WESTERN ENERGY
ALLIANCE

December 4, 2015

Submitted via regulations.gov

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

RE: Western Energy Alliance's Comments for the Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (OOOOa); Draft Control Technique Guidelines (CTGs)—Docket ID Nos. EPA-HQ-OAR-2010-0505; EPA–HQ–OAR–2015–0216

Dear Administrator McCarthy:

Western Energy Alliance (the Alliance) appreciates the opportunity to comment on the proposed regulatory actions by EPA. The Alliance believes that United States Environmental Protection Agency (EPA or Agency) has overstepped its authority under the Clean Air Act (CAA) and has failed to develop an administrative record that demonstrates the need or benefit for the proposed rule. Finally, and perhaps most critically, the proposed rules will not have any meaningful impact on global climate change yet impose severe economic costs.

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

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

The following comments are divided into four general sections: (I) legal and policy issues related to OOOOa; (II) economic considerations and analysis related to OOOOa; (III) technical comments on proposed OOOOa provisions and draft CTG provisions where applicable; and (IV) comments on the CTGs. Because the issues in both proposals are so closely aligned, it makes sense in certain places to provide comments regarding those similar issues. Thus, we are submitting this same comment letter to both the OOOOa and CTG dockets, and in doing so incorporate by reference all applicable comments for each proposal separately into each docket and intend that all comments, where appropriate, be applicable to both proposals. The Alliance appreciates the opportunity to comment on these proposals.

I. Legal and Policy Considerations Related to OOOOa

a. EPA has abused its reconsideration authority under the CAA

EPA has exceeded its statutory authority under § 307 of the CAA by effectively promulgating an entirely new rule in the context of "amendments" to the new source performance standards (NSPS) in 40 C.F.R. 60, Subpart OOOO (77 Fed. Reg. 49,490 (August 16, 2012)) (NSPS OOOO or 2012 NSPS) and as part of the reconsideration process that has dragged on for over three years now. Section 307 grants EPA the authority to administratively reconsider objections raised to a rule if the person raising the objection "can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. § 7606(d)(7)(B).

Upon the petition of several stakeholders, including the Alliance,[1] EPA granted reconsideration and issued two reconsidered rules. *See* 78 Fed. Reg. 58,416 (Sep. 23, 2013); 79 Fed. Reg. 79,018 (Dec. 31, 2014). The spirit and intent of these reconsiderations—as it should be—was to fix technical components of the rule. While important to the functionality of the rule, these technical fixes were relatively minor in the overall context of the threshold legal and policy issues raised by the Alliance. *See e.g.*, the Alliance's Petition for Administrative Reconsideration attached hereto as Exhibit "A" (raising fundamental concerns about the rule under the CAA and the Administrative Procedure Act (APA), including whether EPA could ever make the case, legally or within APA governing principles, that methane regulation for this sector was warranted). When the Alliance filed its reconsideration petition and subsequently agreed to a stay of judicial review, we never thought that out of the reconsideration process would emerge an entirely new and different rule directly regulating methane and targeting sources outside the scope of NSPS OOOO.

[1] Out of an abundance of caution, the Alliance also filed protective petitions with the U.S. Court of Appeals for the D.C. Circuit under § 307(b) in 2012, and in response to both reconsiderations in 2013 and 2014, respectively. To allow the reconsideration process to run its ordinary course, the Alliance agreed to judicial stays in each of these court filings.

EPA's use of the reconsideration process to graft a new and separate rule onto NSPS OOOO has denied the Alliance and other stakeholders their right to timely judicial review and is an abuse of the authority granted by Congress to EPA under § 307(d)(7)(B) of the CAA. Although there is a dearth of case law construing the scope of EPA's authority under § 307(d)(7)(B), the plain language of the statute makes clear that EPA's reconsideration authority is not without limitation. Read in context, § 307(d)(7)(B) exists to provide stakeholders and EPA with the ability to fix or tweak rules without going to court—where doing so was not practicable during the course of the APA notice and comment period. This limited delegation is evidenced not only by the language quoted above, but also by the fact that the statute grants the ability to stay the effectiveness of a rule during reconsideration for only three months. *Id*. Congress did not intend § 307(d)(7)(B) to act as an administrative exhaustion requirement[2]; nor does it delegate to EPA the authority to hold a rule in reconsideration for over three years and promulgate an entirely new and separate rule from that being reconsidered (meanwhile precluding judicial review on threshold issues). EPA's actions have been *ultra vires* in this respect. EPA should conclude the reconsideration over NSPS OOOO, let any litigation proceed, and separately promulgate any new "methane" rules on their own administrative record.

b. The record does not demonstrate a need for these additional, duplicative regulations

EPA's decision to "directly" regulate methane in these OOOOa amendments is arbitrary and capricious. EPA has not provided any credible evidence on the record demonstrating the need for or the benefits of the rule. The decision to "directly" regulate methane in this proposed rule is confounding and circular, at best. On one hand the proposal concludes that "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." 80 Fed. Reg. at 56,599. Yet, on the other hand the rule concludes that methane reductions are simply an incidental benefit to volatile organic compounds (VOCs) reduction:

[2] Recent D.C. Circuit case law discussing Section 307(d)(7)(B) in a different context, however, has accepted EPA and the Department of Justice's (DOJ) position that when a party wants to challenge whether a final CAA rule was issued in violation of law, it cannot pursue judicial review on that issue unless and until it first files a petition under §307(d)(7)(B) and waits for EPA to take final action on that petition (even where the reconsideration process takes years). *See, e.g.*, American College of Environmental Lawyers Blog, "The D.C. Circuit Does It Again! Why Should EPA Even Bother to Propose CAA Rules?" (Aug. 10, 2015) (discussing three recent D.C. Circuit cases—*EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118 (D.C. Cir. 2015); *Mexichem Specialty Resins*, Inc. v. E.P.A., 787 F.3d 544, 553 (D.C. Cir. 2015)). The Alliance believes such construction of § 307(d)(7)(B) is incorrect and effectively forces parties, like the Alliance, to both petition for reconsideration and for judicial review, only to seek a stay in the courts. This outcome amounts to a denial of timely due process.

> Because VOC control technologies perform the same when used to control methane emissions, the BSER for methane is the same as the BSER for VOC. Therefore, we are proposing performance and operational standards to control methane and VOC emissions for certain emission sources across the source category. These proposed methane standards would require no change to the requirements for currently regulated affected facilities.

80 Fed. Reg. at 56,610 (emphasis added). It appears EPA wants it both ways—representing to the regulated community that the proposed controls are the same best system of emissions reduction (BSER) as currently implemented and are merely needed for "consistency," (*see* 80 Fed. Reg. at 56,599), while in the same breath, trumpeting the rules as groundbreaking and significant for their additional "methane" impacts. *Id*.

While EPA has proposed to regulate several source categories not regulated under the 2012 NSPS (*i.e.*, pneumatic pumps, oil well completions, fugitive leaks), the rest of the rule is duplicative regulation of already-covered sources. Only this time the rule takes credit for direct methane regulation, whereas in 2012 such methane reductions were labeled co-benefits for a lack of quality data. Unlike in 2012, however, this rule is justified almost exclusively on methane benefits and ostensible climate change impacts with only passing reference to VOC and hazardous air pollutant (HAP) reductions. *See e.g.,* 80 Fed. Reg. at 56,597 ("The EPA was unable to monetize all of the benefits anticipated to result from this proposal. The only benefits monetized for this rule are methane related climate benefits." (emphasis added)). Accordingly, we must question whether the rule truly is grounded in sound science regarding public health benefits, or merely advanced in furtherance of EPA's ongoing efforts to appease public critics with respect to climate change regulation.

In contravention of the grounding principles of administrative law, *see Motor Vehicle Mfrs. Ass'n of U.S., v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (requiring EPA to articulate a rational connection between the facts found and the choice made)(emphasis added), this rule appears to be driven by executive fiat rather than scientifically-based facts demonstrating a need to protect public health and the environment. *See* 5 U.S.C. § 706(2)(A) (prohibiting arbitrary and capricious agency action where EPA has not made rational policy decisions on the record and has not adequately articulated the basis for the conclusions underlying the rule). The preamble allots significant verbiage trying to justify both EPA's legal authority and ostensible policy rationale for the rule. Boiled down to its essence, however, the rule merely attempts to advance executive policy decisions through the guise of the CAA, but is based on slim, if not non-existent, scientific evidence that the rule will actually provide any public health or environmental benefits. Verbosity does not equate to rational articulation. Tellingly, the preamble contains a section "Events Leading to Today's Action," where EPA cites the 2009 GHG Endangerment Finding, President Obama's Climate Action Plan, the follow-up Climate Action Plan: Strategy to Reduce Methane Emissions, and the Administration's new goal to reduce methane emissions from the oil and gas sector by 40-45 percent by 2025—all executive actions "leading to the rule."

Notwithstanding the legal problems with the executive branch relying on its own policy directives, as opposed to statutory authority, to promulgate sweeping regulations, the rule simply does not advance such policies in any meaningful way. In fact, by making natural gas development more expensive and time consuming, the result will be less American natural gas production than without this rule, which is directly at odds with the President's overall climate goals. Specifically, since increased natural gas electricity generation is the primary reason that the United States has reduced Greenhouse Gas ("GHG") emissions, as recognized by the International Energy Agency, the Energy Information Administration and EPA's own data, this rule is actually counterproductive to efforts to address climate change.[3] By focusing on the small picture, the proposed rule is losing sight of the bigger picture.

EPA estimates that the methane reductions forecast to be achieved by the rule will "represent about 2 percent in 2020 and 4 to 5 percent in 2025 of the baseline methane emissions for [the oil and natural gas sector] reported in the U.S. GHG Inventory for 2013." 80 Fed. Reg. at 56,654. EPA does not advance these numbers with much confidence, noting they are based on "predicted activities" and not estimated sector-level emissions or robust emissions inventories. *Id.* EPA also justifies the rule on estimates that oil and gas production will grow by 25 percent by 2025. *See* *Methane Action Plan Press Release* (January 14, 2015)("Nevertheless, emissions from the oil and gas sector are projected to rise more than 25 percent by 2025 without additional steps to lower them."); *see also Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions* (January 14, 2015), https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1; *see also* 80 Fed. Reg. at 56,599 (without further support, citing to "rapid growth of this industry").

EPA has yet to provide any credible data supporting this 25 percent growth projection. To the contrary, methane emissions from oil and natural gas exploration and production (E&P) are 1.07 percent of total U.S. GHG emissions and the natural gas sector alone has reduced methane emissions by 38 percent since 2005. *See* *EPA, 2014 GHG Reporting Data* (2014). In 2013, "reported methane emissions from petroleum and natural gas systems sector" decreased by 12 percent from 2011, and the largest reduction came from hydraulically fractured natural gas wells (resulting in a decrease of 73 percent in emissions). *Id.* According to a study by the University of Texas, Austin, methane emitted from all upstream source categories at natural gas production sites represents just 0.42 percent of gross natural gas production volumes.[4] On a national scale, despite significant growth in production in this sector over the past several years, methane and other

[3] *World Energy Outlook*, International Energy Agency, 2011; *October 2015 Monthly Energy Review*, Table 12.6*,* EIA, November 24, 2015.

[4] *Measurements of methane emissions at natural gas production sites in the United* States, Proceedings of the National Academy of Sciences of the United States of America Vol. 110 No. 4, Allen et al., August 19, 2013.

emissions have continued to decline. EPA's own data bears these decreases out. *See* 80 Fed. Reg. at 56,606-56,607, Tables 2, 3(a) and 3(b) (showing the significant decrease in methane emissions from the oil and gas sector since 1990). In short, EPA's projections about growth and further extrapolations about the significance of this rule are simply not supported by the Agency's own data on this record; yet the rule appears to be grounded in the perceived need to reign in emissions from such growth.

Moreover, underlying these growth projections is a fundamental, yet incorrect, assumption that growth in production in this industry equates to a growth in emissions. *See e.g.*, 80 Fed. Reg. at 56,599 ("These emissions are expected to increase as a result of the rapid growth of this industry.") As we've noted elsewhere, technological and operational improvements in this sector continue to advance at remarkable rates and the emissions profile for new and modifies facilities is declining and will only continue to do so, particularly as operators move towards centralized gathering systems and tankless or pressurized tank facilities. For example, in Colorado, recent emissions inventories for the oil and gas sector demonstrate significant *decreases* (*i.e.*, more than 60 percent through 2017) in VOCs despite a growth in production. *See Overview of 2011 and 2017 VOC and NOx Emission Inventories*, Colorado Regional Air Quality Council, at 7 (November 19, 2015). These decreases are due to advances in technology, facility design, better emissions controls, and the inherent incentive to capture and sell as much methane as possible. New facilities in combination with growing infrastructure and voluntary and state-led emission control efforts are already resulting in decreases in sector emissions. Unlike virtually every other industrial sector, production in upstream E&P sources declines over time bringing with it declining emissions (of both VOCs and methane). The rule appears to ignore these fundamental realities. Until these contradictions are explained, any decision to regulate in the face of such overwhelming data would be unlawful.

c. The proposed regulations will have virtually no impact in terms of addressing climate change

Even if correct, the rule's estimated emissions reductions, based on an unsupported 25 percent growth rate and other incorrect or inaccurate assumptions/methodologies, represent a tiny fraction of all U.S. GHG emissions, and a virtually nonexistent fraction of global GHG emissions. Yet, the rule is justified largely on the basis of <u>avoiding</u> climate change impacts. *See* 80 Fed. Reg. at 56,605 ("[R]educing emissions of GHGs across the globe is necessary in order to <u>avoid</u> the worst impacts of climate change, and underscore the urgency of reducing emissions now."). As EPA notes, in 2013, total methane emissions from the oil and gas industry represented about 3 percent of all CO_2 equivalent (CO2(e))emissions in the U.S. *See* 80 Fed. Reg. at 56,654. Of this 3 percent CO2(e), and even assuming EPA's projected methane emissions and reductions supporting this rule are accurate (which we do not believe they are), the rule purports to reduce something much less than half of 3 percent. *See e.g.*, <u>FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions</u> (January 14, 2015), (calling the proposed rule "an important step to get us significantly along the way" to reducing methane emissions from the sector by 40-45 percent). While the rule strongly implies that total domestic contribution of GHGs from this sector is causing adverse climate change impacts, *see* 80 Fed. Reg. at 56,607 (comparing oil and gas GHG emissions with total U.S. GHG emissions "as an indication of the role this sources plays in total domestic contribution to the air pollution that is causing climate change"), the empirical evidence on this record contradicts these assertions. The proposal is devoid of any discussion or evidence demonstrating how less than a 1 percent reduction in domestic methane emissions will have any impact on climate change. The APA demands far more than regulation via the precautionary principle. *See e.g.*, *Washington Environmental Council v. Bellon*, 732 F.3d 1131, 1145 (9th Cir. 2013) (striking down Plaintiff's arguments that "any and all contribution of greenhouse gases must be curbed," and noting the common-sense notion that, as articulated in *Massachusetts v. EPA*, regulatory action should focus on reducing "meaningful contributions" of GHGs).

On a global scale the purported impact of the rule is infinitely smaller and far from "significant," despite EPA's statements to the contrary. Global methane emissions are nearly 7,000 million metric tons per year, whereas U.S. methane emissions are about 600 million metric tons per year, or about 8.5 percent of global emissions.[5] EPA estimates that the rule will reduce between 170,000 and 180,000 tons of methane in 2020 and 340,000 to 400,000 cumulative tons in 2025. 80 Fed. Reg. at 56,596. Even taking EPA's most ambitious, 400,000 tons, this rule provides a reduction of 0.0057 percent of global methane emissions. Global GHG emissions in 2010 totaled 46 billion metric tons of CO2 equivalents[6]. That means by EPA's most ambitious estimate, the proposed rule will reduce global GHGs by 0.0000092 percent to 0.000022 percent. Remarkably, somehow, the rule labels the forecast methane emissions reductions "significant" on a global scale. 80 Fed. Reg. 56,608 ("[T]he collective GHG emissions from oil and natural gas production and natural gas processing and transmission sources are significant, whether the comparison is domestic . . . or global."). The rule does not define "significant," but it is hard to imagine anywhere else where a 0.0057percent reduction of anything would be considered significant, particularly given that climate change is a global phenomenon, generally measured on the basis of country-by-country or even continent-by-continent contribution. By justifying the rule almost solely on climate change benefits and contributions towards mitigating climate change impacts from this single sector, the proposal falls far short of what is demanded under the CAA and APA to support the rule. Simply put, there is no logical or rational connection between the facts on the record and the decision being proposed, despite the lengthy preamble. While the Alliance supports common sense measures to address climate change, on this record, the proposal is not such a common sense approach and does not make even a slightly credible case that the regulation contemplated will have any impact on climate change or is otherwise needed.

[5] *Summary Report: Global Anthropogenic Non-CO2 Greenhouse Gas Emissions: 1990-2023*, EPA, December 2012
[6] *Global Greenhouse Gas Emissions* EPA, 2014

d. EPA must establish more than merely a rational basis for the proposal

EPA takes the position that "section 111(b)(1)(A) does not require another [endangerment] determination as a prerequisite for regulating a particular pollutant" and that such pollutant may be regulated "as long as the EPA has a rational basis for setting a standard for the pollutant." 80 Fed. Reg. at 56,601. The preamble goes on to state that "because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to oil and natural gas source category in order to establish standard of performance for the methane from those sources." *Id*. The Alliance respectfully disagrees with EPA's characterization of the applicable standard and its position regarding section 111. While it is true that section 111 operates differently than Title II of the CAA and sections 202(a)(1), 211(c)(1), and 231(a)(2)(A) with respect to endangerment, section 111 is not devoid of similar Congressional intent or language.

EPA acknowledges in this rule that endangerment under section 111 of the CAA "is based on determinations as to the <u>health or welfare impacts</u> of the pollution to which the source category's pollutants <u>contribute</u>, <u>and as to the significance</u> of the amount of such contribution." *Id*. (emphasis added). The statute bears this out, allowing a category of sources to be listed if "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). Thus, to list the source category, EPA initially established a nexus between pollutant emissions from the source category and public health and environmental benefits from such regulation. This involved consideration of whether the source contributed significantly to air pollution. As a matter of sound public policy and good-governance, and in light of the governing objectives of the statute, there should be a similar nexus required before regulating additional pollutants from that source, particularly where those pollutants were not even known or contemplated at the time of the listing decision.

On this latter point, the initial listing decision is 36 years old. Remarkable changes have occurred across this industry, which by EPA's acknowledgment, have dramatically reduced air emissions. In order to justify regulating GHGs from this sector, section 111 of the CAA, the APA, and sound public policy demand that EPA concretely establish that GHG emissions from this single sector are contributing significantly to or causing public health and welfare impacts.[7] Even without what we believe is necessary, *i.e.*, a separate endangerment finding, it certainly requires a more rational and better supported record than being advanced here.

As a legal matter, the preamble misstates and conflates the applicable standard for promulgating this rule (or any rule). The preamble suggests that EPA merely needs to

[7] EPA must make a similar two-part endangerment and significant contribution finding for each pollutant that it seeks to regulate from this source category.

demonstrate a rational basis for its decision to promulgate this rule.[8] 80 Fed. Reg. at 56,601 ("EPA interprets section 111(b)(1)(A) to provide authority to establish a standard for performance for any pollutant emitted by that sources category as long as the EPA has a rational basis for setting a standard for the pollutant."). EPA's position is incorrect and contrary to the plain language of section 111(b)(1)(A) of the CAA, which does not refer to a rational basis test. Rather, that section requires EPA to list a category of stationary sources if, in the Administrator's judgment, the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA § 111(b)(1)(A). This section requires EPA to list and regulate according to endangerment and significant contribution findings for particular pollutants and does not provide for a rational basis test.

Furthermore, any agency derives its authority to regulate, in the first instance, from the governing statute—here, the CAA. It is only after the agency has properly exercised that authority that its decisions are reviewed for rationality and arbitrariness. It is not the case, as the proposal appears to suggest, that an agency can promulgate regulations merely upon a showing that it has a rational basis to do so. Without a separate demonstration that contributions of methane emissions from this industry sector are causing public health and environmental impacts or otherwise contributing significantly to air pollution, the rule goes beyond EPA's statutory authority.

And even if it correctly interprets its statutory authority, it is incorrect in its interpretation of the applicable APA standard. "The standard of review of agency action alleged to be arbitrary and capricious is not simply whether there exists a rational basis for the action. Rather the inquiry is whether the decision was based on a consideration of relevant factors, whether there has been a clear error of judgment and whether there is a rational basis for the conclusions approved by the administrative body." *Mobil Oil Corp. v. Dep't of Energy*, 610 F.2d 796, 801 (Temp. Emergency Court of Appeals, 1979) (citing *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402, 416 (1971)). Where EPA fails to consider the

[8] The preamble cites to *National Lime Assoc. v. EPA*, 627 F.2d 416 (D.C. Circ. 1980) for this proposition. *National Lime* is distinctly different in fundamental respects, rendering it inapposite. First, the pollutant at issue in that case was particulate matter (pm) for which EPA had established a National Ambient Air Quality Standard (NAAQS). PM from lime manufacturing contributed directly to pm emissions for which the NAAQS had been set. This is entirely different from GHG emissions which lack a NAAQS and are global in nature. Second, the passage cited in the proposal is dicta from a footnote: the court did not decide whether regulating PM generated from lime manufacturing helped to achieve PM NAAQS attainment. Finally, it is worth noting that the proposal also cites this case for the premise that EPA's decision not to regulate NOx, SO2, and CO from lime plants supports its decision here. 80 Fed. Reg. at 56,601. Interestingly, EPA decided not to regulate CO from the lime manufacturing industry because CO emissions from that sector would equate to less than 1 percent of primary NAAQS. *National Lime*, 627 F.2d at 426, n. 27. This is almost exactly the level of U.S. methane emissions estimated to be affected by this rule (see discussion below).

governing statute's objectives or authority *before* promulgating the rule, its action is beyond its statutory authority. *Id*.

The Alliance does not believe that Congress intended or contemplated the approach taken by EPA here—that is, carte blanche authority to regulate any pollutant from any listed source category merely upon the showing of a "rational basis." Such an approach misstates APA requirements and ignores the specific language of section 111(b) of the CAA and the underlying objective of the CAA "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of the population." 42 U.S.C. § 7401(b)(1). EPA must consider section 111 and the CAA's objectives and do so in a manner consistent with the APA. This requires examining the relevant data and articulating a satisfactory explanation in terms of benefits to public health and welfare that are needed and will result from EPA action. *See Burlington Truck Lines, Inc. v. U.S.*, 371 U.S. 156, 168 (1962). On this record, the proposed rule simply does not meet these well-established standards for rulemaking and stands a very good chance of being struck down on judicial review.

II. Economic Considerations

a. The Regulatory Impact Analysis (RIA) and related cost and benefit conclusions are not credible

Attached as Exhibit "B" is an economic assessment report from the economics firm, John Dunham and Associates (the Dunham Report). The Dunham Report confirms two critical and legally fatal flaws with the proposed rule: (1) it is not grounded in sound science or economics rendering it arbitrary and capricious under the APA and the CAA; and (2) it is driven exclusively by the Administration's policy initiatives related to climate change as opposed to the governing principles of the CAA—principally, protecting public health and welfare. As the Dunham report details, the proposal skirts the basic requirements of a RIA; and even where it does endeavor to engage in some regulatory impact analysis, the methodologies and assumptions are so flawed as to render the conclusions meaningless. One need look no further than EPA's conclusions in the preamble, which draws on the RIA, that reducing global GHGs by 0.0000092 percent to 0.000022 percent is "significant." In sum, while the proposed rule may conform to the Administration's climate change agenda, it fails to meet the basic requirements of the APA and the CAA. The following is a bulleted summary of the major conclusions in the Dunham Report:

- The Office of Management and Budget (OMB) sets forth 16 best management practices (BMPs) in its RIA agency checklist. The RIA failed to perform, in any respect, 10 of these 16 BMPs.[9] Failing to follow those basic procedures casts into doubt the validity of the RIA.

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[9] *Agency Checklist: Regulatory Impact Analysis*, Office of Management and Budget.

- The RIA does not perform a meaningful alternatives analysis. Highlighting the notion that this proposed rule was a foregone conclusion before the results of the economic analysis were even finished, the RIA simply looks at reducing monitoring requirements from semi-annual to annual. It entirely omits consideration of other regulatory alternatives, including: not taking any action at all; deferral to state or local regulation; the use of economic incentives to drive behavior; market-oriented approaches; different compliance dates; or different requirements based on firm size. As a result, the proposed rule entirely fails to consider the costs and benefits of alternative approaches, or whether these costs of the rule (*e.g.*, $330 million in 2025 capital estimates) are not better spent on some other measure or activity.

- The reasons stated for the rule are solely to reduce the effect of methane emissions on climate change, yet the benefits calculated do not demonstrate how this rule will meet this need. This is because the RIA fails to establish in any meaningful way, beyond broad, passing discussion of global climate change effects, that the methane emissions avoided through this rule will impact climate change in some way. In fact, OMB requires agencies to establish a baseline assessment of what would happen in the absence of the rule, with a focus on the costs and benefits absent the rule accruing to U.S. citizens. The RIA is devoid of any such baseline calculation or assessment. Without this required assessment, it is *impossible* to determine whether there are any climate change benefits of the rule at all, much less climate change benefits that accrue to the U.S. economy. Similarly, it is *impossible* to determine if the rule will have any meaningful effect on the overall factor being measured—the perceived economic cost of climate change. In addition, the rule compares global climate benefits to domestic costs, vastly skewing the cost/benefit analysis in favor of the rule.

- There is no meaningful analysis of the distributional impacts of the proposed rule, *i.e.*, impacts of the proposed action across the population and economy divided up by a range of demographic and economic categories. Such analysis is particularly important where, as here, the proposed regulation focuses on one industry. Higher costs in one industry often encourage investment in another. With respect to domestic oil and gas and the well-recognized mobility of capital within this sector, there is a particularly acute risk for this industry that overly-burdensome regulation will result in the transfer of capital activity from the U.S. to other countries, such as Russia, Mexico, Iraq, or Nigeria. The RIA does not account for any of these potential consequences.

- The RIA completely ignores the potential impact the proposed rules may have on marginal wells. Higher regulatory costs may result in a significant increase in the number of marginal wells, with potentially dramatic effects on U.S. energy production and employment, particularly in a low commodity price environment. For example, even at high commodity prices, a prior analysis by John Dunham shows that in 13 western states about 72.5 percent of currently active oil wells and 63.7 percent of natural gas wells could be considered "marginal" and already operating at a loss once development and remediation costs were considered.[10] It does not take a large additional operating expense to force the decision to shut-in such wells. This concern is especially great for the Alliance's members.

- The RIA does not conduct an uncertainty analysis, yet EPA's conclusions are replete with massive uncertainty about the ostensible benefits of the rule, which again are grounded only in climate change impacts. The mere fact that no credible health benefits were estimated is problematic and atypical of prior air quality rulemakings. And the benefits that are asserted are wildly inconsistent and based on cherry-picked data. The proposed rule relies on an EPA paper (Marten, 2014[11]) to estimate methane-specific costs. The RIA also estimates a 239 percent difference in the potential range of "climate change" impacts from methane emissions and benefits ranging from $88 million to $550 million. The failure to perform an uncertainty analysis under these conditions is inexcusable and contravenes sound principles of economics, statistics, and public policy, and the APA.

In sum, the RIA is woefully deficient and does not meet minimum APA rulemaking standards. EPA's assessment of the potential costs and benefits from the proposed rule are unsupportable and strain credibility. On its face, it is difficult to comprehend how the elimination of an inconsequential amount of fugitive methane emissions from new and modified oil and natural gas sources (or existing sources in non-attainment areas) will have any climate change impact here in the U.S., or globally. Yet, neither the RIA nor the preamble directly addresses this very basic question. Instead, the preamble and RIA are replete with general statistics about climate change, climate change effects, GHG emissions generally, and a questionable assessment regarding the social cost of methane. More external review and public comment is needed on the issue of costs and benefits, given that tangible differences exist between CO_2 and methane (*e.g.*, atmospheric lifetimes and how those can change the appropriate discount rates), and the Alliance respectfully requests EPA offer the same to the public and interested stakeholders.

b. Comment on EPA's cost effectiveness determinations for fugitives and leak detection and repair (LDAR)

As an initial matter, the Alliance supports no more than an annual LDAR frequency for all sources. While we stated during initial public comment that we were encouraged by the move away from quarterly to semi-annual, upon further review of the rule we do not believe a semi-annual frequency requirement is a cost-effective approach. In this respect,

[10] *Memorandum: Cost-Benefit Analysis of Proposed NSPS Amendments for the Oil and Natural Gas Industry*, J. Dunham, 2012.
[11] *Incremental CH4 and N2O mitigation benefits consistent with the US Government's SC-CO2 estimates*, Marten et. al., 2014.

we support the other national trade associations. The following discussion provides a basis for this comment as well as a critique of the proposal's over-reliance on Colorado's program.

EPA solicits comments on the appropriateness of the percentage of emission reduction level that can be achieved with quarterly, semiannual, and annual monitoring program frequencies. *See* 80 Fed. Reg. at 56,635. As an initial matter, the rule "find[s] that the cost of monitoring/repair based on quarterly monitoring at well sites using [optical gas imaging or "OGI"] is not cost-effective under either [the single- or multipollutant approach]." 80 Fed. Reg. at 56,636 (emphasis added). Given the inaccuracies in assessing costs, as described in more detail below, the Alliance agrees with this conclusion. The Alliance believes that if more accurate cost and benefit data were used, quarterly monitoring would be even more costly per ton of pollutant reduced (*i.e.*, even less cost-effective) than estimated in the proposal. In light of this express finding, there does not appear to be any legal authority to impose a "step-up" approach that would require operators with higher than a 3 percent leak rate over a 12-month period to move to quarterly monitoring.

The rule also relies on fugitive emission factors from AP-42 to estimate methane and VOC fugitive emissions from a typical oil and natural gas and oil well facility, respectively (4.5 tons per year (tpy) methane and 1.3 tpy VOC from oil and natural gas; 1.1 tpy methane and 0.3 tpy VOC from oil well facility). 80 Fed. Reg. at 56,635. The AP-42 emissions factors are taken from a 1995 EPA protocol. The outdated protocol is based on 24 facilities and a sample size totaling 368 components, with the majority of the 24 facilities being "uncontrolled," *i.e.*, no LDAR program. The use of AP-42 emission factors, aside from being 20 years old and not accounting for improvements in component quality and other equipment, vastly over-report and over-estimate the typical level of fugitives at an oil and natural gas facility. Inaccuracies in this respect are further compounded by the fact that this proposed rule applies only to new and modified sources that use state of the art components and equipment, and are designed to minimize leaks. The end result is an overly conservative and inaccurate estimation of fugitive emissions; skewing the purported benefits from the rule and affecting EPA's determination on cost-effectiveness.

In addition, EPA appears to adopt estimates made by the state of Colorado in the run up to the 2014 rulemaking with respect to VOC/methane reductions anticipated from the proposed Colorado LDAR program. 80 Fed. Reg. at 56,635. (citing the Air Pollution Control Division Initial and Final Environmental Impact Analysis). EPA selected 80 percent VOC/methane emission reduction, to be expected from a quarterly frequency, 60 percent reductions from a semiannual frequency, and 40 percent reductions from an annual frequency).[12] The Colorado estimations, however, were fraught with error and do not represent conditions actually experienced. Moreover, EPA skews Colorado's data points without support or explanation. For example, the Colorado EIA estimates 60 percent

[12] Colorado's conclusions in this respect generally relied on EPA's "Leak Detection and Repair Compliance Assistance Guidance: A Best Practices Guide" (EPA-305-D-07-001, October 2007) and EPA's "Protocol for Equipment Leak Emission Estimates" (EPA-435/R-95-017, November 1995).

reduction for quarterly monitoring frequency whereas EPA assumes 60 percent reduction for a semiannual monitoring frequency, and the Colorado EIA estimates 80 percent reduction for monthly monitoring frequency whereas EPA assumes 80 percent reduction for a quarterly monitoring frequency.

Colorado's estimates, which were based on inflated and inaccurate fugitive emission estimations and factors to begin with, assumed that LDAR benefits both increase with the frequency of inspection and remain constant over time. Neither of these assumptions is true. First, Colorado's estimates were based on EPA guidance that applied a "rule of thumb" assessment and did not actually conclude that benefits from an LDAR program increase with frequency or stay consistent over time. Second, the EPA guidance relied upon addressed fugitive emission reductions at chemical plants and petroleum refineries (not smaller, scattered oil and gas facilities), utilized outdated data, and employed simple averages as opposed to a more accurate distribution of components that would be expected at smaller oil and gas facilities. *See also* 80 Fed. Reg. at 56,635 (EPA citing to a 1996 report to estimate fugitive emissions component counts).[13] These and other errors combined to result in inaccurate estimates about the cost-effectiveness of the Colorado LDAR program and the ostensible benefits of increased frequency in particular.

Contrary to the conclusions drawn in the Colorado rulemaking which EPA is apparently relying on to justify this rule, actual experience with the LDAR program *at upstream oil and natural gas facilities* demonstrates: (1) that following the implementation of an LDAR program, leak rate frequency found upon initial monitoring drops significantly during subsequent monitoring to less than 1 percent; and (2) that providing operators the flexibility to focus on high emitting and likely-to-emit components delivers the most cost-effective benefits. Experience also demonstrates that these low, post-initial monitoring leak rates generally are sustainable over the long term. *See Colorado Regulation 7/Litigation Support*, prepared for WPX Energy, Inc. by Trihydro Corporation, at 1-1 (January 6, 2015).[14]

In addition, reliance on the Colorado program's cost-effectiveness evaluation is erroneous. As the Alliance has pointed out before, the Denver-Jules (D-J) Basin in Colorado is a unique operating field, not reminiscent of many (if not most) other parts of the country. As the D-J is located near major population centers, operators enjoy relatively easy access to their facilities along well-established roads and highways, in a field with well-developed gathering infrastructure. These circumstances are more likely to reduce the costs and

[13] Significant advances have been made in the physical equipment installed at oil and gas facilities since 1996 (including low-leak valves, upgraded flange packing materials, and higher quality mechanical seal pumps).
[14] *Available at*: ftp://ft.dphe.state.co.us/apc/aqcc/Oilpercent20&percent20Gaspercent20021914-022314/PREHEARINGpercent20STATEMENTS, percent20EXHIBITSpercent20&percent20ALTERNATIVEpercent20PROPOSALS/WPXpercent20Energy percent20Rockypercent20Mtnpercent20LLCpercent20and percent20WPXpercent20Productionpercent20LLC/WPX-PHSpercent20EXpercent20A.pdf.

burdens associated with an LDAR program when compared with other, more remote oil and gas fields across the country. So even if the Colorado data, in fact, demonstrated cost-effectiveness across some or all of the Colorado-operated facilities, those findings will not necessarily translate nationwide, particularly given that travel costs and employee time are the single biggest drivers of an LDAR program's overall costs. Conversely, many of the production basins in the West are in remote locations far from major urban areas. We strongly caution EPA not to solely rely on Colorado's pre-rule estimates regarding the cost-effectiveness of the Colorado LDAR program and Colorado's conclusions about how (if at all) frequency and consistency of LDAR inspections relate to emission reductions.

In addition, providing operators flexibility in developing LDAR programs similar to directed inspection and maintenance (DI&M) programs tailored to their specific facilities or groups of facilities provides significantly greater fugitive emissions benefits at a much lower cost than the type of rigid and inflexible program being proposed nationwide by EPA (or being implemented in Colorado). *See Management of Fugitive Emissions at Upstream Oil and Gas Facilities*, Canadian Association of Petroleum Producers at 1 (In the upstream oil and gas sector "[o]nly a small percentage of the equipment components have any measurable leakage, and of those only a small percentage contributes to most of the emissions. Thus, the control of fugitive emissions is a matter of minimizing the potential for big leaks and providing early detection and repair.") In this respect, the Alliance strongly supports a flexible approach and believes that, at most, EPA should be focusing its LDAR program on high or "gross" emitting components/facilities. *See* 80 Fed. Reg. at 56,637 ("[W]e solicit comment on whether the fugitive emissions monitoring program should be limited to 'gross emitters.'") Allowing operators to focus monitoring efforts on the components that are most likely to leak, and those that are most likely to have the highest leak rates, maximizes both the emissions reductions and cost-efficiencies of an LDAR program.

III. Technical comments

The following section contains the Alliance's technical comments on the proposed rules (OOOOa and CTGs, where applicable). These comments are made in an effort to improve and correct the proposed rules from a technical and implementation perspective, but as noted above, we believe there are more fundamental legal and policy concerns with these rules that must be addressed before promulgation.

a. Leak Detection and Repair (LDAR)

The proposed LDAR program is highly problematic in numerous respects and would be extremely difficult and costly to implement; all while providing little emissions benefit over and above state and voluntary operator programs. There are proven feasible and cost-effective alternatives to EPA's proposed LDAR program. These alternatives are flexible, cost-effective, and provide the same (or improved) benefits to the environment. Such alternatives include corporate-wide programs executed voluntarily and compliance with various state-mandated regulatory programs (such as in Wyoming and Colorado). Other programs—such as those modeled after D&IM programs—allow operators to focus on high and frequent emitters. Our members have extensive experience implementing voluntary programs, and we look forward to working with EPA and partnering with state regulators to apply this knowledge and experience.

i. OOOOa's percentage-based approach to LDAR inspections is infeasible.

While we appreciate the purpose behind an incentive-based LDAR program—one that rewards operators who follow diligent inspection and repair protocols—the proposed step-up/step-down approach is unworkable. The proposal requires operators to track the percentage of leaking components at every possible location; both to first establish a baseline, and then to track changes, modifications, and repairs. Tracking these components will require operators to use extraordinary software and database sets that are simply not realistic, practical, or cost-effective.

The proposed LDAR program is tantamount to similar LDAR requirements for gas plants. Unlike gas plants, however, well sites and compressor stations are typically unmanned and do not provide operators with easy access to spare parts for making repairs. It is unreasonable to expect a record of every valve, flange, and gasket across thousands—or, possibly tens of thousands—of wells and production facilities, and then to track changes to the same year-after-year. The data management burdens alone are not practical or reasonable. And this is to say nothing of the implementation burdens that would be required: including hiring crews; training on component identification; implementing a tagging program, etc. Small producers would be disproportionally affected, as they lack the IT management capabilities to develop and maintain such extensive databases. Moreover, the costly and complex undertaking of building and maintaining such a database imposes significant costs on operators and ultimately end-consumers, while providing no environmental benefit. States such as Colorado, Wyoming, and Utah already achieve similar, if not greater, environmental benefits than promised under the proposal. But these states do so without the logistical challenges of a percentage-based approach. We strongly recommend the rule not include a program provision that would require extensive data management (*i.e.*, no step-up/step-down provision).

ii. The proposal contains an overly-prescriptive approach to LDAR.

The Alliance supports a fixed, annual instrument-based survey for LDAR. As we stated in September at the public meeting, we were encouraged by EPA's move away from quarterly to semi-annual. Upon further review of the proposal we believe a fixed, annual instrument-based LDAR frequency is the only appropriate approach. For one, it is notably more cost-effective. Were EPA to correct the inaccurate assumptions and methodologies concerning LDAR costs (*see* **Section II(b)** above), we question whether a semi-annual frequency would remain cost-effective.

As written, the proposal requires operators to monitor leaks across an entire field, with multiple facilities, on different and changing inspection schedules. This monitoring burden is in addition to the challenges associated with calculating the leak rate at every single facility, as described above.

Recent studies have demonstrated that following an initial inspection, subsequent LDAR surveys offer diminishing returns in terms of leak reductions. Take, for example, a member company's recent analysis. This Alliance member analyzed emission reduction levels associated with different fugitive emission control survey frequencies on operations in Wyoming. The member concluded annual fugitive emission control monitoring results reduces emissions by 52 percent—a level of reduction higher than the 40 percent EPA estimated. The member company also concluded semiannual monitoring results in a 57 percent reduction in emissions; this is similar to the 60 percent reduction estimated by the proposed rule. Finally, the study concluded quarterly monitoring only provides a 61 percent reduction in emissions; this is significantly lower than the 80 percent reduction estimated by the proposed rule. Ultimately, the member company's analysis shows increased inspection frequencies does not result in the emissions reductions as contemplated by the proposed rule. Put another way, the emission reduction potential of each LDAR inspection decreases drastically when the frequency of the inspections is increased.

Additional studies, referenced by the American Petroleum Institute (API) in its comments on the proposed rule (and discussed in more detail above in **Section II(b)** above) demonstrate that the most important factor in a successful LDAR program is the initial inspection. A semi-annual or quarterly inspection schedule offers little in the way of added environmental benefit, but substantially increases program cost. A third-party survey indicates a voluntary LDAR program still exhibits a leak rate of less than 1 percent, even in fields without a current regulatory LDAR program.[15] These studies suggest the proposal's estimated leak rate is overestimated.

In addition to monitoring frequency, there are other concerns with the proposed LDAR program. The proposal suggests relying solely on OGI or Method 21 for monitoring and repair—but such constraints are self-limiting and ignore existing, successful LDAR programs. OGI and Method 21 are reasonably effective technologies for LDAR applications; however they are imperfect and may not function well in all situations. For example, OGI is also not a quantitative tool and depending on the camera, it may also detect water vapor and heat signatures. An OGI camera survey may not always be able to tell an operator whether a repair is necessary since it is not quantitative. During periods of overcast skies, high winds, or inclement weather, OGI technology is unable to effectively detect hydrocarbon vapors. In certain parts of the West such overcast and windy conditions can persist for long periods during the winter. Lastly, OGI cameras are generally not intrinsically safe and would require a hot work permit in many instances. Thus, a prescriptive LDAR rule that relies too heavily on an OGI monitoring plan will be ineffective in many basins across the West for much of the year. While OGI cameras have their place

[15] *Upstream Leak Detection Study in Preparation for NSPS OOOO Version 2.0,* AECOM, June 3, 2015.

in certain circumstances, they are inherently limiting in their utility within an LDAR program—particularly one so focused on defining leaks and leak percentages such as that being proposed. For a more effective LDAR program, the rule should give operators flexibility to select the ideal monitoring technology for the prevailing conditions.

The proposed rule requires operators to resurvey a repaired leak with only Method 21. This is impractical. Without precise quantification, an OGI camera can detect emissions to about 10,000 parts per million (ppm); yet the resurvey using Method 21 requires repairs to a 500 ppm leak threshold. We recommend revising the resurvey/repair threshold using Method 21 to 10,000 ppm to maintain consistency between the two methods, provide the same 10,000 ppm threshold for leak detection (with OGI) and repair survey and avoid a scenario where emission are not detected via the OGI (because they are less than 10,000 ppm) but they are detected using Method 21. The difference in emissions between a 500 ppm leak and a 10,000 ppm leak is *de minimis*; so maintaining this consistency would not compromise the program's environmental benefits.

In addition, revising the proposed rule to reflect a 10,000 ppm leak threshold is consistent with existing NSPS equipment leak standards. *See e.g.,* NSPS, Subpart VV, 40 C.F.R. §§ 60.482-2(b)(1), 60,482-7(b), 60.482-8(b) (providing a leak detection threshold of 10,000 ppm for certain pumps, valves, pressure relief devices and connectors and identifying a "repaired" leak in § 60.281 as when "equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482-2(b)(2)(ii) and (d)(6)(ii) and (iii), 60.482-3(f), and 60.482-10(f)(1)(ii), is re-monitored as specified in § 60.485(b) to verify that emissions from the equipment are below the applicable leak definition"). *See also* NSPS, Subpart KKK, 40 C.F.R. § 60.632(a)(requiring compliance with NSPS, Subpart VV).

For small operators, the cost of an OGI or Method 21-based LDAR program will be particularly burdensome. In some instances, these small operators have only a few wells or wells with low production volumes; and therefore the cost of the equipment or implementing the program may vastly exceed the emissions being saved. As an alternative to expensive instrumental surveys, we recommend that EPA allow for soap bubbles as a potential screening method (only where appropriate, considering the caveats in Section 8.3.3.1). EPA already recognizes the effectiveness of soap bubbles in its Method 21, Section 8.3.3 procedure.

The proposed rule also would stifle innovation of more effective monitoring and measuring equipment. Instead of prescribing two methodologies, the rule should permit flexibility, in accordance with other successful LDAR programs. For example, in Colorado, 5 C.C.R. 1001-9 (Regulation 7) gives operators some flexibility in choosing a leak detection technology. EPA's vendor testing program for flares and combustors may also be another viable option. Under this program, EPA allows vendors to test according to protocols set by EPA and determine standard operating procedures for control devices. New and innovative technologies are constantly involving in this space and the rule should encourage not stifle such progress. We encourage EPA to make very clear in the rule that new technologies are encouraged and will be approved and allowed through a straightforward and expedited review process (*i.e.*, avoiding an onerous, years-long application process that would otherwise be applied to actual emissions control devices or continuous emissions monitoring systems). We would welcome the opportunity to work with EPA to determine what methods should be approved for LDAR monitoring and verification.

iii. Operators currently engage in voluntary corporate monitoring programs.

The proposed OOOOa solicits comment on:

> [C]riteria we can use to determine whether and under what conditions well sites and other emission sources operating under corporate fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). 80 Fed. Reg. at 56,596.

We appreciate the opportunity to comment on corporate fugitive monitoring plans. We stress the proposed rule is soliciting comment on a *work practice*, which should not be treated as a performance standard for compliance purposes. Instead, the proposed rule should be modified to accept corporate-wide fugitive emissions monitoring plans in lieu of further monitoring per OOOOa. Such corporate plans have been implemented for years by many of the leading companies in the industry, and these plans act as prime examples of industry taking the lead on improving operations while providing environmental benefits. Now is not the time to stifle or punish such efforts by imposing a prescriptive, one-sized-fits all program that effectively sends these companies back to the drawing board. The Alliance believes the choice to accept a corporate-wide plan is not merely a minor point. Rather, depending on how the final rule treats this issue, it will effectively send one of two signals to the regulated community: a positive message that it pays to do the right thing or a negative message that no good deed goes unpunished.

By way of example, we received input from our members on some current corporate fugitive monitoring plans.

- **Powder River Basin, Wyoming (WY)**: Operator conducts quarterly thief hatch inspections (performed by third-party consultants) and OGI camera monitoring.

WY permits require quarterly audio/visual/olfactory (AVO) and annual OGI or Method 21.

- **Williston Basin, North Dakota (ND)**: Operator conducts annual OGI camera monitoring and repairs.

In some instances, operators will visit locations on a daily basis. These visits almost always include general audio/visual/olfactory (AVO) monitoring, with any leaks noted and repairs made. Operators also are implementing or developing preventative maintenance programs around the country. We raise these examples so that EPA can understand what these corporate voluntary programs may look like, and to solicit feedback from EPA on the sufficiency of these programs.

iv. LDAR exemptions are inadequate.

The rule proposes a 15 barrel of oil equivalent per day (BOE/d) threshold for exemption from its wellsite fugitive monitoring based on the average of the first 30 days of production*. See* 80 Fed. Reg. 56,612. We request clarification on whether this exemption will apply to any well that falls below this 15 BOE/d threshold. In addition, we request clarification on the following scenario: if a well is above 15 BOE/d during the first 30 days of production, will it remain in the OOOOa LDAR program indefinitely?

The rule might also consider an alternative exemption: based instead on 300 gas-to-oil ratio (GOR). The proposed rule recognizes oil wells with little to no gas volumes should be exempt from reduced emission completion (REC) requirements based on a low GOR of 300. If gas volumes are this low, gas gathering is uneconomic, and it is no longer cost-effective to require leak detection for little to no methane (or natural gas) reductions. The proposed rule should be revised to exempt low production wells from its LDAR requirements regardless of their initial production rate.

v. The proposal fails to allow sufficient time for repairs.

The proposed rule requires 15 calendar days for repair of any leaks detected, except where it is technically infeasible or unsafe during unit operations. The proposed rule notes this 15-day repair window is feasible, based on the industry's past experience in compliance. However, the proposed 15 day repair window actually applies to downstream facilities, not to production facilities. This is not a sufficient basis for feasibility: downstream facilities, such as gas processing plants or other large facilities, are manned 24 hours per day and 7 days a week. These downstream facilities generally have many spare components immediately available for repairs. A remote wellsite is vastly different from a downstream facility, and as such, an operator of a wellsite requires additional time to conduct repairs.

More often than not, it is unfeasible for an operator to conduct repairs at the time of inspection. Additionally, replacement parts may not always be available. In instances where parts may be back-ordered, it is entirely conceivable that repairs could be delayed by 15 calendar days or more. For example, the state of Utah recognizes that repairs may not always be feasible due to lack of available parts. In order to get around this problem, Utah offers the following solution, which we recommend that EPA adopt in its rule as well. In the terms of one approval order, Utah stipulates the following:

> If a leak is detected at any time, the owner/operator shall attempt to repair the leak no later than 5 calendar days after detection. Repair of the leak shall be completed no later than 15 calendar days after detection, unless parts are unavailable or unless repair is technically infeasible without a shutdown. The owner/operator shall inspect the repaired leak no later than 15 calendar days after the leak was repaired to verily that it is no longer leaking.
>
> If replacement parts are unavailable, the replacement parts must be ordered no later than 5 calendar days after detection, and the leak must be repaired no later than 15 calendar days after receipt of the replacement parts.
>
> If repair is technically infeasible without a shutdown, the leak must be repaired by the end of the next shutdown. If a shutdown is required to repair a leak, the shutdown must occur no later than 6 months after the detection of the leak unless the owner/operator demonstrates that emissions generated from the shutdown are greater than the fugitive emissions likely to result from delay of repair.

Such flexible approach is consistent with the spirit and intent of an LDAR program, which is a work practice standard designed to encourage more efficient and better operations. Moreover, without language permitting operational flexibility to locate appropriate parts, there would be a significant disincentive to accurately find and fix leaks—defeating the purpose of the program. The Alliance suggests the proposed rule be modified to include a similar provision in the final rule.

vi. LDAR should be limited to gross emitters.

EPA is soliciting comment on whether its LDAR program should be limited to gross emitters. We understand gross emitter as a term used to describe data that indicates a majority of fugitive methane and VOC emissions come from a select minority of components. We strongly support focusing a LDAR program on gross emitters, as doing so provides the most cost-effective, environmentally beneficial approach.

The Alliance believes the rule can, and should, limit its fugitive emissions control program to certain high or "gross" emitting components. Components operating at these higher pressures are more likely to emit greater amounts of fugitive emissions should a leak occur. For example, to target "gross emitters," the proposed rule can focus on: (1) the most common sources of leaks, such as valves, open-ended lines, and pumps, or "high motivated operation equipment"; and (2) only those components with the potential to operate at or above sales line pressure. Focusing on gross or high emitters will result in the same environmental benefits, and still address the components of primary concern

EPA has successfully used this flexible approach elsewhere, including in its DI&M program for Natural Gas STAR. This allows operators to maximize the cost effectiveness of their LDAR programs by focusing the most resources on quickly identifying and addressing the large leaks. A program that fails to recognize the importance of prioritizing the larger leaks will, by definition, not be the most cost-effective regulatory approach (if it is cost-effective at all). Operators will spend time and resources tracking down very small leaks, rather than identifying and correcting the large leaks as quickly and efficiently as possible.

vii. The rule incorrectly defines "fugitive emissions component."

The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. For example, in the NSPS OOOO requirements for gas processing plants, "fugitive emission components" are effectively included within the definition of "*equipment." See* 40 C.F.R. § 60.5430 *("Equipment,* as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.")

The proposed rule proposes the following definition of fugitive emissions component, which is notably more expansive:

> *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to 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. Devices that vent as part of normal operations, such as a natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump would be considered fugitive emissions.

80 Fed. Reg. at 56,638. EPA has provided no rationale for such a significant deviation from the longstanding approach as reflected in NSPS OOOO. As a matter of regulatory consistency and efficient program implementation, the definition of "fugitive emissions

component" in OOOOa should not be more expansive than other similar regulatory definitions in NSPS OOOO.

Moreover, the definition of "fugitive emissions component" above incorrectly includes equipment that should be listed as devices that vent as part of normal operations. Specifically, included within the definition of "fugitive emissions component"—but should not be—are "thief hatches or other openings on a storage vessels (part of closed vent system, not relevant to an uncontrolled storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters." 80 Fed. Reg. at 56,638. Each of these vents as part of normal operations, and must be allowed to within the confines of these pressurized systems for very serious safety and other operational reasons.

In addition, "closed vent system" requires its own definition. The proposed rule conflates the separate closed vent systems with fugitive emission components. The closed vent system monitoring requirements can (and should) stand alone; otherwise, the rule creates duplicative compliance requirements. It may also result in unintended enforcement consequences.

If the fugitive emissions components definition is not changed to remove equipment that is designed to vent, the rule may be applied to tanks not subject to NSPS OOOO. We do not believe EPA intended this outcome, nor did it consider the costs or other impacts of this outcome. Put simply, this provision of the proposal contains very serious flaws, which do not account for operational realities at upstream oil and natural gas facilities, and is in need of significant changes prior to finalization.

viii. Fugitive emissions at modified well sites and compressor stations.

The proposed definitions of fugitive emissions at modified well sites and compressor stations should be amended. 80 Fed Reg. at 56, 664. Well completions from hydraulic refracturing are not an affected source under NSPS OOOO, and therefore, a modification to a well site should not include a well that is hydraulically refractured. This revision will provide consistency with the well completion provisions. In addition, a physical change to an existing compressor at a compressor station may not be accompanied by an increase in components. Therefore, the definition of modification to a compressor station should not include a physical change to existing equipment.

The proposed rule also solicits comments on whether fugitive emission requirements should apply to all fugitive emission sources at modified well sites (80 Fed. Reg. at 56,638), and modified compressor stations (80 Fed Reg. at 56, 643), or whether the rule should just apply to the fugitive sources connected to the fractured or added well or compressor, respectively. For well sites, fugitive emission requirements should only apply to those components connected to a fractured or added well. For compressor stations, fugitive emission requirements should only apply to those components connected to the added compressor.

ix. Well site definition should be amended to avoid confusion.

The proposed definition of "well site" includes tank batteries (including central tank batteries) and injection wells. Section 60.5365a(i)(2) exempts wellhead-only sites from OOOOa fugitive emissions requirements, stating "[a] well site that only contains one or more wellheads is not an affected facility under this subpart." To clarify this exemption and avoid possible confusion, the Alliance recommends revision to include italics in § 60.5430a as follows:

> *Well site* means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at § 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries), *and excludes wellhead-only well sites.*

x. LDAR compliance date is unreasonable.

Proposed 40 C.F.R. § 60.5370a(a) requires compliance within 60 days after publication of the final rule in the Federal Register. This is not feasible, realistic, or reasonable. One of the most difficult aspects of implementing a new LDAR program is the time required to set it up. This includes tracking systems (databases), allocating or hiring personnel, and conducting training. Sixty days is not even close to sufficient time for operators to perform these tasks for hundreds, if not thousands, of facilities. In addition, as experienced in Colorado, there may not be sufficient, trained third parties available to implement these programs in certain areas. There will be numerous operators (or contractors) that will have to invest in new monitoring equipment. Lead time alone for ordering monitoring equipment, such as OGI, is, itself, approximately 60 days. When OOOOa is finalized, this will likely increase the lead time based on increased demand for such instrumentation by operators. When Colorado finalized its LDAR requirements in Regulation 7, CDPHE allowed nearly 8 months for operators to begin LDAR monitoring using Approved Instrument Monitoring Method (AIMM). As with the storage vessel requirements under the original NSPS OOOO, the Alliance recommends revisions to the rule include reasonably sufficient implementation time. The Alliance suggests 9 to 12 months as a reasonable implementation timeframe.

xi. Recordkeeping

Proposed § 60.5420a(c)(15)(i) requires a fugitive emissions monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emission components at a compressor station, as required in § 60.5397a(a). As discussed below in our comments under **Section III(a)(xiii)**(Fugitive Emissions Monitoring Plan), there is no need for a site-specific plan; a corporate monitoring plan will suffice. In addition to the comments referenced above, consider the following examples of how a site-specific monitoring plan is superfluous and impractical:

- Corporate-wide monitoring plans must provide a procedure "for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained." 40 C.F.R. § 60.5397a(c)(7)(iii). Alliance members have found that maximum viewing distances vary from one individual camera operator to another. Therefore, the requirement to maintain a corporate-wide maximum viewing distance under the fugitive emission control program is unreasonable and lacks the flexibility operators need to conduct effective and efficient fugitive emission surveys.

- Each site-specific monitoring plan must identify "[d]eviations from your master plan." 40 C.F.R. § 60.5397a(d)(1). The Alliance assumes EPA's reference to "master plan" is the required corporate-wide monitoring plan in § 60.5397a(c). The Alliance submits that identifying all deviations from the corporate-wide monitoring plan in each site-specific monitoring plan is burdensome for operators. Well sites vary from site-to-site and from basin-to-basin. Dependent on development plans, operators could reasonably drill hundreds to thousands of wells in a basin over several years. Each well site will have hundreds to thousands of fugitive emission components. Deviations may be inevitable and pointing out all the variations would be extremely difficult, if not impossible. This requirement is also duplicative in nature because each site-specific monitoring plan will already contain adequate details of the survey for that site. Pointing out where those details conflict with the "master plan" is unnecessary.

- Site-specific monitoring plans must "include your defined walking path." The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences." 40 C.F.R. § 60.5397a(d)(3). Operators conducting OGI surveys must respond to a number of variables out in the field. These variables include weather, adverse monitoring conditions (*e.g.*, wind, sky condition) and interferences (*e.g.*, steam). Also, each operator representative may want to walk through a site differently. There are too many variables at each well site for operators to commit to a specific defined walking path for each survey.

The proposal would require photographs of each monitoring survey, along with the latitude and longitude of the well site or compressor station. See 40 C.F.R. §§ 60.5397a(k)(6)(ii), 60.5420a(c)(15)(ii)(F). This information is voluminous, superfluous, and provides no environmental benefit to the monitoring survey. In this regard, it is sufficient for operators to record only the date and location (the latitude and longitude) of the survey. The requested photograph recordkeeping provision, in particular, would require substantial data capacity to store and organize the photographs. Once stored, the photographs would need to be annotated with pertinent information, which would be a significant time burden. Considering the lack of environmental benefit associated with this recordkeeping exercise, we strongly oppose such a requirement in the proposed rule

Finally, 40 C.F.R. § 60.5420a(c)(15)(ii)(F) has a typographic error when referring to the number of subsequent paragraphs. As written, it states: "Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(1) through (2) of this section." There are four paragraphs under § 60.5420a(c)(15)(ii)(F), not two. If the proposed rule intends for all four paragraphs to apply, it should be revised accordingly.

xii. Reporting

The final reporting requirement should require only what is reasonable to collect and report based on an assessment of what information is necessary to demonstrate compliance (not necessarily, what information can possibly be collected). States like Colorado, Wyoming, and Utah are well ahead of EPA in this respect, and EPA should look to these reporting programs as models. The annual report should be a summary of monitoring surveys for the reporting period and not merely a collation and submission of all the recordkeeping requirements. Considering the voluminous amount of records, this would be a very onerous, time-consuming, and excessive task. Moreover, the rule does not justify how the proposed detailed and burdensome reporting requirements provide any environmental benefit. In particular, the report need not include items specified in proposed § 60.5420a(7) for each monitoring survey; these are items that should be kept as records, available for EPA review, but not included in the annual report.

Records for each monitoring survey must note "[a]ny deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan." 40 C.F.R. § 60.5397a(k)(5). Building from the Alliance's master plan statement in the above section, deviations are varied, many, and inevitable. Requiring operators to record every deviation from the site-specific monitoring plan at every survey is extremely burdensome. The Alliance submits the corporate-wide and site-specific monitoring plans should act as guidance for the operators and not represent inflexible requirements that the operator must consistently identify for each survey.

In line with what Colorado Regulation 7 requires in Section XVII.F.9 for annual LDAR reporting, we recommend that only the following elements be part of the annual report for fugitives:

1. The number of facilities inspected
2. The total number of inspections
3. The total number of leaks identified, broken out by component type
4. The total number of leaks repaired
5. The number of leaks on the delayed repair list as of the end of the reporting period

In addition, the proposed rule does not define the format of the report making it difficult to assess how the data should be collected, stored, and reviewed for quality. We recommend EPA keep the reporting as simple as possible.

Finally, 40 C.F.R. § 60.5420a(b)(1)(i) requires annual reports to include the address of the affected facility. Typically well sites and even compressor stations do not have physical addresses. In lieu of the address, we recommend that EPA use the latitude and longitude of the well site or compressor station for reporting purposes.

xiii. Fugitive Emissions Monitoring Plan

In 40 C.F.R. § 60.5397a(b)-(d), the proposed rule requires the development of both corporate and site-specific monitoring plans for fugitive emissions components. While we agree that a basic plan is a good idea, and many operators have their own plans, there is no need for a site-specific plan, particularly with the level of detail that EPA is proposing. Preparing such site-specific plans—particularly the requirements for creating a sitemap and defining walking paths which may need to change if a facility is modified—provide no added environmental value and would be excessively costly to develop and become cumbersome to maintain as a facility is modified in the future.

Developing a site-specific plan for fugitive emissions monitoring would be more burdensome than, for example, the development of a Spill Prevention, Control, and Countermeasure (SPCC) plan, <u>and</u> the fugitive emissions monitoring plan would require even more frequent revisions. Instead of overly burdensome, site-specific requirements, operators should be able to develop a field-wide plan, much as they do for an SPCC program. This will reduce administrative burdens that add no environmental benefit while providing a sufficient level of detail to determine that robust practices are in place.

Operators should be able to develop their own corporate plans as long as they contain the following basic elements:

1. Cost-effective frequency for conducting surveys.
2. Technique/method for determining fugitive emissions.
3. Procedures and timeframes for identifying and repairing leaks, including provisions for leaks that are unsafe to repair.
4. Procedures and timeframes for verifying leak repairs.
5. Recordkeeping and reporting requirements (as discussed above).

Anything beyond these requirements would be overly prescriptive. In addition, the rule should allow for requirements that are flexible enough for other instrumental methods, such as AVO, or for new monitoring methods that have not yet been developed.

Also, please note proposed 40 C.F.R. § 60.5397a(c) has a typographic error; as written, it states:

> Your corporate-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

However, there is no paragraph (8) under § 60.5397a(c).

b. Pneumatic Controllers

i. The effective date should be revised.

The effective date for installing pneumatic controllers at a location other than at a natural gas processing plant listed in proposed 40 C.F.R. § 60.5390a(c)(2) refers to a previous version of NSPS OOOO:

> Each pneumatic controller affected facility constructed, modified or reconstructed ***on or after October 15, 2013***, at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420a(c)(4)(iii).

Since this is a new requirement, this date should be corrected to reflect the applicability date of OOOOa, namely September 18, 2015.

ii. The proposed controls for pneumatic controllers should apply only to high-bleed devices with an emission rate greater than six standard cubic feet per hour (scfh)

It is our understanding that the definition of "affected facilities" only applies to high-bleed continuous pneumatic controllers. Per NSPS OOOO:

> Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

See 40 C.F.R. § 60.5390(c)(1). We request that EPA clarify in its final rule that intermittent-bleed and low-bleed devices are not "affected facilities" and will not be subject to these requirements for high-bleed devices.

iii. Operators should not be required to individually tag "affected facilities."[16]

For affected pneumatic controllers only—or, continuous high-bleed devices, as discussed above—operators should only be required to maintain a list of make, model, and serial number, rather than individual tags. A list of make, model, and serial number will achieve

[16] For the same reasons described in this section, this comment also applies to pneumatic pumps.

the same results desired by EPA, without presenting the unnecessary operational hurdles associated with individual tagging and recordkeeping. For example, tags can be damaged by weather and are unnecessarily difficult to maintain. Moreover, OOOOa appears to require operators to tag both facilities that constitute "affected facilities," and those that do not; which is unnecessary, confusing, and likely illegal. The proposal effectively requires tagging for components that fall under NSPS OOOO and for components that do not, which essentially requires operators to prove the negative. By tagging devices to prove they do not fall under the rule, EPA is imposing the same recordkeeping requirements on these devices even though they have been deemed to have low enough emissions to not be a cost-effective target for reductions. We believe such requirement exceeds EPA's legal authority and ignores the requirement to only promulgate rules which are determined to be cost-effective.

iv. The proposed CTGs for intermittent-bleed controllers are appropriate.

We support EPA's reasoning that intermittent-bleed controllers should be treated like low-bleed devices**.** A 2014 study conducted by Oklahoma Independent Producers Association (OIPA)[17] examined 205 producing wells and 680 pneumatic controllers. The study determined that on average, intermittent vent controllers emitted 0.40 scfh gas. By using the results as a point of reference, OIPA found that prior work:

- Underestimated the intermittent vent controller counts at the visited sites.
- Overestimated the intermittent vent controller emissions at the visited sites.
- Overestimated the continuous bleed controller counts at the visited sites.
- Overestimated the continuous bleed controller emissions at the visited sites, though previous methods give results of the same magnitude.

Therefore, we support the proposed rule's conclusion that intermittent-bleed controllers do not represent a significant source of emissions.

c. Pneumatic Pumps

i. There are feasibility concerns with pneumatic pump requirements.

We support the proposed rule language requiring no more than 95 percent control for pneumatic pumps. Higher levels of control are not technically feasible or cost effective. We understand EPA agrees with this position. For example, EPA's detailed cost analysis for 40 C.F.R. § 63, Subpart HHHH correctly recognizes control efficiency above 95 percent may not be technically feasible. See *Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories,* Memorandum to Greg Nizich, Bruce Moore, EPA, at 2 (April 17, 2012)("Test data indicates that levels of control above 95 percent have not been shown to be reliably

[17] *Pneumatic Controller Emissions from a Sample of 172 Production Facilities,* Oklahoma Independent Producers Association, November 2014.

achieved in the field. Based on this analysis, we conclude that 98 percent control [is] neither technologically nor economically feasible at this time.")

There are a number of compelling technical, economic, and, environmental reasons not to increase control efficiency requirements for pneumatic pumps:

- Not all pneumatic pumps can be effectively routed to an existing control device. Take, for example, natural-gas fired piston pumps (i.e. pneumatic methanol injection pumps) located at the wellhead. Pneumatic methanol pumps at the wellhead are far from where existing combustors are typically located at a site (e.g. at the production equipment and /or storage vessels). As a result, there will be insufficient pressure from the exhaust of the pneumatic pumps to be routed back to the combustor. Operators will not be able to control emissions by 95 percent from these pumps with existing controls. Accordingly, operators will have to consider converting pneumatic pumps to air-driven, electrically-powered or solar pump alternatives. Many oil and gas fields do not have access to grid electricity and it is extremely costly to install. If grid electricity is not already available, the use of air-driven or electrically-powered pumps is not an option without costly generators and additional emissions to provide onsite electricity generation. Solar pumps can also be costly. Solar pumps cost around $3,700 per pump and require approximately $1,000 in maintenance/service costs every three years. Solar pumps are also inherently unreliable because the sun does not shine all the time. The Alliance requests that pneumatic methanol pumps located at the wellhead be exempt from the requirement to control VOC and methane emissions by 95 percent from an existing combustion control device.

- A capture rate of higher than 95 percent from a pneumatic pump on a vapor recovery unit would require compression of extremely low volumes of low-pressure gas, in order to overcome back pressure into the pump from the vapor recovery system. In addition to adding substantial cost, compressing these low volumes of gas will generate other emissions that would almost certainly negate any environmental benefit from their capture.

- During upset events, back pressure from a control system on a pneumatic pump would pose a safety hazard. Pressure buildup on the pump could rupture a diaphragm and create a much larger human and environmental health hazard than the emissions being targeted for capture. Capture requirements on pneumatic pumps may force companies away from them entirely. However, alternatives like instrument air and solar pumps are not a realistic or feasible (technically or economically) alternative in many cases. Instead, companies will be forced to install redundant back-up pump systems, which will add a significant expense that EPA has not accounted for in its cost analysis.

- Pneumatic pumps do not present a major source of emissions, yet the rule would require each unit to be handled like a much larger piece of equipment. The emissions and cost data do not support this approach, and we strongly urge EPA to reconsider requiring controls for such a small source. This is particularly problematic in the case of diaphragm pneumatic pumps, which are only used intermittently. These pumps, along with methanol pumps and heat trace pumps used only during winter months, have very minor emissions. Moreover, given their intermittent status, it appears EPA never intended to regulate diaphragm pneumatic pumps, and the Alliance seeks clarification regarding its regulation of such intermittent equipment.

- If a pump is emitting less than 6 scfh it should be exempted from these standards. Requiring emission control on such a small source is both impractical for the technical reasons stated above and offers minimal environmental benefit. Similarly, limited use pumps like transfer pumps and sump pumps should be exempted.

ii. Electrification is not always a viable option

The proposed rule requests comment on the availability of constant, reliable electrical power at oil and natural gas production facilities. *See* 80 Fed. Reg. at 56,625. Electrical "grid" power in the field is uncommon, but ultimately extremely variable from basin-to-basin. Take, for example, one member company's feedback on the percentage of development with electricity by state: 50 percent in North Dakota, 0 percent in Louisiana, 0 percent in Wyoming and 30 percent in Utah. Further, the costs to electrify a field are substantial. One member company reports a $15-20 million cost range for field-wide distribution in WY. A company with operations in ND reported an average cost of $320,000 per mile of 25 kV distribution line.

d. Definition of "Natural Gas Processing Plant"

In the proposed rule, EPA defines a natural gas processing plant as:

> Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

See 40 C.F.R. § 60.5430a. In the context of this rule, the definition is overbroad, and would impact far too many facilities that could not reasonably be construed as a "natural gas processing plant." This definition would pull in numerous facilities that have absolutely nothing to do with "natural gas processing" based on industry definition and custom. For example, operators are often required to extract NGL from gas prior to delivery to a sales pipeline, in order to meet existing pipeline specifications. The extraction process may require use of a JT process, refrigeration, or a combination of the two. JT skids often are co-located with other similar equipment including glycol dehydrators and compressors. In this case, operators likely would be subject to requirements for "natural gas processing plants" due to the mere presence of a JT skid or a refrigeration unit at a compressor station or tank battery. We do not believe this was EPA's intention in drafting this definition and question whether such a broad definition would truly be cost-effective.

This overbroad definition would also disincentivize technological advancements and potentially create more environmental harm. For example, mobile recovery units (MRUs) are being used more frequently at wellsites in North Dakota to extract natural gas liquids (NGLs) from produced gas that cannot be delivered into the gathering system. These MRUs aid in compliance with the NDIC flaring restrictions, and prevent the unnecessary waste of natural resources. This is a good example of both: (1) potential unintended consequences posed by such a broad definition; and (2) why a one-sized-fits-all approach on many of these issues does not make sense or allow for the flexibility needed to address specific environmental issues that may differ in different areas of the country. Furthermore, application of this overly broad definition in this rule carries significant, and we believe unintended, consequences for the potential applicability of upstream E&P sites to other programs such as the Risk Management Plan (RMP) program.

e. Compressors

i. EPA should revise § 60.5385(a) to require rod packing maintenance rather than rod packing replacement.

Currently, proposed § 60.5385(a) states: "You must replace the reciprocating compressor rod packing before the compressor has operated 26,000 hour." For reciprocating compressors, the Alliance suggests "replace" should be changed to "inspect and maintain." In this respect, we support America's Natural Gas Alliance's (ANGA) comments and position in its 2012 NSPS OOOO comments on this issue[18]:

> We recommend the final rule refer to rod packing maintenance rather than rod packing replacement. The rod packing components associated with restoring performance may not all need to be discarded, and some components may not need to be replaced. EPA's proposed terminology may inadvertently preclude operators from using proven maintenance practices to address rod packing leakage.

The proposed rule should also clarify that a control system using wet seals with a closed vent system or a dry seal system is an acceptable control strategy. This was permissible under NSPS OOOO. The same rationale still applies and the two rules should be consistent.

[18] *Comments on Proposed NSPS OOOO for Oil and Natural Gas Sector*, ANGA, 2012.

ii. Staggered annual reporting for compressors is overly burdensome on operators.

The Alliance proposes the rule set an annual reporting date for all applicable sources subject to NSPS OOOO and OOOOa (e.g., September 30th every year, or within 90 days of the end of the year, etc.). Based on our members' past experience complying with NSPS OOOO, annual reporting is very burdensome; especially so for operators with many compressors, each with varying initial startup dates, requiring individual tracking and reporting under the proposed rule.

f. Storage Vessels

i. EPA storage vessel standards in OOOOa are not technically achievable, incentivize unsafe operations, and result in unnecessary economic waste.

The proposed rule requires operators to route all gases to a closed vent system. 40 C.F.R. § 60.5411a(c). The upstream oil and natural gas production industry faces a dynamic production stream that varies greatly in terms of composition and volumes of produced fluids. This variability requires the use of systems like thief hatches and other pressure relief devices (PRDs), which allow for atmospheric storage vessels to operate safely under a variety of operational conditions. The proposed rule improperly treats thief hatches and PRDs like sources of fugitive emissions, rather than as parts of an atmospheric system where safety and other operational concerns demand occasional venting during normal operations. It is imperative for the safety and continued operation of this industry that the final rule recognize that thief hatches and PRDs are pieces of equipment that must be permitted to vent occasionally during normal operations, much like pneumatic controllers which are designed to vent. This would include necessary changes to the definition and concept of closed vent systems. As currently drafted, however, the final rule is not workable in this key respect.

The proposed rule solicits comment on requiring professional engineer (PE) certification of storage tank vapor control systems. The Alliance strongly opposes this requirement. If promulgated, this portion of the rule could force a design analysis, requiring facility re-design at thousands of facilities across the country. The proposed rule does not contemplate the costs associated with the impacts of this requirement. This potential requirement is infeasible for several reasons:

- System design is typically conducted in-house prior to production. At that point, the production volumes, composition, and many other factors are unknown. As a result, it would be impossible to certify the effectiveness of a design prior to construction.

- Atmospheric storage vessels are designed to have some loss of emissions through normal operating design (see comment above regarding impracticability of closed vent systems). Given this, it would be unreasonable to expect a PE to certify that all emissions are being routed to a control device.

- Operators do not typically use third-party contractors to design their facilities. Retaining a third-party simply for certification is impractical for the reasons stated above, and would add significant cost and delay to facility design.

We also have concerns over the next generation recordkeeping and reporting requirements proposed in this rule; these proposals would exceed EPA's authority, pose a potential public safety risk, and add significant reporting costs without providing any additional environmental benefit. In particular, EPA does not have the authority to require companies to place certain information on their corporate websites, including information that is not otherwise required by law but may be desired by certain members of the public.

While some Alliance members may support some elements of EPA's next generation compliance program, that program does not grant EPA unfettered authority to promulgate regulations that could force the entire industry to change the way in which it designs and operates its facilities or reports information—particularly where the rule has neither demonstrated the need to do so, nor discussed the environmental benefits to be obtained or the costs to be incurred. The next generation program must be reasonable with respect to its requirements and its consequences. On balance, we do not believe requiring third party certification of design is reasonable.

ii. EPA should exempt all produced water storage tanks from OOOOa.

As noted in the preamble to the proposed rule, large water storage tanks are exempted from the proposed NSPS due to their low overall VOC emissions. 80 Fed. Reg. at 56,648. The Alliance supports this exemption; but also encourages an expansion of this exemption to all produced water storage tanks. Unintended coverage of small tanks under OOOOa would discourage water recycling. If large-throughput tanks can safely be exempted, it stands to reason that much smaller tanks—imposing even less emissions—should also be exempted.

iii. There are notable inconsistencies between OOOOa and the corresponding CTGs for storage tanks.

Under OOOOa, EPA proposes quarterly testing of emissions using EPA Method 22 for manufacturer-tested combustion control devices for one hour. For non-manufacturer-tested devices, OOOOa requires monthly testing for 15 minutes using Method 22. However, in the proposed CTGs, the rule imposes different testing protocols, instead, requiring monthly testing using Method 22 for manufacturer-tested devices. We recommend that the quarterly testing of emissions be consistent and that for both Subpart OOOOa and CTGs, operators should have a choice between either monthly testing for 15 minutes or quarterly testing for one hour, regardless of whether the flare is manufacturer-tested.

g. Oil Well Completions

As the proposed rule is written, some operators may be unable to comply with the oil well completion requirements. For example, in fields with small volumes of associated gas like the Permian Basin, operators may be unable to run a three-phase separator. Fields that produce heavier crudes—like in Utah's Uinta Basin—face similar logistical challenges running a three-phase separator.

Furthermore, we have concerns about redundancy with existing state regulations. The proposed rule notes the regulations are modeled on state rules in Wyoming and Colorado. 80 Fed Reg. at 56,628. The final rule should be revised so that operators subject to comparable state rules regarding oil well completions are not also required to comply with the federal NSPS oil well completions provisions. If operators have to comply with both federal and state rules that address the same issue, it puts these operators at an economic disadvantage compared to states that do not have such duplicative requirements. The following addresses several of the more problematic technical issues and questions with respect to the oil well completions proposal.

i. EPA's economic analysis of oil well completions is flawed.

RECs, where feasible, are considered standard industry practice. The proposed rule recognizes this fact in the proposed OOOOa rulemaking and in its technical white paper on the subject. *See* 80 Fed. Reg. at 56,632 (Noting that "[s]everal public and peer reviewer comments on the white paper noted that these technologies are currently in regular use by industry to control oil well completion and recompletion.") Given RECs are already standard industry practice, this proposed rule only serves to remove operational flexibility and add significant recordkeeping and recording burden without any additional environmental benefit. As such, the Alliance believes this provision of the proposed rule is unnecessary.

Even if EPA somehow is able to justify the additional emissions benefits by making standard industry practice a regulatory requirement, the rule should be amended to avoid potentially overlapping requirements between NSPS OOOO and OOOOa. As written, the rule appears to set up different compliance periods for both oil and natural gas well completions. These should be consistent. In addition, we recommend the proposed rule offer flexibility to operators on the compliance reporting schedule, rather than dictate the timeline in the final rule.

The cost analysis for REC requirements is incomplete or incorrect. For example, in its proposed rule, EPA's analysis of REC costs assumes a range of $700-$6,500, lasting for an average of three days. EPA assumes an oil well REC will cost on average $13,586, taking into account gas savings. 80 Fed. Reg. at 56,629. EPA's numerous assumptions to reach this conclusion are flawed and ignore actual operator experience. In our members' experience, actual costs will be much higher.

We also question the rule's analysis of the oil well completion emission benefits. In its white paper analysis of oil well completions, EPA states that methane is 46.732 percent of the volume of gas produced during a well completion. [19] Based on surveys of operators, this number is highly inaccurate (*see* table below). Our analysis suggests 40 to 80 percent is a more representative range for methane, with many basins producing gas that is over 60 percent methane. It also is important to note the remaining gas volume is not entirely VOCs. Gases like ethane, carbon dioxide, and nitrogen can make up significant volumes of produced gas. In many cases, VOC emissions are likely 10 to 30 percent of the total volume. These differences in gas composition will dramatically affect EPA's cost and benefit analysis. EPA's flawed assumptions about the value of natural gas prices and therefore the value of recovered product will be compounded by the inaccurate assumptions about gas compositions. The end result is an inflated benefit calculation that assumes much higher recovery rates of higher-value VOCs than methane.

Oil Well Completion Data

	DJ Basin	**Williston Basin**	**Powder River Basin**	**Permian Basin**
Days to complete (flowback)	2 to 7	2 to 9	21 to 28	3 to 5
Additional green completion cost per day ($/day)	$2,000-$7,200	$3,500-$10,800	$8,400	$4,500
Average volume of gas produced during completion (MCF/day)	1,500-3,000 MCF	300-2,500 MCF	100-1,500 MCF	500-1000
Average percent gas currently flared during completion	50-80 percent	50-80 percent	90-100 percent	90-95 percent
Average percent gas currently sold during completion	20-50 percent	20-50 percent	0-10 percent	0 percent
Average percent gas currently vented during completion*	< 1 percent	< 1 percent	< 1 percent	5-10 percent
Methane gas composition percent	40-80 percent	50-70 percent	70-80 percent	75 percent
VOC gas composition percent**	10-30 percent	10-30 percent	10-20 percent	12 percent

Also of note is the high variability of well flowback times and costs per green completion. A one-size-fits-all cost analysis will almost certainly fail to capture the highly variable nature of well completion operations. Small operators also tend to be on the high end of completion costs, and typically conduct completions less frequently. Generally, small operators lack the purchasing power to get the discounted prices service companies offer to larger operators. Therefore a one-size-fits-all cost estimate would likely not adequately represent the cost burden faced by small operators. In order to demonstrate the REC

[19] *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production,* at 13, EPA, April 2014.

requirements being proposed would be cost-effective, the final rule's economic analysis must consider these points.

ii. There are notable implementation concerns.

The oil and natural gas industry is constantly looking for ways to maximize efficiency and product recovery—including in the completions process. However, the rule must recognize the numerous instances where RECs may be infeasible for technical reasons or for circumstances beyond an operator's control. For instance, low pressure oil wells may produce associated gas; but the pressure differentials between a gas gathering system and the well may require substantial compression in order to move gas from the wellhead separator into the gathering system. In some instances, overcoming this pressure differential may be too costly and impractical from an economic standpoint. And the emissions from the required compression might actually negate any environmental benefit associated with gas capture.

The gas-gathering infrastructure in the West (particularly on federal lands) is already under immense stress, and the proposed regulations would greatly increase the burdens on operators and gas gathering companies. The process to permit gathering line right-of-ways (ROWs) on federal lands is often a frustrating and time-consuming process, and it can sometimes take years before an operator receives construction approval. In these situations, operators are left with no choice but to flare associated gas from production. EPA should work with its federal agency partners to provide operators with a reliable, predictable, *and timely* permitting process. This would offer economic and environmental benefits to operators as well as the public.

Where the proposed rule solicits comment on criteria that could help clarify availability of gathering lines (80 Fed Reg. at 56,634), we suggest one criterion that could be used to define capacity to accept additional throughput is hydraulic modeling results. Hydraulic modeling of the gas gathering system and of new connections is typically done in advance of oil well/associated gas completions. If the hydraulic modeling results indicate that less the full amount of estimated gas production at flowback can be accepted into the gathering pipelines, then a combination of recovery and combustion should be allowed.

The proposed rule also solicits comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery. 80 Fed Reg. at 56,634. The Alliance contends that distance to gathering lines alone is not a valid criterion. ROW delays impact short and long distance connections equally; there may not be gathering pipe available during flowback due to ROW delays. Also distance does not consider whether there is capacity to accept additional throughput. The distance to a gathering pipeline may be short, but there may be no capacity to accept additional throughput. Recovering gas in this situation is technically infeasible.

The following provides additional details of the process required to obtain approval for pipeline construction on property subject to National Environmental Policy Act (NEPA) jurisdiction, which includes the Fort Berthold Indian Reservation. The timeline is based on an aggregation of actual projects.

1. Obtain permission to survey (PTS) from landowners and submit to BIA (Bureau of Indian Affairs) New Town office for approval. ***(4 weeks)***
    a. Responsible party: operator's land agent

2. "Soft stake" the pipeline centerline after PTS has been granted by BIA (surveying company/engineers). ***(1 week)***
    a. Responsible party: surveying company and/or contracted engineer

3. Schedule Environmental Assessment (EA) onsite. ***(1 week)***
    a. A representative from the BIA-New Town office must be present.
    b. Consultants conduct natural and cultural surveys.

4. Prepare final plans. ***(3 weeks)***
    a. Responsible party: surveying company and/or contracted engineer

5. Prepare and send scoping letter for approved pipeline (if applicable, for trunk lines only, lateral lines to well locations will not require scoping). ***(4 weeks)***
    a. Responsible party: consultants
    b. The EA cannot be submitted until the end of the 30-day comment period

6. Schedule ROW onsite with the BIA-New Town office. ***(1 week)***
    a. A representative from the BIA New Town office must be present
    b. Responsible party; Operator

7. Prepare EA and cultural reports; from initial surveys conducted in step 3. ***(12 weeks)***
    a. Responsible party: consultants
    b. Submit cultural reports to the BIA before the EA is submitted. Unless the THPO office clears the report sooner, there is a 30-day waiting period before the BIA in Aberdeen will review the EA

8. If habitat for a listed endangered/threatened species is present, an informal consultation with the US Fish and Wildlife Service (USFWS) is required. Project must receive concurrence from USFWS. ***(8 weeks or longer)***

9. Submittal of EA to BIA Aberdeen office and Finding of No Significant Impact (FONSI) is reached. ***(4 weeks)***
    a. Responsible party: consultants

   b. There is a 30-day notice period after the FONSI is issued

10. Pipeline Company obtains landowner signatures agreeing to terms and payment. These signatures are then filed in the ROW application that is submitted to the BIA New Town office for approval. ***(4 weeks)***
    a. Responsible party: Pipeline company land agents

11. Construction operations can begin only after the BIA issues a Notice to Proceed and ROW grant. ***(5 weeks)***

The above-described times for completion of each stage will vary depending on: BIA onsite schedule, completeness of supplementary information, results of resource surveys, results of onsites, completeness of application packages, public response to projects, weather conditions, and, of course, securing proper consents from all necessary landowners.

In other instances, particularly in areas like North Dakota, gas gathering and processing infrastructure exists, but lacks capacity. This is particularly true where new development has occurred without pre-existing infrastructure. Where it is practical, producers will nearly always develop in areas near gas gathering systems. This allows maximum economic and environmental benefits. But it is not always practical to develop near this infrastructure—especially in very remote areas (such as certain parts of North Dakota). Producers do not always have control over how gas gathering infrastructure is used. For example, in some cases, midstream companies may curtail the capacity made available for an operator's associated gas or other constraints. In others, lease terms and other constraints require the resource to be developed on a certain timeline despite dedicated infrastructure. The REC rules must account for these inherent uncertainties and difficulties; or the rule risks shutting down significant portions of this industry, which is already unduly strained by low commodity prices. Such consequences are likely to be borne disproportionately by smaller producers.

Further complicating matters, some wells may come online with a high initial production (IP) rate. In these instances, the large volumes of associated gas produced may overwhelm limited gas supply capacity. Operators are left with little choice but to flare that associated gas or risk damage to the reservoir of a highly productive oil well by choking it back. That could have significant economic consequences for operators as well as mineral owners, including the federal government. The final rule must consider these consequences in its economic analysis of RECs. We recommend the final rule defers to operator knowledge to determine when green completions are feasible. Operator expertise and field knowledge will be sufficient to determine whether there is enough gas to operate a temporary separator.

Industry also lacks the necessary equipment to roll out REC requirements nationwide in such a short implementation window. EPA should create a compliance phase-in period of at least 6 months. This phase-in timeline will give operators the flexibility to meet new requirements for any RECs involving specialized equipment. If there is no phase-in period, the REC requirements will be particularly burdensome for small operators. The lack of supply will drive up REC costs, which will not be absorbed as quickly by smaller entities. And these small entities will almost certainly lack the purchasing power of larger operators, thereby making it difficult to obtain the needed equipment before the compliance period begins.

iii. The Alliance requests clarification on completion flowback.

We request clarification from EPA on completion flowback. In some fields, operators will flow completion fluids directly into the production tank batteries. In these instances, how will the proposed rule apply the REC requirements?

h. Control Devices – CTGs

EPA should clarify and define what it means by "control device," as this term is used in more than one context. The following text from the CTGs illustrates the inconsistencies:

- Recommendations for *Control Device* Operation and Monitoring: Enclosed Combustion Devices: "VRUs and flow lines that "route emissions to a process" would be considered part of the process and would not be considered *control devices* that are subject to standards, but the closed vent design, operation and monitoring requirements specified in sections 5.5.3 and 5.5.4 would apply."

- Appendix E-3 (d)(4): "Each combustion *control device* (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (i) through (iv) of this section. "

- 6.0 Pneumatic Controllers: "The oil and natural gas industry uses a variety of process *control devices* to operate valves that regulate pressure, flow, temperature, and liquid levels."

- 6.3.1.3: Electrically Powered Systems in Place of Bleed Devices: "Mechanical controls have been widely used in the oil and natural gas industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical *control device* being a liquid-level float to the drain valve position with…"

- 6.3.1.2: "The size of the compressor depends on the size of the facility, the number of *control devices* operated by the system, and the typical bleed rates of these devices."

(emphasis added). Not all of these are control devices, and the multiple references will cause confusion. EPA could resolve this issue by incorporating the definition of control device from 40 C.F.R. 63, Subpart HHHH (National Emission Standards for Hazardous Air Pollutants (NESHAP)):

> *Control device* means any equipment used for recovering or oxidizing HAP or [VOC] vapors. Such equipment includes, but is not limited to, absorbers, carbon absorbers, condensers, incinerators, boilers, flares, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of an enclosed combustion device), returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be a control device or closed-vent system.

See 40 C.F.R. § 63.761. This definition adds consistency across oil and gas regulatory programs. It also recognizes that "routing to a process" is a beneficial use or reuse of exhaust gases and vapors not an emissions control.

In addition, since EPA uses the term "control device" in several contexts within the CTGs, we recommend EPA amend or supplement the definition in NESHAP, Subpart HHH. For example, in NESHAP, Subpart HHH, "returning to process" is exempt from the definition of control device and exempt from closed vent system requirements. This is inconsistent with the definition proposed here. Many sites that will be covered by an existing source RACT rule may also be required to comply with Subpart HHH. Failure to consistently define this term across a RACT rule—governed by the CTGs and Subpart HHHH—will setup a compliance conflict for the operator.

In addition to the multiple applications of the word "control device," EPA contradicts the definition of "routed to a process." This inconsistency treats heaters and boilers as equivalent to flares, combustors, and thermal oxidizers. The text states:

> *Routed to a process or route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

i. **Control Devices – OOOOa**

EPA should clarify and define what it means by "control device," as this term is used in more than one context. More importantly, EPA has confused actual control devices with process equipment. The following text from the NSPS OOOO and OOOOa illustrate the issue:

- 40 C.F.R. § 60.5412a(d)(1)(iv): "Each combustion <u>*control device*</u> *e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section."

- 40 C.F.R. § 60.5412(d)(1)(iv)(D) "If a boiler or process heater is used as the <u>*control device*</u>, then you must introduce the vent stream into the flame zone of the boiler or process heater."

A boiler or heater is not a control device, but rather each is designed as process equipment. If exhaust gas from a pneumatic pump or other source can be routed to a boiler or heater, this meets the definition of "routed to a process" along with a VRU. To be introduced into the flame zone, exhaust gas can be tied into the fuel system and becomes fuel gas for the boiler or heater.

Also, boilers and process heaters, while frequently found on many oil and gas sites with or without another type of emissions control device, cannot always be used to recycle pneumatic exhaust gas. The design and operation of a process heater or boiler may not be compatible with the operation of the pneumatic pump or other source of gas to be recycled. However, as proposed, EPA seems to be mandating that a process heater or boiler be used since it is a "control device" in the proposal without regard to design and operational compatibility. This equipment is designed to facilitate the process not control emissions.

Compounding the confusion between true control devices and process equipment, the proposal would treat some process equipment (*e.g.*, treats heaters and boilers where emissions are recycled) as equivalent to flares, combustors, and thermal oxidizers (*i.e.*, control devices). This is because of the definition of "routed to a process or route to a process." The text states:

> *Routed to a process or route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

The resolution to this issue is to incorporate the definition of control device from 40 C.F.R. § 63, Subpart HHHH with the added term, "or natural gas"

> *Control device* means any equipment used for recovering or oxidizing HAP or volatile organic compound (VOC) vapors, <u>or natural gas</u>. Such equipment includes,

> but is not limited to, absorbers, carbon absorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of an enclosed combustion device), returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be a control device or closed-vent system.

See 40 C.F.R. § 63.761. This definition adds consistency across oil and gas regulatory programs and recognizes routing to a process is not emissions control but rather a beneficial use or reuse of exhaust gases and vapors, and that should be encouraged. For NSPS OOOO and OOOOa, routing exhaust pneumatic or compressor gas, if feasible, makes these streams part of the fuel gas system.

The rule also needs to recognize that many sites that will be covered by NSPS OOOO and OOOOa will also be subject to Subpart HHH. Not having consistent definitions and exemptions across NSPS and NESHAP rules will setup a compliance conflict for the operator. EPA should also note that in Subpart HHH, returning to process is not only exempt as a control device but also exempt from closed vent system requirements. We believe this is the correct approach.

IV. Comments on the CTGs

a. Executive Summary

When finalized, EPA intends that the CTGs will provide state, local, and tribal air agencies with information to assist them in determining reasonably available control technology (RACT) for volatile organic compound (VOC) emissions from oil and natural gas sources. As described below, however, the CTG proposal suffers from significant flaws that must be addressed before the CTGs become final. As a threshold matter, it is critical that the CTGs remain "guidelines" and not mandatory, enforceable federal RACT requirements. Especially given that many states, like Colorado, already have RACT requirements applicable to sources in this sector included in their State Implementation Plans (SIPs).

b. The Alliance's Position on the CTGs

i. General Comments on CTGs

The CTGs recommend EPA-approved requirements that states must impose on oil and gas exploration and production companies in areas of non-attainment; yet such recommendations have not been appropriately vetted, analyzed, and do not reflect the operational nuances or realities (i.e., new and modified sources are much different from existing sources) inherent in oil and gas production. Indeed, the complexity of site-specific operations, often impacted by the uniqueness of geography and formation, are best served by an adaptive approach, rather than a prescriptive one. Oil and gas exploration and production companies rely on flexibility in management decisions and styles, rather than a one-size-fits-all requirement with respect to control requirements and technology.

Without confirmation that the CTGs will remain guidelines—and not effectively serve as enforceable standards or work practices—operational nuance and complexity cannot be protected.

ii. Specific Comments on CTGs

The Alliance has reviewed the CTGs and has organized its comments based on specific sections, as noted by the headings below.

- Section 1.0 (Introduction):

EPA has not explained why states are only afforded two years to submit SIP revisions in response to finalization of the draft CTGs. As with other SIP planning, and in light of currently heavy burdens on state air quality planning staff, we believe EPA should afford at least three years to develop proposed SIP revisions through state rulemaking processes.

- Section 3.1 (Overview of the Oil and Natural Gas Industry):

Production components are identified as including wells and related casing head, tubing head and so-called Christmas Tree piping (*i.e.*, "well head piping"), as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices, and dehydrators. It is important to distinguish sites with just well heads well head/piping and no separators or storage vessels as sources of emissions. EPA did this in the proposed OOOOa rules and should be consistent in the CTGs. We recommend EPA do so in the final CTGs for numerous reasons (access etc.), including the fact the costs and benefits of including such production facilities in the CTG controls do not warrant their inclusion and likely are very different than has been estimated by EPA.

- Section 3.2 (Sources Selected for RACT Recommendations):

The draft CTGs indicate that sources in the onshore production and processing segments were selected for coverage by the CTGs' because they "are significant sources of VOC emissions." Recommendations are presented where the application of controls is judged to be reasonable, "given the availability of demonstrated control technologies, emission reductions that can be achieved and the cost of control." A significant concern and apparent gap in EPA's draft guidelines concerns the application of recommended RACT controls to production of dry gas. Once again, not all facilities in this segment are equal; and, in fact, there are vast discrepancies across the segment due to numerous factors, including geology. It is critical that the CTGs provide sufficient flexibility to tailor the controls to the given situation.

In addition, the draft guidelines were based on methane data, not VOC emissions data. VOC emission reductions were estimated secondarily based on EPA's 2011 Natural Gas Compositional Analysis Memorandum, Docket ID No. EPA-HQ-OAR-2010-0505-0084. Because certain dry gas production activities involve very low concentrations of VOCs, the VOC reduction benefits from such production activities and sources are significantly lower than estimated by EPA.

- Table 3-1 (Summary of the Oil and Natural Gas Industry Emission Sources and Recommended RACT):

This table contains a summary of the RACT recommended for specific sources in the draft guidelines. In a number of places, the recommendation is for zero natural gas emissions or a bleed rate of zero scf/hr of natural gas. These references should be corrected, where applicable, to acknowledge that certain sources/devices, such as low-bleed pneumatic devices with a continuous bleed rate of less than 6 scf/hr, have fugitive emissions because they are threaded components in natural gas service, and there is no basis for assuming that they do not have some *de minimis* level of fugitive emissions below the level defined in other applicable regulations (*e.g.*, NSPS OOOO) as constituting a "leak." In short, the RACT recommendations must be amended to acknowledge equipment, like low-bleed pneumatic devices, must be allowed some level of fugitive emissions or serious safety and operational issues will arise.

- Sections 4.0 and 4.1 (Storage Vessels and Applicability, respectively):

The Alliance appreciates the exclusion of mobile and temporary tanks such as "frac tanks" from the recommend guidelines for RACT control of storage vessels, as well as excepting process vessels and pressure vessels; however, the qualification that pressure vessels "are designed to operate . . . without emissions to the atmosphere" is incorrect. Pressure vessels also have some small potential for fugitive emissions at valves, which are threaded components subject to leak detection and repair requirements for detecting leaks. Accordingly, even in normal operation, pressure vessels emit small amounts of fugitives to the atmosphere. For safety and operational reasons, this must be acknowledged in the final CTGs.

Also, the applicability of the storage vessel guidelines to produced water tanks is not warranted, especially in the case of coalbed methane (CBM) produced water and water from dry gas wells that is very low in VOCs. EPA should make wells below a *de minimis* threshold of emissions, such as 6 tons per year, exempt from the requirement to control emissions unless emission control devices capable of also controlling vapors from produced water tanks were already required and in use at a particular affected facility. Given the low VOC emissions in such produced water tanks, there is little if any environmental benefit associated with extending the storage vessel guidelines to these units. And without such an exception, the benefits and costs of VOC control are heavily skewed and not adequately justified for inclusion in the RACT guidelines by EPA.

- Section 4.2.2.2 (Representative Storage Vessel Baseline Emissions):

The data relied upon in estimating Representative Storage Vessel Baseline Emissions are of concern. Specifically, EPA has relied on two VOC emissions throughput estimates that are derived from a very limited and rather dated sampling of approximately 100 storage vessels in 2000. *See* CTGs, at fn. 12. Some types of oil are quite heavy and less volatile, and the factors proposed by EPA will significantly overestimate VOC emissions from such oil storage vessels as a result. Additionally, there does not appear to be a separate emission factor for produced water tanks, or a distinction for when produced water would be treated like oil or condensate for purposes of RACT storage vessel controls applicability.

- Section 4.3.1 (Available VOC Emission Control Options):

The two options identified for storage vessel emissions control are use of a vapor recovery unit (VRU), or use of a combustor. A third option commonly used and not evaluated is the use of a VRU and a combustor, where the combustor is relied upon to control emissions when the VRU is not operating (*i.e.*, combustor backup of a VRU). Again, the CTGs should remain flexible and also take care to consider all possible operating and control scenarios, including this third option for storage vessel emissions control.

- Section 4.3.1.1 (Routing Emissions to a Process via a VRU):

EPA proposes 95 percent control of storage vessel emissions by a VRU, but does not cite to data indicating that 95 percent control is achievable. EPA does cite to other existing regulatory requirements for a 98 percent control effectiveness, but it is not clear that these requirements take into account VRU downtime for maintenance, etc. or indicate the control effectiveness of the device only when in normal operation. If the latter, then compliance with this requirement is only possible if production is shut-in during VRU downtime. Not only is this not practicable or reasonable, EPA did not account for the significant cost to operators of shutting-in production.

- Table 4-3 (Total Capital Investment and Total Annual Costs of a VRU System):

EPA assumes a 15-year equipment life for VRUs without any data in support. EPA cites to a Colorado Economic Impact Analysis from 2013 that was subject to significant adverse comment from industry, including regarding the assumed 15-year useful life of such equipment. EPA should gather additional data on VRU useful life in actual operation and also evaluate the costs of VRU control assuming a more conservative 10-year useful life to indicate the sensitivity of EPA's estimate to this variable.

- Section 4.3.1.2 (Routing Emissions to a Combustion Device):

Please refer back to the comment above regarding Section 4.3.1. In addition, the use of a VRU and a combustor, where the combustor is relied upon to control emissions when the VRU is not operating (*i.e.*, combustor backup of a VRU) is very common, so as to avoid violations or the need to shut-in production during periods of VRU down time. EPA should evaluate this combined cost with and without gas savings, and also with an assumed VRU equipment life of 10 years.

- Section 4.4 (Recommended RACT Level of Control):

The Alliance does not disagree with EPA's recommendation of a 95 percent control requirement for recommended RACT control of storage vessel emissions through use of a combustor, subject to its other comments herein, but again notes that VRU control of emissions at a 95 percent level cannot be achieved during periods of VRU downtime without use of a combustor as backup emissions control, thereby significantly increasing the costs of control. If 95 percent control of emissions by VRUs (without a combustor backup) is only achievable with longer averaging periods, but operators will be found in violation if 95 percent control is not achieved at all times, then EPA's analysis is flawed and must be corrected.

Also, EPA arrives at the same level of control applicability for existing sources in the proposed draft CTGs as it did for new facilities in NSPS OOOO. This conclusion by EPA is very troubling to the Alliance by virtue of the very different economics at issue for the operator of an existing well and associated storage vessel(s), as opposed to a new or modified well subject to NSPS OOOO. Basic economics in this segment holds that the marginal economic value of each well declines—sometimes precipitously—over time. That is, production decline over time causes lease operating expenses to increase substantially over time relative to the production value of the well. Eventually all wells approach "marginal" status because of this, making continued operation an economically tenuous prospect. In many plays throughout the country, marginally economic wells can make up the large majority of active wells. For these facilities, which are the target of the CTGs, it does not take much additional expense to force the operator to shut-in because the well is no longer economical. In light of these basic economic realities, the fact that EPA's cost analysis supports the same level of control applicability for the draft CTGs as it did for new and modified sources under NSPS OOOO, on its face, is dubious. And this is saying nothing of the fact the same production decline that causes wells to become marginal, also means there are less VOC or other emissions to be captured.

Finally, there is no cost or effectiveness analysis for storage vessel controls applied to produced water tanks, which emit significantly less VOCs on average than oil or condensate tanks, and in certain types of service, such as for CBM production and dry shale gas, also have very low VOC content.

- <u>Sections 4.5.1.1-2 (Recommendations for Cover Design and for Closed Vent Systems)</u>:

The Alliance agrees with EPA's recommendations for cover design in general, but notes the ambiguity in this section and Section 4.5.1.2 regarding AVO inspections of storage vessel covers such as thief hatches. This section indicates that storage vessels should "be equipped with a cover . . . that routes emissions to the control device (or process) that meets the RACT level of control" and recommends AVO inspection monthly; however, the next section says the closed vent system should be "designed and operated with no detectable emissions (which can be monitored by [AVO] inspections." The ambiguity concerns whether any fugitive emissions detectable by any means are allowed by this recommended language. We supports a *de minimis* fugitive emission or leak rate below 500 ppm for cover seals and closed vent systems, such that leaks of this small magnitude are not generally detectable by AVO inspection and do not result in the cover, closed vent system, and emission control device together being less than 95 percent effective. The Alliance strongly opposes language that recommends or requires that all vapors be routed, or that allows zero emissions, even fugitive emissions below 500 ppm in magnitude, from covers and closed vent systems. Especially in the case of thief hatches and other covers designed to open and relieve pressure upon the storage vessel, any standard that requires or assumes no fugitive emissions whatsoever is impractical and unachievable.

- Section 4.5.1.4 (Recommendations for Control Device Operation and Monitoring):

This section requires control devices to operate "at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device." This language is problematic, as indicated above in comments on Sections 4.3.1.1 and 4.3.1.2, concerning the problem of VRU downtime and whether a combustor or redundant VRU is required, or even if shutting-in production is required in the absence of backup controls meeting RACT "at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device." This requirement is not consistent with EPA's VRU or combustor assumptions and cost analyses, and EPA has not even addressed the costs of shutting-in production every time a VRU or combustor may become inoperable or otherwise requires maintenance. In addition, the Alliance has made comments in the technical comments section of its OOOOa comment regarding the problematic, and inconsistent, use of the term "control device."

Also, with respect to enclosed combustion devices, EPA recommends that, in addition to being 95 percent destruction or control efficient, the device must be maintained in a leak-free condition; however, this latter requirement is ambiguous. Does this mean no leaks within the meaning of Subpart VVA, *i.e.*, at or above 500 ppm of VOCs? If so, this should be clarified, and would be consistent with WEA's concerns about sub-leak levels of fugitive emissions from covers and closed vent systems that do not result in less than 95 percent capture efficiency not constituting violations of EPA's recommended RACT level of control.

- Section 9.5 (Factors to Consider in Developing Fugitive Emissions RACT Procedures):

As currently proposed, the CTG fugitive emission control program does not allow for existing sources to maintain semiannual monitoring of components. Section 9.5 requires semiannual fugitive emission monitoring surveys at each applicable well site. The proposed rule goes on to recommend an increase to quarterly surveying in the event two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more of the components at a well site. If two consecutive semiannual monitoring surveys detect fugitive emissions at less than 1.0 percent, surveys may decrease to annual. *Id*. Based on EPA's recommendation, well site fugitive emission control requirements will either increase or decrease from the semiannual standard immediately. EPA's CTG recommendation is puzzling in light of the Agency's determination that quarterly monitoring is not cost effective.

Furthermore, later in Section 9.5 of the CTG, EPA provides that surveys may return to quarterly if a survey detects fugitive emissions at greater than 3 percent of the fugitive emission components at the well site. The Alliance questions whether EPA meant to subject well sites to quarterly surveys when two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more or whether they even have the legal authority to do so in light of the cost findings?"

The Alliance also requests that EPA recommend states allow for the gradual transition of existing sources into the fugitive emission control program under the CTG. As EPA can appreciate, the implementation of the fugitive emission control program under the CTG for existing sources must be different from the implementation of OOOOa for new and modified sources. Operators managing a significant number of existing sources—newly-subject to RACT—must be allotted a reasonable amount of time to implement the program field-wide. An initial, transitional phase for operators to bring their existing operations into any future RACT fugitive emission control program (e.g., rolling or multiple stage deadlines) is essential.

* * *

In conclusion, Western Energy Alliance appreciates the opportunity to provide detailed, substantive comments to OOOOa and CTGs. Please feel free to contact me regarding any questions with our comments.

Sincerely,

Kathleen M. Sgamma
Vice President of Government and Public Affairs