puzzling and incorrect: under section 111, a new source performance standard under section 111 applies to any source "the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source."[233] EPA published its proposed regulations in the Federal Register on September 18, 2015, so any source constructed or modified after that date will have to comply with the final performance standards. By analyzing 2020 as the "first full year of compliance," EPA appears to have omitted nearly four and a half years' worth of emission reductions from its calculation of the rule's benefits. We urge the agency to amend this error in its analysis of the final rule.

VI. Pneumatic controllers

A. Summary

Pneumatic controllers account for a very large quantity of the oil and gas sector's methane pollution. EPA's GHGI estimates 2013 emissions of 1,004,907 metric tons of methane from these devices, or 14% of all methane from the oil and gas sector.[234] This is likely an underestimate of actual emissions.

EPA is proposing methane standards for new and modified continuous-bleed pneumatic controllers in the oil production, natural gas production, and natural gas processing segments. These standards are identical to the current VOC emission standards for new and modified controllers in these segments. Additionally, EPA proposes standards for methane and VOC emissions from new and modified continuous-bleed pneumatic controllers in the natural gas transmission and storage segments of the industry. Emissions from these devices are largely unregulated, as EPA has not previously set standards for emissions from these devices.
The proposed emissions standards for the transmission and storage segment extend the very feasible and highly cost-effective approach that EPA and some states have taken to reduce harmful emissions from these devices. However, the proposed standards fall short of BSER for two reasons.

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232 RIA at 3-9.
233 42 U.S.C. § 7411(a)(2).
234 2013 GHGI, Annex 3, Tables A-129, A-136, A-137, and A-149, *available at* http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Pneumatic controller emission calculations are based on Pneumatic Controller Vent potential emissions with Reductions Derived from the Natural Gas STAR Program subtracted to get net emissions.

First, the proposed standards for continuous-bleed pneumatic controllers do not reflect BSER, because, for most facilities, they only limit emissions by requiring that newly installed continuous-bleed controllers be "low-bleed," meaning that they emit, according to a manufacturer's specification, six standard cubic feet per hour (scfh) or less. While lower emitting than "high-bleed" pneumatic controllers, low-bleed controllers often improperly emit at a higher rate than they are designed to emit, and above the six scfh threshold. EPA's standards need to reflect that emissions from all types of pneumatic controllers can be essentially eliminated at many types of facilities using two basic approaches:

- Use inherently zero-emitting technologies, such as air-driven pneumatic controllers or electric controllers, instead of natural gas-driven pneumatic controllers.

- Reduce emissions from natural gas driven pneumatic controllers by routing bleed gas to a process, such as a VRU or on-site fuel line, or a control device.

Accordingly, the emissions from low-bleed controllers – due to both their normal operations and improper functioning – can be minimized. Nevertheless, EPA's proposal only requires zero-emitting technologies for new continuous-bleed pneumatic controllers at gas processing plants and fails to require them at other facilities, despite the fact that they are feasible at many other sites. And although routing emissions to a process or control device would be feasible at many sites, EPA never requires this approach. Finally, EPA's proposal does not require operators to ensure that pneumatic controllers are performing properly, so emissions from improperly functioning devices will continue indefinitely in many cases.

Second, the proposed standards only apply to continuous-bleed pneumatic controllers and thus do not address harmful emissions from intermittent-bleed pneumatic controllers, which are a very significant source of methane emissions. The two approaches described above – inherent zero-emitting technologies and route to process/control – can also apply to intermittent-bleed controllers, so emissions from these devices can be essentially eliminated at many sites. Additionally, as outlined above for continuous bleed devices requirements should apply to intermittent devices in all sectors of the value chain and operators should be required to ensure the devices are properly functioning as part of compliance demonstrations.

In sum, EPA must strengthen the proposed standards, as discussed in detail below, by requiring operators to use zero-emitting technologies, such as air-driven or electric controllers, at oil and gas facilities where electric power is available. At facilities where zero-emitting technologies are not feasible, operators should be required to capture emissions from all gas-drive pneumatic controllers and route them to a VRU or use them for fuel gas, if appropriate equipment is available on site. If this equipment is not available but a control device exists on site, emissions from all pneumatic controllers should be routed to that device. Finally, for those sites where none of these approaches are feasible, EPA should require that any pneumatic controllers (both continuous-bleed and intermittent-bleed) be low-emitting, and require that operators regularly inspect and measure emissions from controllers to ensure that they are performing as such.

B. Current emissions

According to the most current GHGI, pneumatic controllers emitted over one million metric tons of methane in 2013.[235] As shown in Table 10, the GHGI reports that these emissions are predominantly in oil and natural gas production, and natural gas transmission and storage.

Table 10: Emissions from Pneumatic Controllers by Oil and Gas Industry Segment

Segment	Net Methane Emissions from Pneumatic Controllers (2013)
Gas Production	539,106
Oil Production	220,600
Processing	1,597
Transmission and Storage	243,604
TOTAL	**1,004,907**

Source: EPA, US Greenhouse Gas Inventory, 2015 Edition

As discussed below, there is evidence from recent studies and reports that the GHGI estimate is probably too low, primarily because its data are based on studies that undercounted the number of pneumatic controllers in service in the oil and gas industries. These studies have also shown that pneumatic controllers often improperly emit more, or far more, than designed to emit. In order to prevent harmful pollution, EPA must consider this information and finalize standards that ensure pneumatic controller emissions are truly minimized.

1. <u>Data for pneumatic controller counts and overall emissions</u>

Data from the Reporting Program and several recent studies strongly suggest that the GHGI estimate for oil and gas production pneumatic controllers is too low due to an undercount of the number of controllers in service. As a result, the GHGI estimate for emissions from these controllers is also too low. While the GHGI reports that pneumatic controllers in the production segments of the oil and natural gas sector emitted 759,706 metric tons of methane in 2013,[236] the Reporting Program reports 1,002,025 metric tons of emissions from pneumatic controllers in these segments in 2013.[237] Both the Reporting Program and the GHGI use emissions factors derived[238] from the EPA / Gas Research Institute study (EPA/GRI study) of natural gas industry methane emissions published in the 1990s.[239] Since the GHGI and the Reporting Program use the same emissions factors but the Reporting Program reports larger emissions, the difference is in the underlying pneumatic controller count data. In this respect, the Reporting Program is more accurate than the GHGI, since the Reporting Program uses actual counts of controllers by oil and gas producers to calculate emissions, while the GHGI controller count estimates are based on extrapolation of a count from a small sample of facilities carried out as part of the EPA/GRI study some years ago. In addition, the counts from the Reporting Program – even though they are

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[235] *Id.*
[236] *Id.* at A-129 and A-149.
[237] US Environmental Protection Agency. Greenhouse Gas Reporting Program. Petroleum and Natural Gas Systems. W_PNEUMATIC_DEVICE_TYPE. Available at: http://www.epa.gov/enviro/facts/ghg/customized.html.
[238] *See* Ex. VI-1, Clean Air Task Force, "Comments on Expert Draft of 2014 US Greenhouse Gas Inventory," p. 3.
[239] GRI-EPA. (June 1996). "Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatics." Available at: http://epa.gov/gasstar/documents/emissions_report/12_pneumatic.pdf.

higher than the GHGI counts – are still an underestimate of pneumatic controllers in service in oil and gas production, because many oil and gas production facilities do not report data on pneumatic controller emissions to the Reporting Program.[240]

Allen *et al*. (2013) reports results on measurements of emissions from 305 pneumatic controllers at 150 natural gas production sites,[241] finding that emissions from these controllers were likely higher than reported in the GHGI: Allen *et al*. (2013) estimate nationwide emissions were 518 – 826 Gg methane from pneumatic controllers at natural gas well sites in 2012,[242] while the latest edition of the GHGI reports net emissions of 557 Gg of methane from natural gas production in that year.[243] Note that the figure from Allen *et al*. (2013) represents emissions only from natural gas wellpads, while the GHGI figure represents emissions from natural gas wellpads and natural gas gathering facilities. Alarmingly, Allen *et al*. reports that pneumatic controllers that site operators classified as "low-bleed controllers" and intermittent-bleed controllers emitted on average of 270% and 29%, respectively, more methane per controller than the emissions factor used by EPA to calculate emissions for the GHGI and the Reporting Program.[244] If the Reporting Program count data is used along with the emission factors from Allen *et al*. (2013), the resulting estimate of emissions from pneumatic controllers at oil and natural gas production sites would increase by over 30% to 1,290,730 metric tons of methane for 2013.[245]

A 2015 study by the same research team that produced the 2013 Allen study reports the results of a new set of measurements of emissions from 377 pneumatic controllers at 65 oil and natural gas production sites (largely natural gas sites).[246] These measurements indicated a lower overall average emission rate for individual pneumatic controllers (5.5 scfh of whole gas) than reported by the earlier study, Allen *et al*. (2013), the GHGI or the Reporting Program.[247] Allen *et al*. (2015) attribute the lower emissions per controller (as compared to Allen *et al*. (2013)) primarily to the large number of controllers they observed that did not emit. Allen *et al.* (2015) also reports that the wellsites they surveyed had 2.7 pneumatic controllers per well, a much higher figure than the activity ratio used by the GHGI of 1.0 pneumatic controller per well.[248] As Allen *et al*. (2015) discuss, it is possible that well site operators are often not counting intermittent-bleed pneumatic controllers that rarely actuate (such as controllers for emergency shut-off devices) in

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[240] Oil and gas producers which calculate emissions of less than 25,000 tons of carbon dioxide equivalent per year from sources in a single oil and gas producing basin do not report emissions to the Reporting Program. While some natural gas gathering facilities report combustion emissions to the Reporting Program, methane emissions from leaks and process venting, including pneumatic controllers, are not currently reported to the Reporting Program.

[241] Ex. VI-2, Allen, D.T., *et al.* (2013), "Measurements of methane emissions at natural gas production sites in the United States," *Proc. Natl. Acad. Sci. USA* 110(44):17768-17773.

[242] *Id*.

[243] EPA, *supra* note 234.

[244] Allen, D.T., *et al.* (2013), *supra* note 241.

[245] *See* McCabe, David, et al. (2014) "Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry," at 56, available at: http://www.catf.us/resources/publications/files/WasteNot.pdf ("Waste Not").

[246] Ex. VI-3, Allen D.T. *et al.* (2015), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environ. Sci. Technol*. **49**, 633−640.

[247] *Id.*

[248] *Id.*

their counts of pneumatic controllers for such purposes as greenhouse gas reporting.[249] Previous research efforts may have similarly undercounted these controllers. When these controllers are included, average emissions per controller decreases, but Allen et al. (2015)'s finding regarding pneumatic controller counts also suggests that nationwide pneumatic controller emissions are higher than reported in the GHGI, even considering the lower emissions per controller reported in that study.[250] However, as we discuss below, emissions from controllers that rarely actuate can be quite significant due to improperly functioning equipment.

2. Data for emissions from specific types of pneumatic controllers

Data from the Reporting Program provides information on the distribution of emissions by type of pneumatic controller. As shown in Table 11, the great majority of reported emissions from oil and natural gas production pneumatic controllers originates from intermittent-bleed controllers. Pneumatic controller emissions reported to the Reporting Program from natural gas transmission and storage facilities are very low, most likely because so many of those facilities fall below the reporting threshold for that program (25,000 metric tons CO_2e per year). Nevertheless, emissions from intermittent-bleed devices represent 40% of reported natural gas transmission and storage pneumatic controller emissions.

Table 11: Emissions by Type of Pneumatic Controller

Reporting Program 2014 reported emissions[251]		Metric tons methane			
		Low Bleed	Intermittent Bleed	High Bleed	**Total**
Production	Metric tons methane *(%)*	32,807 *(12%)*	849,096 *(85%)*	120,696 *(3%)*	**1,002,599**
	Number of controllers *(%)*	192,674 *(26%)*	521,318 *(71%)*	24,344 *(3%)*	**738,336**
Transmission and Storage*	Metric tons methane *(%)*	303 *(2%)*	4,991 *(40%)*	7,056 *(57%)*	**12,350**
	Number of controllers *(%)*	1,397 *(8%)*	13,186 *(77%)*	2,444 *(14%)*	**17,027**

Source: EPA Greenhouse Gas Reporting Program, 2014 data.

* The Reporting Program is always an underestimate of national emissions, because some facilities fall under the 25,000 metric ton CO2-e threshold and therefore do not have to report. We believe that the Reporting Program data

[249] *Id.*

[250] The GHGI reports net methane emissions from natural gas production of 539 Gg of methane in 2013, from 459,304 pneumatic controllers. *See* EPA, supra note 234, at Tables A-149 (pneumatic controller methane emissions) and A-133 (pneumatic controller population count). This equates to 1.2 metric tons of methane per year per controller, or 7.0 scfh of methane. Allen, *et al.* (2015), *supra* note 246, reports that emissions per controller are 4.9 scfh of methane, but also reports that there are 2.7 pneumatic controllers per well, compared to the 1.0 controllers per well which forms the basis of the GHGI's calculation of the number of pneumatic controllers in service in natural gas production. The higher figure of controllers per well suggests that around 1,240,000 controllers are in use at natural gas production sites. Combining this figure with the 4.9 scfh figure for each controller from Allen *et al.* (2015) suggests that natural gas production pneumatic controllers could emit 1,010,000 metric tons of methane per year. This also assumes that production controller count is dominated by wellpads.

[251] Reporting Program, *supra* note 237.

for the Transmission and Storage segments is an even more significant underestimate than most other segments, because the sector consists of a large number of small facilities.

As mentioned above, Allen *et al*. (2013) reported that emissions from low-bleed controllers and intermittent-bleed controllers in natural gas production emitted on average 270% and 29%, respectively, more methane per controller than the emissions factor used by EPA to calculate emissions for the Reporting Program.[252] This suggests that nationwide emissions for these types of controllers in the production segment are higher, by similar percentages, than reported by the Reporting Program. This would make the strikingly high portion of emissions from intermittent-bleed controllers even higher.

Allen *et al*. (2015) reports very low emissions per "intermittent vent" pneumatic controller – 2.2 scfh.[253] While this figure is lower than the emissions factor for intermittent-bleed controllers used in the GHGI and Reporting Program, these numbers are not susceptible to an apples-to-apples comparison, primarily because Allen *et al*. (2015) treated many devices that were probably functioning improperly (and therefore high-emitting) intermittent-bleed controllers as continuous-bleed controllers in their analysis.[254]

3. Specified bleed rate and behavior vs. observed emissions

Several recent studies report that pneumatic controllers often emit more than they are designed to emit.

- Allen *et al*. (2015). As part of this study, an expert group reviewed the behavior of the 40 highest emitting controllers in the study, which were responsible for 81 percent of the emissions from all controllers in the study (377 controllers). The expert group concluded that "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."[255] Of the forty high-emitting controllers, 28 were judged to be operating incorrectly due to equipment issues. The study reported that many devices observed to actuate, i.e. intermittent-bleed controllers, also had continuous emissions.

- Allen *et al*. (2013). As noted above, this study reported that emissions from low-bleed pneumatic controllers were 270% higher than EPA's emissions factor for these devices – 5.1 scfh.[256] Many low-bleed controllers are specified to emit far less than this: EPA's Gas Star program has documented many low-bleed controller models with bleed rates of less than 3 scfh,[257] and of course the emissions factor used by EPA for low-bleeds (1.39 scfh)[258] implies that many low-bleeds are expected to emit at a very low level. Assuming that some low-bleed controllers are performing as specified, the high emission rate

[252] Allen, *et al*. (2013), *supra* note 244.
[253] Allen, *et al*. (2015), *supra* note 246.
[254] Allen, *et al*. (2015), *supra* note 246.
[255] Allen, *et al*. (2015), *supra* note 246.
[256] Allen, *et al*. (2013), *supra* note 244.
[257] USEPA, Lessons Learned from Natural Gas STAR Partners, "Pneumatic Devices In The Natural Gas Industry," at Appendix 1. Available at: http://epa.gov/gasstar/documents/ll_pneumatics.pdf.
[258] 40 C.F.R. § 98.233(a).

observed by Allen *et al*. (2013) implies that many "low-bleed pneumatic controllers" are in fact emitting more than the design threshold of 6 scfh for low-bleeds[259] – or much more than 6 scfh – simply to raise the average emission rate to 5.1 scfh.

- City of Fort Worth Study. The Fort Worth Study examined emissions from 489 intermittent pneumatic controllers using infrared cameras, Method 21, and a HiFlow sampler for quantification, and found that many of these controllers were emitting constantly and at very high rates, even though these devices were used to operate separator dump valves and were not designed to emit in between actuations.[260] Average emission rates for the controllers in the Fort Worth Study approached the average rate of a high-bleed pneumatic controller. According to the study authors, these emissions were frequently due to improperly functioning or failed controllers.[261]

- British Columbia Study. The Prasino study of pneumatic controller emissions in British Columbia also noted the potential for maintenance issues to lead to abnormally high bleed rates.[262] Although the researchers did not identify a cause for these unexpectedly high emission rates, the results are consistent with the observation that maintenance and operational issues can lead to high emissions.

- The Carbon Limits Study. The Carbon Limits Report confirms these findings and also concludes that LDAR programs may help to identify other improperly functioning devices like pneumatic controllers.[263]

4. Summary.

EPA reports indicate that emissions from natural gas-driven pneumatic controllers are very large, probably over one million metric tons of methane per year, and recent independent research shows that these figures are likely an underestimate of current pollution from these devices. Intermittent-bleed pneumatic controllers contribute a large portion of these emissions. Furthermore, research indicates that pneumatic controllers often function improperly and, as a result, emit significantly more than they are designed to emit.

C. EPA's Proposal

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[259] *Id.* § 60.5390(c)(1).
[260] ERG and Sage Environmental Consulting, LP, *City of Fort Worth Natural Gas Air Quality Study, Final Report.* (July 13, 2011) ["Fort Worth Study"], *available at* http://fortworthtexas.gov/gaswells/default.aspx?id=87074.
[261] *See id.* at 3-99 to 3-100 ("Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually").
[262] *See* Ex. VI-4, The Prasino Group, *Determining bleed rates for pneumatic devices in British Columbia; Final Report* (Dec. 18, 2013), at 19 ("Certain controllers can have abnormally high bleed rates due to operations and maintenance; however, these bleed rates are representative of real world conditions and therefore were included in the analysis.").
[263] Ex. VI-5, EDF, Oil and Natural Gas Sector Leaks Peer Review Responses of Environmental Defense Fund, June 16, 2014 at 17.

In the current draft rule, EPA has proposed to augment the VOC standards for pneumatic controllers issued in 2012. Those standards generally require that new and modified *continuous-bleed* controllers in the oil and natural gas production segment of the industry emit no more than six scfh of natural gas, and that new and modified continuous-bleed controllers at gas processing plants emit no natural gas. EPA now proposes methane standards for these controllers, and also proposes methane and VOC standards for continuous-bleed pneumatic controllers in the natural gas transmission and storage segments of the industry. Like the standards for oil and natural gas production, these new standards for transmission and storage will require that new and modified continuous-bleed pneumatic controllers emit no more than six scfh.

These augmented standards build upon a proven and successful approach taken by EPA and various states to reduce emissions from continuous-bleed pneumatic controllers. As EPA's calculations show, these standards are extremely cost-effective: EPA calculates that the standards will reduce methane emissions at a cost of only $9 per short ton of methane abated, and this calculation does not include any accounting for savings or increased revenue by industry due to avoided loss of natural gas, since EPA concludes that operators of transmission and storage facilities will not typically directly receive more revenue as a result of lowered loss of natural gas.[264] Likewise, analysis previously carried out by EPA for the 2012 rules showed that the methane and VOC standards for pneumatic controllers in the production and processing segments are also cost-effective – in fact, the standards for the production segment have negative costs.[265] As we have documented previously, calculations by states and in other reports have confirmed these low costs.[266]

The record also shows that it is very feasible to use low-bleed controllers instead of high-bleed controllers. For example, Colorado standards first required operators to replace existing high-bleed controllers with low-bleed controllers in the urban portions of the Denver-Julesberg basin in 2009.[267] The 2009 Colorado standard contained provisions allowing operators to keep high-bleed controllers in service if they showed that doing so was necessary for "safety and/or process purposes."[268] *Not a single operator requested such an exemption,*[269] and there is no evidence indicating that these requirements have caused any operational problems. These replacements have reduced annual methane emissions in the Denver-Julesberg basin by thousands of tons per year.[270] Certainly, EPA's proposal to require use of low-bleed controllers within the transmission

[264] 80 Fed. Reg. at 56,623. This figure attributes all costs to methane reductions only. As discussed throughout the preamble for the standards proposal, if costs are attributed using the multi-pollutant approach, they will be even lower.

[265] EPA found that requiring low-bleed controllers for oil and gas production would have negative VOC emission abatement costs, while the cost of requiring zero-bleed pneumatic controllers (such as those driven by compressed air instead of natural gas) at gas processing plants was $1,824 per short ton of VOC. *See* 76 Fed. Reg. at 52,760 – 52,761.

[266] *See* Waste Not, *supra* note 245, at 26 and Technical Appendix 2.

[267] 5 C.C.R. § 1001-9 XVIII (2009), available at https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=2772&fileName=5%20CCR%201001-9.

[268] *Supra* n. (previous note) at § 1001-9 XVIII.C.3 (2009).

[269] Ex. VI-6, Email from Daniel Bon, CDPHE, to David McCabe, Clean Air Task Force, 1 November 2013.

[270] Waste Not, *supra* note 245, at 32.

and storage segment of the industry is very feasible and cost-effective.

Beyond the standards reflected in EPA's proposal, it is also feasible to use zero-bleed devices at facilities with access to grid or renewable energy. Indeed, Colorado requires the use of zero-bleed devices at all new facilities where "on-site electrical grid power is being used" and where such use and "is technically and economically feasible."[271] While Colorado's requirement is limited to sites where grid power is in use, as discussed above, operators also can utilize solar or other non-grid sources of electricity to power pneumatic controllers. Similarly, the Ohio EPA recently released a draft general permit that requires all pneumatic controllers located between the wellhead and the point of custody transfer to an oil pipeline or a natural gas transmission line or storage facility to be no-bleed or non-gas driven.[272]

Furthermore, EPA has not considered the availability of reducing emissions from pneumatic controllers by routing gas that would otherwise be vented from them to a process or a control device. Wyoming requires operators of new and existing pneumatic controllers to either route emissions to a closed loop system or limit emissions to low-bleed levels.[273]

EPA has also failed to address emissions from intermittent-bleed pneumatic controllers in any way. Lastly, EPA has not required operators to ensure that controllers are performing properly, and not excessively emitting.

Because the agency has omitted important sources of emissions for which controls exist, and more effective options for controlling emissions exist for many – if not most – pneumatic controllers, EPA must strengthen the proposed standards. Doing so will address emissions from intermittent-bleed pneumatic controllers and more effectively control emissions from continuous bleed controllers than under EPA's current proposal.

D. EPA Should Consider More Protective Approaches to Reducing Pneumatic Controller Emissions.

EPA's proposed standards fail to account for the availability of either zero-emitting technologies or approaches to reduce emissions by routing emissions from controllers to a process or control device. EPA considered only two control options for pneumatic controllers: "(1) use of a low-bleed controllers; or (2) use of non-gas driven controllers (i.e., instrument air systems)."[274] The proposed standards do not consider the route to process approach in any way, and they only require zero-bleed technology for continuous-bleed pneumatic controllers at natural gas processing plants. Regarding zero-bleed technology outside of gas processing plants, EPA stated in its proposal that

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[271] 5 C.C.R. 1009-Section XVIII.C.2.a.(ii).
[272] Ohio EPA, General Permit 18.1. Template, C.1.(c)(1), *available at* http://epa.ohio.gov/dapc/genpermit/permitsec.aspx.
[273] Wyoming DEQ, *Oil and Gas Production Facilities Chapter 6, Section Permitting Guidance*, at 11, *available at* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf.
[274] 80 Fed. Reg. at 56,623.

> [I]n order to use an instrument air system, a constant reliable electrical supply would be required to run the compressors for the system. At sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices are technically feasible in all situations. Therefore, for the production and transmission and storage segments, where electrical service sufficient to power an instrument air system is likely unavailable, we evaluated only the option to use low-bleed controllers in place of high-bleed controllers.[275]

EPA's conclusion that only low-bleed controllers are appropriate outside of natural gas processing plants disregards numerous zero-bleed technologies which can be feasible at sites other than processing plants, as well as the usefulness and wide applicability of routing emissions from pneumatic controllers to processes on site.

1. <u>Inherently zero-emitting technologies</u>

Instrument air systems and other inherently non-emitting sources, such as electric actuators, could be feasible at many facilities beyond gas processing plants. While sufficient electrical service may not be available at each and every site, many sites do have sufficient access,[276] or may be able to use other approaches to generate power, either for instrument air or for electric actuators. Other sites may be able to use closed-loop gas-driven controllers, a different zero-emissions technology.

- *Grid connection*.[277] At sites that are connected to the electric grid, or with power available nearby, instrument air systems can replace gas-driven pneumatic controllers. As discussed below, for even modest facilities, instrument air will be cost-effective when power is available.

- *On-site generator*. Many sites produce power for on-site use using a natural gas-powered generator. Building out an instrument-air pneumatic system would be feasible in such cases. Beyond a traditional gas-powered generator, innovative technologies can bring electricity to remote sites. For example, thermoelectric generators are available that can be used to convert waste heat in compressor exhaust to electricity at remote oil and gas sites.[278]

- *Solar generator with battery storage*. Natural gas-driven devices can be replaced with electric actuators with low electricity requirements. Such devices are engineered by a variety of companies, and the technology continues to advance. One company has installed over 3,000 electric actuators at oil and gas sites in a variety of applications

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[275] *Id.*
[276] *See* C.C.R., *supra* note 271.
[277] Ex. VI-7, Alphabet Energy presentation at Natural Gas Star Annual Implementation Conference, November 18, 2015. Included here as an exhibit, will soon be posted on Gas Star website. Based on a survey of companies, 34% of companies in the U.S. report that their gathering compressor stations have grid access.
[278] *See, e.g.*, Alphabet Energy, Oil and Gas Products, *available at* https://www.alphabetenergy.com/product_category/oil-and-gas/.

(dump valves, gas lift valves, separators, pressure valves, and compressor scrubbers).[279] In many geographic locations, the solar resource is sufficient to power these actuators.[280]

- *Closed-loop pneumatic actuators.* Some pneumatic controllers use pressurized natural gas to operate but are designed to vent exhaust gas back into the line, as a "closed-loop" option. Assuming that the device does not leak, this is a zero-bleed technology, though it may be limited in applicability.[281]

Electricity availability at sites is increasing while the power required for zero-bleed pneumatic alternatives is decreasing. As a result, many sites, both in the production and transmission and storage segments, will be able to install zero-bleed pneumatic alternatives at low net cost. Thus, EPA should revise its rule to account for the availability of such technologies.

Given the size of many production and transmission facilities, even older technologies, such as compressed air systems, can be cost-effective means of avoiding methane emissions. For example, based on cost figures from EPA's Natural Gas STAR reports and the agency's emissions factors, we estimate that a three well site might typically have eight pneumatic controllers,[282] emitting about 6.2 tons per year of natural gas (using the overall average emission factors from Allen et al. (2015)). If power is available at the site, either from the grid or one of the on-site generation methods described above, an instrument air system to drive the pneumatic controllers could eliminate the methane pollution at a net abatement cost of $1,100 per short ton of methane[283] (assuming the single-pollutant method that EPA uses to examine costs in its proposal).[284] Since this approach would also abate VOC pollution from pneumatic controllers, we also calculated the abatement cost for VOC. Using the single pollutant method, the VOC abatement cost is $3,955 per short ton of VOC.[285] The multi-pollutant method[286] results in event lower net costs: $550 per short ton of methane abatement and $1,978 per short ton of VOC abatement.[287]

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[279] *See, e.g.*, Ex. VI-8. Exlar presentation at Natural Gas Star Annual Implementation Conference, November 18, 2015. Included here as an exhibit, will soon be posted on Gas Star website. Exlar. *Industries and Applications: Oil and Gas Industry, available at* http://exlar.com/industry/oil-gas-applications/, http://exlar.com/pdf/?pdf=/content/uploads/2014/10/Exlar-Eliminates-Methane-Emmissions.pdf

[280] *See, e.g.*, Ex. VI-8. Slide 16.

[281] TSD at 131. Note that API, in their comments on EPA's White Paper on Pneumatic Controllers, corrected EPA's statement in the White Paper that closed-loop controllers are only applicable "in applications with very low pressure." API stated, "Zero bleed controllers (integral controllers) are not limited to applications 'with very low pressure' and can operate over a wide range of pressures provided that the pressure downstream of the controller is sufficiently lower than the pressure upstream of the controller for the controller to function and allow upstream gas to discharge into the process flow downstream…They are common in high pressure applications." Ex. VI-9, API, "API Comments on Oil & Natural Gas Sector Pneumatic Devices," June 14, 2014, at 9.

[282] Allen, *et al*. (2015), *supra* note 246, at 633, report that wellsites have about 2.7 pneumatic controllers per well.

[283] *See* Ex. VI-10, CATF cost analysis for well pad with 3 wells and 8 pneumatics, based on Natural Gas STAR documentation.

[284] 80 Fed. Reg. at 56,617.

[285] *Id.*

[286] 80 Fed. Reg. at 56,617.

[287] *See* Ex. VI-10.

2. Route to process.

Emissions from pneumatic controllers can, alternatively, be controlled by routing the emissions to a process, such as an on-site VRU or fuel lines for an on-site engine, boiler, or heater. A second option, inferior to routing to a process but certainly preferable to uncontrolled venting, is routing the emissions to a control device. While capturing gas that would otherwise be vented and routing it to a process is always preferable to flaring and must be prioritized under any proposed standard, routing to a completion combustion device should be permitted where venting would be an operator's only other option.

The general approach of routing to a process or control is similar to the one EPA has taken in its proposed standards for pneumatic pumps that are not at gas processing plants (proposed § 60.5393a(b)), although as noted below, EPA should strengthen those proposed standards. Wyoming's recent rules for existing pneumatic controllers in the Upper Green River Basin allow operators of existing high-bleed controllers to route emissions "into a sales line, collection line, fuel supply line, or other closed loop system."[288] Some operators have chosen to route emissions from pneumatic controllers to fuel lines in Wyoming.[289] Additionally, the California Air Resources Board (CARB) released Draft Regulatory Language in April 2015, which prohibits venting from *any* continuous-bleed pneumatic controller. To control emissions from these devices, CARB included as a compliance option: "Collect the vented natural gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device."[290] This approach would work for all types of pneumatic controllers.

Furthermore, as with pneumatic pumps, this approach would be cost-effective. EPA estimates that the capital and installation cost of routing emissions from a pneumatic pump to an existing VRU is $2,000; the annualized cost is $285.[291] These cost estimates are equally applicable to the costs of routing emissions from a pneumatic controller to process or control. A single intermittent bleed controller, emitting at the average rate for pneumatic controllers as estimated by the Reporting Program (13.5 scfh), vents 118 Mcf of natural gas per year, which, at $4 per Mcf, has a resale value of $473. Therefore, routing emissions from intermittent-bleed controllers to a VRU would have a negative cost. If intermittent-bleed controllers are emitting at the rates reported in Allen *et al*. (2013), 17.4 scfh, then the cost savings from this approach would be even more striking. Finally, we consider the emissions estimates from Allen *et al*. (2015), which reported that oil and gas pneumatic controllers emit an average of 5.5 scfh, but also found that

[288] 020-020-008 Wyo. Code R. § 6(d).
[289] *See* Ex. VI-11. This approach is described in the Permit Analysis for QEP Energy Company's Mesa 3-22 PAD (AP-12533) and Mesa 7-8 PAD (AP-15216). These examples were found in a review of a small number (23) of Wyoming oil and gas production facility air permits. Because of the small number of permits that were reviewed, we are unable to estimate how widespread this approach is in Wyoming.
[290] *See* California Air Resources Board (CARB) Proposed Regulation Order, Article 3: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (hereinafter, CARB Proposed Standards for Oil and Gas), at § 95213(g)(1), *available at* http://www.arb.ca.gov/cc/oil-gas/meetings/Draft_Regulatory_Language_4-22-15.pdf
[291] USEPA, "Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities: Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa," August 2015 at 164.

sites have an average of 2.7 pneumatic controllers per well. Even for a single well site with just two controllers—below the average of 2.7— if each device emitted 5.5 scfh, they would total 96 Mcf per year, with resale a value of $384. The cost of routing two controllers to a VRU would only be slightly higher than the cost of routing a single controller to the unit on a small site such as a single well pad, so even with the lower emissions factors reported by Allen *et al*. (2015), the increased revenue from capturing gas from pneumatic controllers would exceed the cost of control.

E. EPA Should Strengthen Standards to Address Intermittent-Bleed Controllers.

EPA has declined in the proposed rule to adopt standards for intermittent-bleed controllers, stating that "[i]ntermittent controllers are inherently low emitting sources because they vent only when actuating and the total emissions are dependent on the applications in which they are used."[292] This argument is problematic in several ways. First, EPA's own emission factor (from the Reporting Program) for intermittent-bleed pneumatic controllers, 13.5 scfh per controller, would result in about 1.9 metric tons of methane per year, per device, while also emitting other pollutants. As described above, Allen *et al*. (2013) report that emissions from intermittent-bleed pneumatic controllers are still higher, by 29 percent. Based solely on these emissions factors, EPA's statement that intermittent-bleed controllers are "low emitting" is not supported by the scientific evidence.

Moreover, as discussed above in Section XX, intermittent-bleed controllers often improperly function and emit continuously, contradicting EPA's statement that these devices only vent when actuating. For example, Allen *et al*. (2015) provide time traces of the emissions from the 40 highest-emitting pneumatic controllers that they measured. These 40 controllers represented only 11 percent of the controllers measured in the study but accounted for 81 percent of the emissions. At least 11 of these 40 controllers were intermittent-bleed devices that were improperly functioning.[293] For example, one controller (i.d. number CZ10-PC01) only actuated twice during a 30-minute measurement period, but emitted (over the entire period) at an average rate of 43.2 scfh of whole gas.[294] Given the fact that emissions from individual, supposedly intermittent controllers are significant, as well as the very large number of such controllers in use, their emissions are of great concern. As shown above in Table 11, according to the Reporting Program, 85 percent of reported methane emissions from production pneumatic controllers – amounting to 849,096 tons of methane per year – originates from intermittent-bleed controllers.

EPA must address these emissions. The approaches described above – use of zero-emitting technologies and route to process or control – are just as feasible as a means of capturing emissions from intermittent-bleed controllers as they are from continuous-bleed controllers.

F. Suggested Approach

[292] 80 Fed. Reg. at 56,622.
[293] *See* Allen *et al*. (2015), *supra* note 246, at Supporting Information, section S-8. Controllers LB05-PC03, LB05-PC01, LB07-PC02, LB03-PC01, CZ10-PC01, XQ01-PC04, GZ04-PC03, LB07-PC04, AP01-PC12, CZ11-PC01, and CZ08-PC02 all show actuations and were assessed as improperly functioning (i.e., "equipment issues").
[294] *See id.* at Supporting Information, 94.

We urge EPA to strengthen the standards for pneumatic controllers in several respects. First, EPA should require zero-bleed controllers at facilities where electricity is available (from the grid or generated on site). Electricity is generally available at large compressor stations, large production facilities, and sites of all sizes in urbanized areas. Alternatively, operators should route emissions to a process instead of installing zero-bleed technologies. The standards should require operators of sites without access to electricity to route emissions from pneumatic controllers to a process such as to a VRU or fuel line, if available on site. If routing to a process is not available at a site, operators should route emissions to a control device, though this approach is less protective than standards based on zero-bleed devices, and routing to a process should always be the preferred method of control.

For specific cases where pneumatic controllers are required at sites where neither zero-bleed technology nor route to process approaches are feasible, EPA must set standards for all pneumatic controllers (continuous-bleed and intermittent-bleed) that minimize *actual* emissions. It can do so via two improvements. First, EPA should require controllers of both types to emit below six scfh. EPA's proposed standard already would require a lower design bleed rate for continuous-bleed controllers. Properly designed and well-functioning intermittent-bleed controllers can emit below 6 scfh in many applications.[295] Indeed, Wyoming requires that *all* pneumatic controllers emit below 6 scfh, regardless of whether they are continuous-bleed or intermittent-bleed, at new and modified facilities.[296]

In addition, since pneumatic controllers often improperly function and emit more than designed as discussed above in Section XX, EPA must ensure that any controllers venting natural gas continue to operate as designed over their service lifetime. As a first measure, all intermittent bleed gas-driven controllers must be inspected as part of frequent and comprehensive leak detection and repair (LDAR) surveys to ensure that they are not continuously emitting, as we have discussed above in Section III.A.XX. EPA must ensure that newly installed pneumatic controllers that vent at facilities not subject to those provisions (i.e., existing sites) are also inspected to ensure that they do not function improperly and emit excessively.

Furthermore, while gas-driven pneumatic controllers necessarily emit some gas even when functioning properly, controllers of all types frequently emit in excess of the amount they are designed to emit. EPA must ensure that emissions from controllers are regularly measured to ensure that they are not venting excessively. Such volumetric flow measurements can be done at low cost. CARB's draft regulatory language would require that operators of certain reciprocating compressors measure volumetric flow from cylinder rod packing.[297] Measuring the volumetric or mass flow rate from a pneumatic controller with methods such as a high volume sampler,

[295] In their comments on EPA's 2012 oil and gas rules, the American Petroleum Institute stated, "Achieving a bleed rate of < 6 SCF/hr with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller." In fact, API advocated intermittent-bleed devices to achieve the 6 scfh bleed rate, rather than continuous low-bleed devices. *See* API, "Technical Review of Pneumatic Controllers," at 7 (Oct. 10, 2011), available at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0557-0006

[296] WDEQ, *supra* note 273, at 11. This requirement is applied to intermittent-bleed controllers in addition to continuous-bleed controllers. *See* Ex. VI-12, Email from Mark Smith, WDEQ, to David McCabe, 22 September 2014.

[297] *See* CARB, *supra* note 290, at § 95213(e)(3).

bagging, or calibrated flow measuring instruments gives a real value for emissions, while hydrocarbon concentration (which would be measured while carrying out Method 21) is only weakly correlated with emissions.[298] Some leak-detection service providers routinely measure emissions from leaks with high volume samplers,[299] indicating that the cost of these measurements is quite reasonable. EPA should require operators to regularly measure the volumetric flow of emissions from controllers that vent natural gas to the atmosphere as part of their demonstration of continuous compliance with EPA's standards of performance for those devices. Since the proposed regulation would apply only to new and modified controllers, operators could readily facilitate such measurements by, for example by routinely installing pneumatic controllers with hardware attached to simplify attachment of flow meters.

We recognize that certain intermittent-bleed pneumatic controllers should actuate only very rarely. For example, Allen *et al*. (2015) observed that controllers for emergency shut-off devices made up 12 percent of the population of the controllers in that study. It may be reasonable to exclude some intermittent-bleed devices from control requirements for vented gas, if operators can demonstrate that actuation is very uncommon. (If facilities have instrument air installed, however, the costs of connecting that air supply to every intermittent-bleed controller are very low, so that should be required.) Yet even very rarely actuating controllers should still be subject to monitoring during leak detection inspections to ensure that the devices are not emitting even when they are not actuating.

While specific treatment of intermittent-bleed actuators that very rarely actuate may be warranted, the fact that some controllers very rarely actuate cannot be used to justify inaction for the entire class of intermittent-bleed controllers. In addition to the fact that intermittent-bleed controllers frequently function improperly, as discussed above, some actuate very frequently. Of the 377 controllers studied by Allen *et al*. (2015), 24 were intermittent-bleed controllers that actuated at least 10 times during the sampling period, which was typically 15 minutes. Four actuated over 50 times while sampled. These controllers can emit at high levels – five of the 40 highest emitting controllers studied by Allen *et al*. (2015) are intermittent-bleed controllers that were assessed to be operating properly. Since there are available approaches to avoid these emissions, EPA must issue appropriate standards to address this type of pneumatic controller.

VII. Compressors

A. EPA's Proposed Standards for Centrifugal Compressors

Centrifugal compressors operate by directing gas through a series of rotating blades or impellers, which increase the gas pressure. To reduce the quantity of gas leaking through spaces between the device's moving components, each compressor is equipped with either "dry" or "wet" seal systems. Whereas dry seals allow for very little emissions, wet seals utilize a thin layer of oil to form a seal. This oil absorbs pressurized natural gas and must be de-gassed before it is recirculated to the shaft seal. In the absence of controls, the natural gas released during de-gassing is vented to the atmosphere.

[298] Clearstone Engineering *et al.* (2006) at 3.
[299] Carbon Limits (2014) at 10.

EPA's proposed standards for centrifugal compressor affected facilities require operators to "reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater." Proposed 40 C.F.R. § 60.5380a(a)(1). Operators must then either route the recovered gas through a closed vent system to a control device, or route the closed vent system to a process and return the gas to the pipeline or use it onsite for a beneficial purpose. *Id.* § 60.5380a(a)(2). Alternatively, operators may forgo wet-seal compressors and instead choose to install dry-seal compressors, which are not regulated under the proposed standards.

These basic requirements represent a positive starting point, but EPA must go further to ensure that the standards reflect BSER. In particular, EPA should structure its regulations to ensure that captured gas is burned off in a control device as seldom as possible. The regulations should ensure that the captured gas is utilized, either by directing the captured gas back into the pipeline system or by routing it to use as fuel on site, as frequently as possible. In general, gas from wet seal degassing can readily be directed to compressor suction, and at many sites there will be other ways to utilize this gas, such as directing it to a VRU or using it as a portion of the fuel gas for equipment on site. For the infrequent cases where operators conclude that none of these options is workable, the burden must be on the operator to demonstrate this infeasibility. Given the rarity of wet-seals in newly installed centrifugal compressors, requiring operators to demonstrate the need to use a control device rather than utilizing gas from a wet-seal degasser would not impose additional burden. Below, we provide a number of recommendations that EPA should take to embody this principle and improve the efficacy of the standards.

First, we agree that systems to capture gas from wet seal degassing, if properly designed, can be effective tools for reducing methane emissions from centrifugal compressors. EPA has published literature through its Natural Gas STAR program describing how degassing systems equipped with the proper technology—seal oil/gas separators, demisters/filters for both high and low-quality gas, and necessary piping and instrumentation—are cost effective and can largely eliminate vented gas from wet seal compressors.[300] EPA literature presents four different options for using gas that is captured through these devices: 1) return it to compressor suction; 2) route high-pressure gas to a combustion turbine for electricity generation; 3) route low-pressure gas to a heater or boiler to use as fuel; and 4) send the captured gas to a control device.[301] EPA notes that at least one operator has configured its system to use all four of these options.[302] Based on experience from about one hundred installations, BP has reported that systems that return seal gas to compressor suction (the first option) are "simple, broadly flexible, and reliable," and

[300] *See* EPA, *Wet Seal Degassing Recovery System for Centrifugal Compressors* (2014), *available at* http://www3.epa.gov/gasstar/documents/CaptureMethanefromCentrifugalCompressionSealOilDegassing.pdf; *see also* Reid Smith, BP, and Kevin Ritz, BGE, *Centrifugal Compressor Wet Seals Seal Oil De-gassing & Control*, presentation delivered at 2014 Natural Gas STAR Annual Implementation Workshop (May 2014), *available at* http://www3.epa.gov/gasstar/documents/workshops/2014_AIW/Experiences_Wet_Seal.pdf, at 7—19.
[301] EPA, *supra* note 300, at 3.
[302] *Id.*

generate “positive cash flow in less than a month.”[303] In addition, both California and Ohio have proposed requirements for centrifugal compressors that require either the capture of wet-seal emissions or the use of dry-seals. Specifically, the California’s Air Resources Board (ARB) proposes to require operators either use dry seal systems or collect the wet seal vent gas with a vapor collection system.[304] The Ohio EPA similarly proposes operators design wet or dry shaft seals on centrifugal compressors to ensure that no gas is vented from the unit. To accomplish this operators must capture 100% of the gas from the wet or dry shaft seals and route it to a pipeline, fuel gas system, or flare capable of a 98% destruction efficiency.[305]

From both an environmental and economic standpoint, the fourth option is decidedly inferior to the other three, since it generates emissions without providing a beneficial purpose. Yet in the proposed regulatory language, EPA assumes as an initial matter that operators will route gas captured through a wet seal degassing system to a control device, describing routing to a process as an “alternative.” Proposed 40 C.F.R. § 60.5380a(a)(2). The agency has provided no justification for this implied prioritization of combustion over conservation, and we are aware of none.[306] Instead, the final rule should require operators to select one of the first three uses for captured fuel described above, which should be readily available options in nearly all instances. EPA should allow for the use of a control device only if the operator can demonstrate that the other three options cannot be employed at a specific installation.

B. EPA’s Proposed Standards for Reciprocating Compressors

Reciprocating compressors are used throughout all segments of the industry. These units are equipped with one or (usually) more rod and piston systems that pressurize natural gas through positive displacement. Each rod in a reciprocating compressor is equipped with a series of seals known as rod packing systems that are designed to minimize the leakage of gas from the compressor’s moving parts. However, rod packing does not entirely eliminate leaks, and the seal becomes less effective over time with normal wear and tear. According to the GHGI and the reports it is based on, rod packing emissions from reciprocating compressors represent 10.6 percent of methane emissions at gas processing plants and 10.2 percent at transmission and storage compressor stations.[307] Another study, conducted by Carbon Limits on behalf of Clean

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[303] *Id.*

[304] CARB, Proposed Regulation Order, Article 3, Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, § 95213(f), (April 22, 2015), available at http://www.arb.ca.gov/cc/oil-gas/meetings/Draft_Regulatory_Language_4-22-15.pdf.

[305] Ohio EPA, General Permit 17.1 Template, C.(1)(b)(1)(d), available at at http://epa.ohio.gov/dapc/genpermit/permitsec.aspx.

[306] In fact, in the Proposed Rule preamble with respect to the new REC standards for oil wells, EPA finds capture of the gas through REC to be preferable to combustion on the following basis: “we determined that combustion alone would not represent the BSER for well completions because, although the emissions reduction would be equal to the REC and completion combustion device combination (i.e., 95 percent control), the opportunity to realize gas recovery would be minimized and the generation of secondary combustionrelated emissions would be increased.” 80 Fed. Reg. at 56,629.

[307] EPA, U.S. GHG Inventory (2015), Annex 3, Tables A-136 and A-137, *available at* http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Compressor seal emissions separated from non-seal fugitive emissions based on EPA/GRI Vol 8 Tables 4-14, 4,17, & 4-24.

Air Task Force, found higher figures still, with rod packing emissions representing 21.2 percent of methane emissions at gas processing plants and 17.0 percent at transmission and storage compressor stations.[308]

EPA has proposed methane and VOC standards of performance for reciprocating compressor affected facilities that grant operators a choice of one of three options: 1) replace compressor rod packing after each increment of 26,000 operating hours; 2) replace rod packing every 36 calendar months; or 3) capture emissions using a rod packing emissions collection system that operates under negative pressure and route the captured gas to a process through a closed vent system. Proposed 40 C.F.R. § 60.5385a(a)(1)-(3). Again, while EPA has identified effective methods for reducing reciprocating compressor emissions—periodic rod packing replacements and the use of rod packing emissions collection systems—we propose several structural and substantive changes to these standards to ensure they reflect BSER.

First, the agency should prioritize the use of rod packing emissions collection systems over periodic rod packing replacements, but require both if feasible. Even newly installed rod packing typically leaks some gas, and these leaks increase as the packing wear down over time. Under EPA's proposed standards, operators opting to replace rod packing every 26,000 hours / 3 years will typically vent this gas to the atmosphere. Replacing an old set of rod packing with a new set certainly reduces the increased emissions that occur as a result of wear and tear, but even the new packing will allow some emissions, and the aggregated sum of emissions over the course of the lifetime of the packing can be significant. A compressor rod packing system with new and well-functioning packing emits approximately 11-12 scfh.[309] This translates to nearly 2 tons of methane per year per compressor cylinder. On the other hand, a collection system can eliminate nearly all of the emissions associated with rod packing in reciprocating compressors. For example, REM Technology's SlipStream® system integrates additional equipment into compressors that captures gas that would otherwise have been vented from rod packing and routes that gas back to the compressor's engine for use as combustible fuel.[310] Field test results indicate that SlipStream technology can reduce methane emissions from compressor rod packing

[308] Carbon Limits, *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras*, CL-13-27 (Mar. 2014), *available at* http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf, at 11, Fig. 5. Note that the figures in the Carbon Limits report do not account for all sources of emission that are included in the GHGI data, such as methane in compressor exhaust and blowdowns.

[309] EPA*, Lessons Learned from Natural Gas STAR Partners: Reducing Methane Emissions From Compressor Rod Packing Systems* (October 2006), *available at* http://www3.epa.gov/gasstar/documents/ll_rodpack.pdf, at 1.

[310] *See Method and apparatus for capturing and controlling fugitive gases*, U.S. Patent No. 8978627, assigned to Rem Technology, Inc., issued Mar. 17, 2015, *available at* http://patents.justia.com/patent/8978627; *Method and apparatus for utilising fugitive gases as a supplementary fuel source*, US Patent No. 8382469 B2, assigned to Rem Technology, Inc. issued Feb. 26, 2013, available at http://patents.justia.com/patent/8382469; *see also* Jimmy Oxford, Targa Resources, and Veronica Nasser, REM Technology, *Reducing Methane and VOC Emissions*, presentation for the 2012 Natural Gas STAR Annual Implementation Workshop (2012), *available at* http://www3.epa.gov/gasstar/documents/workshops/2012-annual-conf/nasser.pdf, at 8—19.

by 95 percent and VOC and HAP emissions by 99 percent.[311] The use of this or similar technologies will result in methane emissions that are consistently well below the 2 tons of methane per year associated with a "well functioning" rod packing system, let alone the emissions from a rod packing system as it approaches the latter part of the three-year period EPA's proposal would allow operators between packing replacements.[312] And, at most sites, as discussed above for centrifugal compressors, there will be other options to utilize this gas, such as directing it to a VRU or using it as a portion of the fuel gas for equipment (such as heaters and re-boilers) on site.

Importantly, both California and Ohio are considering requirements that prioritize rod packing emissions collection systems over periodic rod packing replacements. ARB's draft proposal gives operators the choice of either capturing emissions from each compressor via a vapor collection system, or regularly monitoring and repairing or removing from service compressors with excessive rod packing emissions.[313] The Ohio EPA similarly recently released a draft general permit that requires operators capture 100% of gaseous emissions from reciprocating compressor rod packing seals and control such emissions by routing emissions to a pipeline, fuel gas system or a flare designed for 98% destruction.[314]

Notably, section 111 of the Clean Air Act requires EPA to take into account and spur technological innovation in developing performance standards. See, e.g., *Sierra Club v. Costle*, 657 F.2d 298, 346 n.174 (D.C. Cir. 1981) ("[S]ection 111 was intended 'to assure the use of available technology and to stimulate the development of new technology.'" (quoting S. Rep. No. 95-127, at 114 (1977)). By prioritizing the use of available technology such as SlipStream and other vapor recovery methods, EPA will fulfill this statutory mandate under section 111. EPA should therefore include regulatory text in the final rule specifying that operators should, as a required first option, use an emissions collection system to capture gas from reciprocating compressor rod packing and direct it to a process.

While it should generally be feasible to route the gas from most reciprocating compressors to a process, as described above, if a source operator cannot install an emissions collection system or vapor recovery unit for a specific reason, we agree that periodic rod packing replacements are an important secondary approach to prevent wasteful and environmentally damaging emissions.

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[311] Malm, Howard, REM Technology, et al., *Profitable Use of Vented Emissions in Oil & Gas Production*, presentation delivered at Methane Expo 2013, Mar. 12—15, 2013, *available at* https://www.globalmethane.org/expo-docs/canada13/og_09_malm_1.pdf, at 6 and generally.

[312] For example, Carbon Limits reports on the quantity of methane emitting by rod packing from over 2,000 reciprocating compressor cylinders. Their data show that a high emitting (95th percentile) compressor emits about 125 scfh of methane, or 19 short tons per year per compressor in the production segment. *See* Carbon Limits, *supra* note 308, at 25, Fig. 14. Based on analysis of emissions data by Carbon Limits. The figure differs from Figure 14 in the Carbon Limits report, which combines measurements from single cylinders with measurements of emissions from multiple cylinders manifolded together.

[313] CARB, Proposed Regulation Order, Article 3, Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, § 95213(d)(1), (e)(1) (April 22, 2015, available at http://www.arb.ca.gov/cc/oil-gas/meetings/Draft_Regulatory_Language_4-22-15.pdf.

[314] Ohio EPA, General Permit 17.1 Template, C.(1)(b)(1)(d), available at at http://epa.ohio.gov/dapc/genpermit/permitsec.aspx.

However, EPA's current proposal would require rod packing replacements after certain fixed periods of time (every 26,000 operating hours or every 36 calendar months). The problem with this approach is that rod packing emissions can often grow quite high before the compressor has been operated for 26,000 hours. Indeed, it will often be cost-effective, or even profitable for operators, to reduce emissions by replacing rod-packing before this fixed operation interval has passed. Rather than establish a replacement schedule based on fixed temporal increments, EPA should require operators of reciprocal compressors to measure their emissions and replace their rod packing systems whenever those emissions exceed specific limits.

ARB's draft regulations for oil and gas sector methane emissions are instructive. As noted above, per the proposal operators may either capture emissions from each compressor via a vapor collection system, or regularly monitor and repair or remove from service compressors with excessive rod packing emissions. For larger compressors, direct measurement of the volumetric emission rate is required. ARB's proposal requires replacement or repair of rod packing seals whenever emissions exceed certain specified thresholds.[315] This approach helps to ensure that it is the quantity of emissions, not the increment of time that has passed, that determines when an operator must take action. It not only offers a more effective method for reducing emissions, but also one that will generate more granular emissions data that will assist EPA in future decision-making.

An emissions-based (rather than purely temporal) approach to rod packing replacement would require EPA to establish the threshold at which rod packing replacements are required. In its Natural Gas STAR literature, EPA provides operators with a method for determining a threshold above which replacing rod packing would be more cost-effective than sacrificing the emissions from worn-out packing. The agency notes that,

> A new packing system, properly aligned and fitted, may lose approximately 11 to 12 standard cubic feet per hour (scfh) . . . Under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 scfh.[316]

Second, EPA provides a formula to determine the emissions threshold above which rod packing replacements become profitable for operators:[317]

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[315] The proposal would require quarterly inspections for compressors at or below 500 rated horsepower. For these compressors, the concentration of methane in the air at the point where natural gas from rod packing is vented would be measured. Larger compressors would be subject to annual inspections, with direct measurement of volumetric emissions. Many of the Joint Environmental Commenters provided feedback to ARB commending their general approach to reciprocal compressor emissions, but urging the Board to require quarterly direct measurement of volumetric emissions for *all* compressors, regardless of size. Sierra Club, et al., *Comments to California Air Resources Board on Proposed Oil and Gas Methane Regulations* (May 15, 2015), *available at* http://www.arb.ca.gov/cc/oil-gas/meetings/SierraClub_et_al_5-15-15.pdf, at 11-12.

[316] EPA*, supra* note 309*,* at 1.

[317] *Id.* at 4. We note that an emissions threshold set for rod packing replacement to be *profitable* would fall far short of section 111(b)'s requirements, which mandate that EPA based its designation of the best system of emission reduction based on environmental benefits, with consideration to other factors such as costs and energy requirements. Nothing in the statute requires that a control measure be profitable for

$$\text{Economic Replacement Threshold (scfh)} = \frac{CR * DF * 1{,}000}{H * GP}$$

Where:

CR = Cost of replacement ($)
DF = Discount factor (%)
H = Hours of compressor operation per year
GP = Gas price ($/Mcf)

The discount factor, in turn, is defined as:[318]

$$DF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where i equals the discount rate expressed as a decimal and n equals the payback period selected. In 2006, EPA reported the costs of replacing a rod packing system as $1,620 per cylinder; adjusted to 2015 dollars,[319] that figure is $2,049 per cylinder. EPA also suggests 8,000 hours of annual operation time in its Natural Gas STAR report.[320]

The calculation for economic replacement threshold can be adapted to calculate the net cost, including the savings from capturing gas that would otherwise be vented, of a standard that would require the replacement of rod packing when emissions from a cylinder reach a certain threshold. EPA must design its emissions threshold for rod packing replacements with the environmental benefits as the foremost consideration. As the threshold increases, both environmental benefits and economic costs decrease. Using standard values in addition to those mentioned above,[321] Table 12 shows net abatement costs associated with several replacement thresholds that we considered. Based on these results, and compared to the abatement cost for EPA's entire proposal of $980 per short ton,[322] we conclude that a standard which requires replacement of rod packing when emissions from a cylinder reach 20 to 25 scfh would be reasonable.

Table 12: Abatement Costs Associated with Rod Packing Replacement Thresholds

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companies to qualify as BSER; quite the contrary, courts have acknowledged that EPA must design its section 111 regulations to achieve "the greatest degree practicable," *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 434 n. 14 (D.C. Cir. 1973), rather than the most financially optimal for operators. *See* Section II.A*, supra; see also Pacific Power Co. v. EPA*, 647 F.2d 60, 68 (9th Cir. 1981) (holding that Congress intended that new source emissions controlled under section 111 would be reduced "to a minimum").

[318] *Id.*

[319] *Id* at 5. Converted to 2015 dollars following methodology described in Gas Star Document using Nelson Price Indexes.

[320] *Id.*

[321] These standard values are 1.1023 short tons per metric ton, .0212 short tons per Mcf, 79 percent methane content of raw natural gas, and a payback period of 1.5 years (assuming more frequent replacements of rod packing than in the previous example).

[322] OOOOa RIA table 3-6.

Replacement Threshold (scfh)	Net Abatement Cost ($/short ton)
15	$1,716
20	$538
25	$232
30	$92

For context on the suggested replacement threshold between 20 and 25 scfh per rod packing, consider the distribution of emissions reported by Carbon Limits, based on a database comprised of records from direct measurements of 2,361 compressor cylinders. Carbon Limits report that approximately 72 percent of rod packings in the field at any given time emit between 0 and 20 scfh, about 12 percent emit between 20 and 40 scfh, and 15 percent emit greater than 40 scfh.[323]

C. EPA Must Propose Standards for Well-Pad Compressors

EPA has expressly exempted both centrifugal and reciprocating compressors at well-sites from the proposed standards. The agency exempted well-site centrifugal compressors under the assertion that "our data indicate that there are no centrifugal compressors in use at well sites." 80 Fed. Reg. at 56,618. In fact, EPA's own Reporting Program data reveal 69 wet-seal centrifugal compressors in the Onshore Petroleum and Natural Gas Production segment in 2014, including 43 that were reported in 2014 but not in 2013.[324] The only type of Onshore Petroleum and Natural Gas Production facilities that reported emissions to the Reporting Program for 2014 or previous years are well facilities,[325] so these are centrifugal compressors located at wellpads. In 2014, methane emissions from wet-seal centrifugal compressors at these sites totaled 16,000 metric tons, according to EPA's Reporting Program data.[326] The agency's bare assertion that there are "no" such compressors is plainly contradicted by its own information.[327] The agency must therefore cover these sources under its final rule.

[323] Carbon Limits, *supra* note 308, at 25, Fig. 14. Based on analysis of emissions data by Carbon Limits. The figure differs from Figure 14 in the Carbon Limits report, which combines measurements from single cylinders with measurements of emissions from multiple cylinders manifolded together.
[324] EPA, Greenhouse Gas Reporting Program (GHGRP)-- Petroleum and Natural Gas Systems. W_CENTRIFUGAL_CMPS_ONSHORE, *available at* http://oaspub.epa.gov/enviro/ad_hoc_table_column_select_v2.retrieval_list.
[325] *See* description of "Onshore petroleum and natural gas production" for Subpart W of the GHGRP at 40 C.F.R. §98.230(a)(2). Note that while Subpart W will be amended, effective January 1, 2016, to include a new industry segment, "Onshore petroleum and natural gas gathering and boosting," the "production" segment will continue to only include wellpads.
[326] EPA, *supra* note 324. Note: This is potentially an underestimate of total centrifugal compressors in the production segment; it does not capture compressors at facilities that fall below the Reporting Program's threshold of 25,000 metric tons CO_2e.
[327] Even if there were few or no such units currently planned in the future, that is no justification to exempt them from the regulations. For example, EPA recently finalized carbon pollution standards for new fossil fuel-fired electric generating units—including new coal plants—even though the agency "predict[ed] that very few, if any, new coal-fired steam generating EGUs will be built in the near term." 80 Fed. Reg. 64,510, 64,558 (Oct. 23, 2015). EPA would therefore have no basis to exclude centrifugal compressors at well-pads on the basis that there are not projected to be many constructed in future years, and even less basis in light of the fact that new units are, in fact, coming online.

There are also thousands of well-site reciprocating compressors across the nation, and they pose a significant source of emissions unless properly controlled. For example, an oil and gas emission inventory determined that there are 0.192 compressors per well site in the Eagle Ford shale formation, 0.40 per well site in the Fort Worth area, and 0.45 compressors per well site in the Western Gulf Basin.[328] Once at a well site, these compressors operate nearly 24 hours per day.[329]

However, in the proposed rule, the agency claims that it concluded in the 2012 VOC rule that the cost-effectiveness threshold for regulating well-site reciprocating compressors was too high at $2,457 annually, or $15,802 per ton, and that its findings have not changed since then.[330] For this reason, EPA concluded in the Proposed Rule that the costs of rod-packing replacement at well-site compressors were not reasonable.[331]

This cost-effectiveness conclusion is arbitrary and based on outdated information. EPA states in the Proposed Rule that reciprocating compressors at well sites have "emissions of 0.198 tpy methane and 0.055 tpy VOC."[332] The source for this emissions data is provided in EPA's April 2014 white paper, "Oil and Natural Gas Sector Compressors," which states that EPA derived the data from a 1996 joint study by EPA and the Gas Research Institute (GRI).[333] The GRI/EPA study data that EPA used for well-site compressors, however, is actually based on the component emission factor (expressed in MScf/component-yr) for "Compressor Seals" for thirteen "Gathering Compressors" from 1993 and 1995 studies.[334] The reported emissions factor (0.271 scfh per cylinder) is extremely low. Consider that, as noted above, EPA reports that "Under the best conditions" newly installed rod packing can be expected to emit 11.5 scfh per cylinder.[335] EPA's continued reliance on this outdated gathering compressor emissions information to estimate emissions from well-site compressors is arbitrary in light of the agency's use of a more recent 2006 study to estimate emissions from gathering compressors,[336] while continuing to use the outdated emissions factor, originally based on gathering compressors, for wellpad

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328 *See* Alamo Area Council of Gov'ts, *Oil and Gas Emission Inventory, Eagle Ford Shale, Final Technical Report* 6-2 (Oct. 2015), *available at* http://www.aacog.dst.tx.us/index.aspx?NID=98.
329 *Id.* ("The Barnett Shale Special inventory final results found wellhead compressors ran for an average of 7,702 hours per year, while ENVIRON's Haynesville Shale report and San Juan Public Lands Center's study in Colorado used 8,760 hours.").
330 *See* 80 Fed. Reg. at 56,620-21.
331 *Id.* at 56,621.
332 *Id.* at 56,620.
333 *See* EPA, *Oil and Natural Gas Sector Compressors: Report for Oil and Natural Gas Sector Compressors*
Review Panel 22 Tbl. 3-10, 23 Tbl. 3-11. (2014) [hereafter Compressor White Paper].
334 *See* GRI/EPA, *Methane Emissions from the Natural Gas Industry, Volume 8: Leaks* 39 Tbl. 4-8 (1996), *available at* http://www3.epa.gov/gasstar/documents/emissions_report/8_equipmentleaks.pdf. In turn, the GRI/EPA data is based on a 1993 study and a 1995 study by Star Environmental. *Id.* at 82 (references 8 and 9).
335 EPA, *supra* note 309, at 1.
336 *See* Compressor White Paper, *supra*, at 22 Tbl. 3-10 n.b (citing Clearstone Engineering, Ltd., *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites* (2006)).

compressors. Per the 2006 study, EPA estimates gathering compressor emissions are "12.3 tpy methane and 3.42 tpy VOCs,"[337] and based on these estimates EPA determines the cost of regulating gathering compressors is reasonable.[338] Note that the updated emissions factor for "gathering and boosting compressors," 12.3 tpy, is about two orders of magnitude higher than the older emission factor for "gathering compressors," 0.198 scfh, which EPA is arbitrarily using as a proxy for wellpad compressors. Clearly this older emissions factor is not appropriate for wellpad compressors.

EPA should have relied on updated emission factors to estimate emissions from well-site compressors as it did to estimate emissions from gathering sector compressors, or at least explained why it failed to rely on updated emissions data to estimate emissions from well-site compressors. If it does the latter, EPA must obtain proper, current data on emissions from well-site compressors and move to regulate these sources as soon as possible.

VIII. Storage Vessels

Storage vessels are significant sources of methane emissions, estimated at 533,930[339] tons per year according to the GHGI and with 94,666[340] tons reported under the GHGRP. Moreover, as with many other sources in the oil and gas industry, there is reason to believe that storage vessels account for significantly more methane pollution than currently estimated.[341] EPA has addressed storage vessel air pollution to some extent in the 2012 VOC NSPS and NESHAPs and amendments to those standards, and has begun another process under section 112 that could lead to additional control of storage vessels, *see* 80 Fed. Reg. 74,068 (November 27, 2015) (Oil and Natural Gas Sector: National Emission Standards for Hazardous Air Pollutants, Request for Information). However, as explained above, such standards do not absolve the agency of its responsibilities to address methane from storage vessels under section 111, and the regulations currently in place leave a number of storage vessels uncontrolled. We urge EPA to address storage vessels in this rulemaking, including whether additional performance standards for methane covering storage vessels are appropriate.

IX. Liquids Unloading

EPA has not proposed standards applicable to liquids unloading activities, but requests comment on possible approaches the agency could take to address these sources, including "technologies and techniques that can be applied to new gas wells that can reduce emissions from liquids unloading in the future." 80 Fed. Reg. at 56,614-615. As EPA recognizes in the proposal, liquids unloading emissions are significant and are dominated by a relatively discrete number of high emitting wells. Moreover, several technologies are capable of reducing (or eliminating) these

[337] 80 Fed. Reg. at 56,620; Compressor White Paper, *supra*, at 22-23.
[338] 80 Fed. Reg. at 56,621.
[339] 2013 GHGI, Annex 3, Tables A-129 and A-149, available at http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG_Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.
[340] U.S. EPA, GHGRP, Petroleum and Natural Gas Systems, W_SOURCE_SUMMARY, available at http://www.epa.gov/enviro/facts/ghg/customized.html.
[341] *See, e.g.*, EPA Compliance Alert 2015.

emissions, including at wells both with and without plunger lift systems. Below, we discuss emissions associated with liquids unloading activities and urge EPA to develop liquids unloading standards based on the available technologies.

A. Emissions From Liquids Unloading Activities Are Significant, and Available Technologies Can Reduce These Emissions.

i. *Liquids Unloading Emissions are Significant*

Wells accumulate liquids when the reservoir gas pressure is insufficient for lifting liquids up the wellbore. The liquids settle at the bottom of the well tubing, obstructing gas flow and inhibiting production. Since reservoir pressure declines as wells age, liquids accumulation eventually becomes an issue in most wells, although when and how often wells require liquids unloading varies. Sometimes, operators remove these liquids by venting a well, which reduces the downward pressure on the liquids from pipeline to atmospheric pressure. If the reservoir pressure is higher than the liquid pressure, then some of the liquids will be lifted out of the wellbore, temporarily restoring gas flow. During this process, however, gas will also be vented, which depletes reservoir pressure and therefore exacerbates the problem in the long-term.

As EPA recognizes in the preamble, liquids unloading emissions are significant, and a small minority of wells contribute the majority of the sector's emissions. *Id.* at 56,645. Based on measurements of over 100 wells, Allen, et al. (2014) estimates that 2012 unloading emissions in the United States were 270 Gg methane—the third largest emission source in the natural gas production segment.[342] Several other recent studies suggest nationwide liquids unloading emissions of approximately 300 Gg methane.[343] These emissions are dominated by a small number of high-emitting sites: Allen, et al. found that less than 20 percent of wells (both with and without plunger lifts) accounted for the majority of emissions, and the most recent Reporting Program data suggest that 19 percent of wells are responsible for about 75 percent of the unloading venting emissions.

EPA specifically requests comment on the level of methane and VOC emissions per unloading event, the number of unloading events per year, and the number of wells that perform liquids unloading. EPA's recently released Reporting Program data and the 2014 Allen, et al. study provide key insights in each of these areas, presented in Table X below:

<u>Table X: Liquids Unloading Data Requested by EPA</u>

	2014 Subpart W [1]		**Allen *et al.* (2014)**		
	With	*Without*	*Manual*	*Automatic*	*Without*

[342] Allen (2015), at 641–648.

[343] *See* ICF (2014). ICF's estimate of 321,012 MT methane is derived by scaling up an estimate derived from GHGRP data by 15%, based on EPA's estimate that 85 to 90% of emissions are covered by the GHGRP; *see also* API/ANGA, "Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses," at 14 ("API/ANGA"), available at http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf. The API/ANGA estimate of 319,664 MT methane, which is similar to ICF's estimate, was estimated using engineering equations along with survey data.

	Plunger Lifts	*Plunger Lifts*	*Plunger Lifts*	*Plunger Lifts*	*Plunger Lifts*
Methane Emissions Per Unloading Event	0.0002 – 16.0 Mg/event	0.002 - 118.7 Mg/event	0.004 – 0.94 Mg/event	0.001 – 0.15 Mg/event	0.011 – 2.6 Mg/event
Average Methane Emissions per Unloading Event	0.33 Mg/event (0.06 Mg/event[2])	1.16 Mg/event (0.29 Mg/event[2])	0.186 Mg/event	0.024 Mg/event	0.414 – 0.674 Mg/event [3]
Average Number of Unloading Events Per Year	67 events/well (range from 1 – 3,316 events)	14 events/well (range from 1- 2,008 events)	<100 events/well	1,870 events/well	<50 events/well [4]

[1] Figures only reflect reported data for wells with non-zero well count, events, and emissions values.
[2] Value represents the geometric mean of the reported data.
[3] The low end of the range corresponds to wells with fewer than 10 events per year and the higher end to those with fewer than 50 events per year.
[4] 1.1% of wells without plunger lifts undergo more than 50 events per year.

ii. *Available Technologies Can Reduce These Emissions.*

In response to EPA's Liquids Unloading White Paper,[344] several commenters provided extensive information on technologies available to restore production to wells with liquid unloading issues while eliminating or minimizing emissions.[345] We incorporate those analyses by reference and briefly highlight a few salient aspects of each of these technologies.

Plunger lifts are one technology that can minimize or eliminate venting during liquids unloading by using a well's own reservoir pressure to overcome pressure differentials. However, plunger lifts do not always lead to low emissions. Some wells equipped with these devices have high emissions because plunger lifts are installed to increase gas production and not specifically to reduce emissions. For example, if a plunger lift fails to reach the surface by its own mechanics, then the well may be manually or automatically vented to lift the plunger up. However, an efficiently functioning plunger lift can unload liquids with zero emissions.

Allen, et al. reports a higher average emission factor per event for non-plunger lift- equipped wells than plunger lift wells,[346] though annual emissions can be higher for plunger lift wells due

[344] USEPA, "White Papers on Methane and VOC Emissions: Liquids Unloading," *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/20140415liquids.pdf.
[345] Environmental Defense Fund, "Oil and Natural Gas Sector: Liquids Unloading Processes Peer Review Responses of Environmental Defense Fund June 16, 2014," *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/attachmenti.pdf; Sierra Club et al, "Comments on All Five of EPA's White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector," *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0557-0041.
[346] Allen (2015), at 641.

to higher frequency of venting. A separate study conducted by API/ANGA[347] included an industry survey of over 40,000 wells and concluded that only 21.1 percent of wells equipped with plunger lifts vent to the atmosphere. If the Allen, et al. plunger lift emission factor is adjusted to account for the 78.9 percent of wells that do not vent, then automatic plunger lift and manual plunger lift wells have average annual methane emissions of 518 and 25 Mscf, respectively, compared to 1,011 Mscf from non-plunger lift wells. Therefore, although some wells equipped with plunger lifts are associated with significant emissions, those wells would surely have much higher emissions *without* the lifts.

Furthermore, total automatic plunger lift well emissions are highly influenced by the fact that many wells with automatic plunger lifts vent over 1,000 times per year. In fact, automatic plunger lift wells with high venting frequencies (i.e., those that vent over 100 times per year) are estimated to contribute the majority of all emissions from wells with venting for liquids unloading. BP has demonstrated that optimization of plunger lifts with smarter automation can drastically cut emissions—reducing them from over 4 Bcf/year to less than 0.01 Bcf/year using these practices.[348] Accordingly, well operated plunger lifts are an effective means of reducing (or eliminating) the need for venting from most wells with liquids accumulation issues. EPA should propose liquids unloading standards based on the emission reduction benefits from this technology.
Beyond plunger lifts, other solutions are also available, such as installing velocity tubing or using compressor engines to lower the pressure differential between the reservoir and the wellhead. When the aforementioned technologies are insufficient to lift liquids, creating artificial lift can successfully remove liquids from wells with little or zero emissions. Furthermore, although capture technology must always take priority over wasteful completion combustion, flaring may be an option to reduce emissions from liquids unloading where an operator cannot make use of other technologies and would otherwise have no choice but to vent gas released during the event.

In light of this information, EPA should establish a numeric, performance-based annual venting limit that incorporates the emission reduction potentials of the different technologies that can reduce emissions from liquids unloading events. Individual wells with liquids accumulation issues may respond differently to the various options for unloading those liquids in order to increase production. For instance, some wells may require a single blowdown to restore production, while others may require artificial lift because reservoir pressure is insufficient to effectively utilize a plunger lift. This makes it challenging to apply a single capture technology at all wells to minimize venting due to liquids unloading.

Accordingly, to address liquids unloading emissions consistent with its section 111 obligations, EPA should establish a quantitative emission limit that operators can satisfy with whichever technology works best for them. Moreover, due to the skewed distribution of well emission rates, a large fraction of total emissions can be reduced by setting an emission limit that only affects a relatively small fraction of "super-emitting" wells. The agency should take this fact into account as it develops standards for liquids unloading.

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[347] API/ANGA, at 13.

[348] USEPA, Lessons Learned from Natural Gas STAR Partners, "Options for Removing Accumulated Fluid and Improving Flow in Gas Wells," at 12, *available at* http://www3.epa.gov/gasstar/documents/ll_options.pdf.

iii. *Recommendations for Design of the Standards.*

By adopting certain definitions of "modification" and "affected facility" and establishing an annual venting limit, EPA can promulgate standards for liquids unloading at gas wells that secure substantial reductions at a reasonable cost to industry.

- Modification. As we describe above, many gas wells reach a point in their productive lives at which reservoir pressure is no longer sufficient to flow produced liquids to the surface, causing accumulation of liquids and inhibiting gas production. At this point, operators can take various actions to restore production, all of which constitute changes in the method of operating a well and some of which likewise constitute physical changes (i.e., installing a plunger lift system). To the extent that these changes are accompanied by venting during liquids unloading, EPA should define the regulatory term "modification" to encompass these activities.

- Affected facility. EPA should also define an "affected facility" for the purpose of its section 111 regulations to cover any liquids unloading facility as a well that vents in excess of a certain minimum threshold (for instance, 100 mcf/year). This would ensure the majority of emissions are addressed by the standards, but would focus standards on only the highest emitting wells.

- Emission limit. EPA should establish a numerical emission limit based on a BSER that reflects the emission reduction potentials of the technologies discussed above. The standard could require affected liquids unloading facilities to meet an annual venting limit based on an otpimal mcf/year value, or alternatively, to achieve a certain percentage emission reduction. This standard should prioritize captured-based technologies, like smart automation, to enhance environmental performance and further reduce costs, and flaring should only be considered an option of last resort.

X. Compliance.

As a general matter, state compliance requirements used to demonstrate compliance with the federal standards must be straightforward to ensure public health and environmental benefits. A few leading states have established state substantive requirements that are more stringent than the proposed federal standards. Affected facilities in compliance with these more stringent state requirements may also be in compliance with EPA's proposed standards. EPA solicits comments on how it should determine whether the state compliance demonstrations (*i.e.*, monitoring, record keeping, reporting) also demonstrate compliance with the federal standards.

EPA's determination must be governed by whether the state requirements demonstrate reductions that are at least equivalent to those that will be achieved under the federal rules. The Act is clear that when a person seeks to use an "alternative means" in lieu of the federal work practice standard established under section 111(h)(1), that person must establish that the alternative will "achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant" under the federal standard. 42 U.S.C. § 7411(h)(3).

Many of the work practice standards EPA has proposed allow such a comparison.[349]
For the federal performance standards (*i.e.*, those that have numerical emission limits), EPA's determination should be straightforward. To ensure compliance with the federal rule, a state's requirements must demonstrate that at least the same emission performance is achieved within the state. For example, if the federal performance standard is a 95.0 percent reduction of methane, then the state requirements to demonstrate compliance must show that at least 95.0 percent of methane is reduced from the affected facility.

However, the structure of EPA's proposed leak detection and repair (LDAR) requirements does not readily allow for an evaluation of equivalent reductions. As discussed above, emissions – and thus the achievable reductions – from leaking components are not correlated to the percentage of leaking components. In fact, a single leaking component could be responsible for an enormous amount of pollution. Accordingly, we urge EPA to strengthen LDAR provisions, as we describe more fully above, to be more aligned with state programs that lack these frequency adjustment provisions. Doing so will secure critical environmental benefits and likewise help facilitate more ready comparison (and recognition) of states with leading programs.

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[349] For work practice standards associated with well completion events, pneumatic pumps, and centrifugal compressors that require routing to certain combustion devices, the state requirements must ensure that the devices achieve 95 percent reduction of the VOC and methane that is captured. *See* TSD at 30 (completion combustion devices for well completions are assumed a achieve an average of 95 percent reduction), 162 (estimating 95 percent reduction for combustion devices associated with pneumatic pumps), 192 (assuming 95 percent reduction for centrifugal compressors with wet seals).

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