April 23, 2018

U.S. Department of the Interior
Bureau of Land Management
Mail Stop 2134 LM
1849 C St., NW
Washington, D.C. 20240
Attn: 1004–AE53

Re: Waste Prevention, Production Subject to Royalties, and Resource Conservation: Rescission or Revision of Certain Requirements, Docket ID No. BLM-2018-0001-0001, RIN 1004-AE53

To Whom it May Concern:

Western Energy Alliance (the Alliance) and the Independent Petroleum Association of America (IPAA) appreciate the opportunity to provide comments on the Bureau of Land Management's (BLM) proposed revisions of certain provisions of the Methane and Waste Prevention rule, or 2016 rule. The 2016 rule as promulgated exceeded BLM's authority under the Mineral Leasing Act (MLA), and that the decision to re-evaluate the rule is required. The proposed revision rule more accurately captures the scope of BLM's waste minimization authority, and will better ensure federal mineral interests are adequately protected without excessively burdening federal lands development with overreaching regulations.

IPAA represents thousands of independent oil and natural gas exploration and production companies, as well as the service and supply industries that support their efforts. Independent producers drill about 95% of American oil and natural gas wells, and produce about 54% of American oil and more than 85% of American natural gas.

The Alliance represents over 300 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 15 employees.

The 2016 Waste Prevention Rule Exceeds BLM's Statutory Authority

The 2016 rule exceeds BLM's statutory authority under the MLA and must be revised. The United States District Court for the District of Wyoming expressed significant concern with the rule. The court described BLM as having "hijacked the EPA's authority under the guise of waste management" and stated that "the BLM cannot use overlap to justify overreach."[1] Given such a strong warning of the legal

[1] Order on Mots. for Prelim. Inj., *State of Wyoming v. U.S. Dep't of the Interior*, No. 2:16-CV-0285-SWS (Jan. 16, 2017), attached as Appendix A.

vulnerability of the rule, it is logical and necessary that BLM move to substantively revise it to more accurately reflect the agency's statutory authority. Our comments on the 2016 rule, which are attached hereto as Appendix B and reincorporated in full by reference herein, provide an overview of our concerns with the technical and legal vulnerabilities of the 2016 rule.[2] Many of those concerns went unaddressed and are subject to the ongoing litigation referenced above. This letter raises further concerns with the 2016 rule.

The stated primary goal of the 2016 rule was to reduce methane emissions from oil and gas operations. During that rulemaking process, BLM repeatedly emphasized that the methane reductions achieved by the Proposed Rule justified its provisions. As the Wyoming court noted, however, BLM only has "authority to regulate the development of federal and Indian oil and gas resources *for the prevention of waste*." *Id*. at 15 (emphasis in original). Therefore, some emissions reductions may occur as a result of an otherwise lawful measure to prevent the "waste" of gas pursuant to BLM's authority under the MLA. But BLM's obligation to promulgate reasonable waste prevention measures does not confer any authority to regulate air quality. The Wyoming court also made clear that the "*protection of air quality* . . . is expressly within the 'substantive field' of EPA and states pursuant to the Clean Air Act." *Id*. (emphasis in original). Thus, in the context of the 2016 rule, BLM lacks authority to require the oil and gas industry to reduce methane (or other air) emissions.

Under the MLA, produced gas is "wasted" only if it could have been economically captured and marketed or put to beneficial use on the lease. Thus, to establish that a proposed waste prevention measure is a "reasonable precaution" against "waste" and authorized under the MLA, BLM must demonstrate that the gas can be economically captured by the operator or beneficially used on the lease. If a waste prevention measure renders gas capture or use uneconomic, then BLM has no authority to impose it.

Even BLM's original cost-benefit analysis reflects that the 2016 rule did not meet the standards required of BLM when adopting waste prevention measures.[3] For example, BLM estimated that its requirement to replace certain pneumatic pumps with zero-emission pumps would impose costs of $2.7 million per year, but would result in only $2.2 million in savings.[4] By its own estimate, BLM failed to demonstrate that the gas currently vented from the pumps subject to the 2016 rule can be economically captured by replacing the pumps with zero-emission pumps. Accordingly, the only way BLM could justify this particular measure on a cost-benefit basis was by adding in the $18 million in "monetized benefits" that it believed can be achieved in terms of climate change through the reduction in methane emissions that would occur if zero-emission pumps were used. This is just one example from the 2016 rule, but more broadly, the rule suffers from the same fundamental flaw—the only way BLM could justify the rule was to incorporate global climate change benefits. As the Wyoming court put it, "the Rule only results in a 'net benefit' if the 'social cost of methane' is allowed to be factored into the analysis . . . [and] [t]he Court questions whether the 'social cost of methane' is an appropriate factor for BLM to consider in

[2] *Comments on Waste Prevention Rule*. Western Energy Alliance, IPAA, American Exploration & Production Council, and U.S. Oil & Gas Association. April 22, 2016.

[3] As detailed in the Alliance and IPAA's April 22, 2016 comments, the Alliance and IPAA disagree with BLM's original cost-benefit analysis.

[4] BLM, *Regulatory Impact Analysis for: Revisions to 43 CFR 3100 (Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and Gas Operations) Additions of 43 CFR 3178 (Royalty-Free Use of Lease Production) and 43 CFR 3179 (Waste Prevention and Resource Conservation)* 62 (2016) ("2016 RIA").

promulgating a resource conservation rule pursuant to its MLA authority."[5] *Id*. at 21 (citing the RIA at 5-6).

BLM lacks authority under the MLA, or any of the other statutes that BLM cites in the 2016 rule's preamble, to regulate the air quality at oil and natural operations on federal and Indian leases for the purpose of controlling climate change. That authority, to the extent it exists, has been given by Congress exclusively to EPA and the states under the Clean Air Act. By relying on the benefits of methane reductions to justify its waste prevention measures, BLM relied on factors which Congress did not intend it to consider when developing "waste prevention" measures under the MLA (or any of its other authorizing statutes).

As noted above, to demonstrate that a particular measure is a reasonable precaution against waste, BLM must demonstrate that the gas subject to the measure can be economically captured by the operator. Potential global societal benefits resulting from methane reductions have no place in BLM's determination of what may be a reasonable waste precaution. Because those benefits do not flow to the operator in any discernable fashion, they are not revenue that can be spent to make capture of the gas economical. Similarly, such benefits do not flow to the American public in the form of increased royalties; and it is royalty benefits, not global climate change benefits, that BLM is statutorily authorized to ensure. *See* the Federal Oil and Gas Royalty Management Act, 30 U.S.C. §§ 1701-1758. Thus, while an otherwise "reasonable" measure to prevent the "waste" of gas may have the incidental effect of reducing the amount of methane that is emitted from oil and gas operations, such a measure may not be made "reasonable" solely by virtue of that incidental effect. Yet, that is precisely how the 2016 rule was structured and why it was unlawful.

Federal oil and gas lessees have a right to develop the oil and natural gas resources on their leases, subject to the requirement that they take "reasonable precautions" to prevent the "waste" of those resources, and that they comply with other applicable federal laws and regulations, like the ones adopted by EPA to regulate air emissions. If they are not "wasting" those resources—i.e., if those resources cannot be economically captured—BLM may not impose so-called waste prevention measures under its MLA authority. The issuance of an executive branch edict (i.e., the Obama Climate Action Plan and Methane Strategy) to selectively impose emission controls on certain industry sectors does not somehow transform BLM's MLA authority over waste to authorize air quality regulation. Only Congress can delegate such authority and it has not done so. Thus, the 2016 rule exceeded BLM's Congressional delegation of its waste authority. Moreover, the oil and natural gas industry has and will continue to work voluntarily to economically reduce methane emissions, but federal oil and gas lessees may not be made to bear the costs of reducing those emissions under the guise of BLM's authority to impose "reasonable precautions" to prevent the "waste" of gas.

The Revised Rule Aligns With the Agency's Statutory Authority

Given the clear overreach by BLM in the 2016 rule, we support the changes being proposed by BLM to bring the Waste Prevention rule back in alignment with Congressional intent and statutory authority. What BLM should have done in its original rulemaking, and is poised to do in this Proposed Rule, is focus on a tailored update to Notice to Lessees 4-A (NTL-4A).

[5] The social cost of methane was formally withdrawn by Executive Order No. 13783, *Promoting Energy Independence and Economic Growth*, meaning it is no longer a suitable metric for rulemaking.

We support BLM's decision to remove "air quality" provisions including requirements for well drilling, well completions, fugitive emissions monitoring, pneumatic controllers, pneumatic pumps, and storage vessels. BLM's proposal correctly recognizes that the agency retains authority under 43 C.F.R. § 3179.4 to determine whether any natural gas is "avoidably" lost (and therefore royalty-bearing) through operator negligence, failure to take reasonable measures to prevent or control the loss, or failure to comply with applicable laws and regulations. Thus, the Proposed Rule will still provide emissions co-benefits through § 3179.4 (among other provisions), but consistent with BLM's statutory authority. BLM's decision to defer to EPA and states to develop and promulgate air quality regulations is entirely appropriate, consistent with existing statute and historical agency practice, and corrects a significant legal flaw in the 2016 rule.

Even if BLM had the statutory authority to regulate air quality, which it does not, the 2016 rule does not provide a clear and compelling case in favor of its air quality benefits. BLM stated (without explanation) during the 2016 rulemaking that its obligation under the Federal Land Policy and Management Act (FLPMA) to manage public lands under the principle of multiple use, which is defined as "management in a 'harmonious and coordinated' manner 'without permanent impairment to the quality of the environment,'" may provide it with the authority to regulate air quality and methane emissions. But that general reference to the "permanent impairment of the environment," which is found only in the definition section of FLPMA, cannot be read as an express or implied grant of authority to BLM to set its own methane emission standards, or to limit methane emissions out of a concern for the effect they may have on climate change. There is nothing in the substantive provisions of FLPMA that would support such a reading or that would give BLM any guidance to observe in exercising such an authority. Indeed, the United States District Court for the District of Wyoming expressly disagreed "with BLM's suggestion that FLPMA grants it broad authority to promulgate its own regulations directed at air quality control," and instead recognized that "[a]t its core, FLPMA is a land use planning statute."[6] Especially in light of the detailed and complex provisions that Congress has established for the regulation of air quality in the Clean Air Act, it is unreasonable to suppose that Congress would give BLM the authority to regulate air quality completely untethered to any substantive guidance from it as to how to exercise that authority. *See Whitman v. Am. Trucking Ass'n*, 531 U.S. 457, 468 (2001) ("Congress . . . does not alter the fundamental details of a regulatory scheme in vague or ancillary provisions—it does not, as one might say, hide elephants in mouseholes.") At most, the provision in FLPMA can be read as requiring BLM to ensure that activities conducted on federal lands comply with all applicable environmental standards as established by the agencies with express and substantive authority from Congress to do so.

If BLM somehow had authority to require federal oil and gas lessees to reduce methane emissions out of a concern for the effect they might have on climate change, BLM would still have to provide a reasonable justification for doing so, which it has not. The significant cost of the 2016 rule vastly outweighs the marginal reductions in global greenhouse gas (GHG) emissions. Specifically, global methane emissions are estimated at 6,875 million metric tons CO_2-eq per year, whereas U.S. methane emissions are about 708 million metric tons CO_2-eq per year, or about 10.2% of global emissions. BLM estimated that the 2016 rule will reduce between 4.1 and 4.2 million metric tons of CO_2-eq per year.[7] Taking BLM's 4.2 MMT CO_2-eq per year, the Proposed Rule provides a reduction of 0.061% of global methane emissions. More importantly, methane emissions make up only a small portion of total global GHG emissions. EPA estimates put annual global greenhouse gas emissions at approximately 45,863

[6] Order on Mots. for Prelim. Inj., *State of Wyoming v. U.S. Dep't of the Interior*, No. 2:16-CV-0285-SWS at 15 n.7 (Jan. 16, 2017).
[7] *Fact Sheet on Methane and Waste Reduction Rule*. Bureau of Land Management. January 2016.

million metric tons of CO_2-equivalent (CO_2-eq) in 2010.[8] By BLM's most ambitious estimates, which are likely overstated, its Proposed Rule will reduce greenhouse gas emissions by 4.2 million metric tons of CO_2-eq. That's approximately 0.0092% of global greenhouse gas emissions. Given that climate change is a global phenomenon where emissions are measured on a country-by-country basis, it simply is not credible to assert that a 0.0092% reduction in GHGs is "significant" or somehow justifies the 2016 rule.

In contrast, the domestic economic consequences of the 2016 rule for oil and natural gas operations on federal and Indian leases were significant, immediate, and concrete. Not only did the rule impose initial capital costs to retrofit equipment at existing facilities, but several provisions including the LDAR and the gas capture programs imposed re-occurring annual costs. As noted above, once the social cost of methane was adjusted to properly apply the methodology, the 2016 rule resulted in a "net cost" of between $581 and $945 million over a 10-year period (depending on the discount rate used). By failing to reconcile the significant and recurring domestic costs of the 2016 rule with the limited impact on global GHG emissions, the 2016 rule was arbitrary and capricious.

The 2016 Rule Relied on Flawed Assumptions

Not only does the 2016 rule exceed BLM's statutory authority, the 2016 rule was premised on several flawed assumptions, including several that led to substantially overstated projected emissions reductions. BLM has correctly identified some of those flaws and taken steps to address them in the Proposed Rule.

For example, we support the removal of waste-minimization plans from the rule. We agree with BLM that the plans were an unnecessary administrative burden that served no practical purpose in reducing waste. Requiring waste minimization plans is not necessary to achieve BLM's stated goal, and is therefore not a "reasonable precaution" against "waste" of gas under the MLA. In creating waste minimization plan requirements, BLM erroneously assumed that unless operators are required to gather certain information that they will need to comply with the venting and flaring limits, they will not do so. This is an incorrect assumption.

Operators routinely conduct extensive planning about the current and future availability of infrastructure in their development plans for the express reason of minimizing waste and maximizing the capture and sale of valuable product. Moreover, the royalty regulations themselves require operators to pay royalties on wasted gas if they do not plan appropriately. Thus, having to generate and collect the information required by the 2016 rule and then submit it in a prescribed format to BLM for review would serve no useful purpose. Preparing the plan for BLM wastes the time and resources of operators in preparing the plan, as well as the time and resources of BLM in reviewing the plans to determine if they are "adequate and complete." Review of waste minimization plans also creates a drain on agency resources, which would likely lead to increased APD processing times and does nothing to solve the backlog in Right of Way (ROW) approvals, an issue we have repeatedly raised. Removal of the waste minimization plan requirement also adheres to the principles of Executive Order No. 13777, *Reducing the Regulatory Burden*, because it is an ineffective measure for actually minimizing waste for the reasons explained above.

In addition, BLM also now correctly asserts in the revised Regulatory Impact Analysis (RIA) that previous agency assumptions about venting and flared gas rates are overstated compared with actual data. *See*

[8] U.S. EPA, Climate Change Indicators in the United States, https://www3.epa.gov/climatechange/science/indicators/ghg/global-ghg-emissions.html

Proposed Rule RIA at 19-21 (describing BLM's updated estimates as "differ[ing] markedly from the GAO's estimates for 2008"). The revised data and assumptions regarding rates of venting and flaring correct a major deficiency in the 2016 rule RIA. This correction leads to a more accurate assessment of both the problem the agency is trying to address as well as the benefits the new rule will yield for the costs it will impose. Although we appreciate that BLM has updated its assumptions regarding the volume of gas venting and flared on federal and Indian leases, there are still deficiencies in the methodology that likely overstate the problem.

The reality is that without duplicative and burdensome federal rules, industry has made tremendous progress in addressing issues associated with venting, flaring, and methane emissions. According to EPA's most recent greenhouse gas inventory,[9] between 1990 and 2016, methane emissions from petroleum and natural gas systems declined 14% while natural gas production increased 50%. In the 2016 inventory (published in 2018), petroleum system methane emissions declined 3% since 1990, and methane from natural gas systems declined 16% since 1990. These decreases come despite a 71% and 48% increase in production, respectively, since 2005.

Most important, the most recent EPA data, which applies more accurate calculation methodologies, show that emissions from associated gas venting and flaring decreased 36% from 2015-2016. *See* 2018 GHG Inventory Report at 3-64. In fact, EPA revised petroleum system methane emission estimates going back to 1990, resulting in an average decrease of 28% for a given year relative to previous estimates due to the "recalculation of associated gas venting and flaring emissions using a basin-level approach." *Id*. at ES-6 (the same recalculation results in increased CO_2, however). EPA's new data reveals that the 2016 rule was premised on inaccurate information regarding the volume of methane emissions attributable to venting and flaring, and is therefore, an arbitrary and capricious agency action that was premised on faulty logic and without adequate support on the record. EPA's new and updated data further supports the agency's rationale for the Proposed Rule.

Instead, BLM relied on an outdated 2008 Government Accountability Office report that concluded significant volumes of gas were being lost through venting or flaring that could be economically recovered. This 10-year-old report is out of date, and it would be improper to rely on it for any further rulemaking. BLM now correctly incorporates the most recent data in the RIA supporting the Proposed Rule. For example, the Proposed Rule factors in new state-level rules and flaring programs that came about or were changed significantly after the 2016 rule was finalized, like those in Colorado, California and North Dakota. BLM also notes that emission factors for liquids unloading and well completions in its greenhouse gas inventory have been updated, which further underscores how the GAO report does not reflect the current state of industry data or the best available data.

The 2016 rule also included gas capture targets that effectively imposed a double penalty on operators for lost gas. Operators have an incentive to capture and sell all gas that can be economically captured. If an operator flares or vents gas that can be economically captured, such gas is "avoidably lost" and thus royalty-bearing. Therefore, even without the gas capture limits, the government already receives the royalties it is due, regardless of whether gas is actually captured. The stringent and arbitrary gas capture targets in the 2016 rule, however, required operators to capture gas even when uneconomic to do so (i.e., when capture is more expensive than the revenue generated from the sale). Therefore, the

[9] *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2015*, EPA, April 12, 2018 (available at https://www.epa.gov/sites/production/files/2018-01/documents/2018_complete_report.pdf).

gas capture requirements exceeded BLM's authority by imposing royalty on gas that was "unavoidably" lost. For these reasons, BLM appropriately removed this provision from the Proposed Rule.

The 2016 rule also relied on flawed assumptions about the benefits of many provisions within the rule itself. Most notably, BLM significantly overstated the benefits of its leak detection and repair (LDAR) program by, among other things, overestimating the frequency and rates of leaks that would be found and fixed. The most recent data collected in Colorado to evaluate the effectiveness of its Regulation 7 LDAR program, upon which the 2016 BLM LDAR program was based, show a rapidly diminishing rate of leak detection following an initial inspection. As discussed below, Colorado's experience with "diminishing returns" is consistent with the observed results of other regulatory LDAR programs and studies in the upstream oil and natural gas industry. BLM failed to take this into account when developing the 2016 rule. In fact, BLM relied on the State of Colorado's outdated initial 2014 economic impact analysis, which estimated that annual inspections will produce a 40% emissions reduction, semi-annual inspections will result in a 50% emissions reduction, and quarterly inspections will result in a 60% emissions reduction. This 40/50/60 "estimate" has since been proven incorrect.

Following promulgation of Colorado's LDAR program in 2014, approximately 42% of facilities surveyed were found to have a leak on the initial inspection. Critically, this rate dropped to 9% by the second quarter of 2015. The first LDAR annual report summary for 2014 indicated a similar trend, with an initial leak detection rate of 35% per inspection, dropping to just over 7% per inspection in the 2015 report. The 2016 Colorado data continue to demonstrate this trend, as the leak detection rate per inspection fell again to approximately 4.8% in 2016. These data indicate that after just a few years of the 2014 Regulation No. 7 rule implementation, leak rates have declined and continue to decline significantly with a precipitous drop-off in leak rate following the initial inspection. This Colorado-specific data and experience demonstrates that additional inspections in the subsequent years of an LDAR program result in diminishing returns expressed as a lower volume of leaks found and emissions reductions realized. Accordingly, based on leak detection rate data alone, it is apparent that in the subsequent years of Colorado's LDAR program, the costs of additional inspections relative to emissions reductions is increasing and will likely increase over time.[10] It is important to note that each facility inspection covers hundreds or thousands of individual components, so the leak rate by component (*see* API study below) is significantly lower than the percentage of facilities where a leak was found.

A 2017 Stanford University computational analysis of facility and mitigation uncertainties on the effectiveness of the EPA-based LDAR requirements also raises questions about BLM's reliance on OOOOa-style LDAR to determine benefits.[11] Researchers used a model-based approach to evaluate the effectiveness of LDAR programs. The study found that a skewed leak size distribution, or small number of leaks responsible for a large fraction of emissions, strongly influences mitigation potential. It also found that emission reductions from optical gas imaging (OGI)-based approaches can range from 15-70%, while EPA assumes 60% for semi-annual surveys and 80% for quarterly surveys. OGI offers diminishing returns with increased number of LDAR surveys over the year, with highly variable benefits, which echoes industry's experience with Colorado's LDAR program. The study concludes that over 50% of mitigation can be achieved by an annual LDAR schedule at any survey distance, and recommends performance-oriented targets and flexible policy mechanisms for industry to improve overall program

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[10] BLM's 2016 economic analysis confirms that the program costs would continually increase relative to benefits, noting that the cost of LDAR surveys would remain constant throughout the life of the 2016 waste prevention rule, regardless of the decreasing benefits of such surveys. *See* 2016 RIA at 106.

[11] *Designing Better Methane Mitigation Policies: the Challenge of Distributed Small Sources in the Natural Gas Sector*. Ravikumar and Brandt, attached as Appendix C.

effectiveness. In contrast, the LDAR program under the 2016 rule was a one-size-fits-all, prescriptive requirements with no consideration of program performance, particularly over the life of the program.

Meanwhile, a 2018 API analysis of component leak monitoring data yielded similar results. API evaluated EPA's OOOOa LDAR assumptions and found that EPA overestimated the cost of control ($/ton) of LDAR for both methane and VOCs at well sites and compressor stations as documented in EPA's Technical Support Document (TSD) that accompanied the final Subpart OOOOa rule. This is particularly problematic in the context of the 2016 rule given that BLM did no independent data gathering or analysis, opting instead to rely solely on EPA's data and analysis covering new and modified facilities. API completed a blinded survey of operating companies that resulted in the collection of data from LDAR surveys completed using optical gas imaging (OGI) from six (6) member companies, covering a wide range of operators and facility types at new and modified sites located in more than 14 states. In total, API's study covered the following:

- Six companies providing LDAR survey results at new and modified well site locations
- 4,117 well sites
    - 1,841 Oil well sites
        - 1,164 single well sites
        - 677 multi well sites
    - 2,276 Gas well sites
        - 1,521 single well sites
        - 755 multi well sites
- 1,958,033 components surveyed
    - 7,837 components were determined to be leaking using OGI

The data demonstrated an average initial leak incident rate of 0.4% of components surveyed. This leak rate is for sites just beginning an LDAR program (i.e., no organized LDAR efforts had yet been made). These findings strongly contradict the 1.18% leak rate assumed by EPA in developing OOOOa, which BLM in turn relied on in the development of the 2016 rule. Importantly, the significantly lower component leak rate in the API study includes data for existing but modified sites. Accordingly, it is reasonable to conclude that for the older, existing sites subject to the 2016 rule, leak rates were vastly overestimated, meaning the forecast emissions reductions and estimated benefits were overstated and incorrect. The full API analysis is appended to this comment letter for the record as Appendix D. Taken together, the fact the 2016 rule does not factor in the diminishing effectiveness of LDAR programs in the upstream oil and natural gas sector, combined with a significantly overestimated component leak rate, means the 2016 rule vastly overestimated the benefits from the LDAR program. This is a critical flaw in the rule because, setting the flaring limits aside, the 2016 LDAR program was responsible for the vast majority of the estimated annual emissions benefits of the rule. *See* 2016 RIA at Table 1-3(d).

Finally, in contrast to the claims of several states and environmental groups during the litigation, the 2016 rule does not provide any meaningful evidence or analysis of ozone (or other public health) benefits, nor does it provide any indication that the VOC reductions estimated by the rule will actually result in such benefits. The 2016 RIA specifically stated that "the analysis does not monetize the benefits to public health and the environment of reducing VOC emissions." 2016 RIA at 6. In other words, the estimated VOC reductions in the 2016 rule were ancillary "co-benefits" of the estimated methane reductions. Notably, methane is not a significant ground-level ozone precursor, yet it was the target, the only monetized pollutant, and overwhelming "benefit" driver of the 2016 rule. Another way to put this is that the 2016 rule was a methane rule and not an ozone rule. Further evidence of this is the fact that BLM did not conduct or provide any photochemical modeling or other analysis specific to VOC reductions that would inform whether and where the 2016 rule's estimated reductions in VOCs would result in a corresponding reduction (or even increase) in ozone levels. Any statement regarding such benefits, therefore, is unsupported on the record and nothing more than unfounded speculation.

The lack of record evidence on ozone benefits in the 2016 rule is likely due to the photochemical complexity and high regional variability of ozone formation. Perhaps more importantly, this issue further highlights why BLM is not and should not be in the business of air quality regulation. Although VOCs, along with Nitrogen Oxides (NOx), are an ozone precursor, VOC reductions do not necessarily yield corresponding reductions in ozone levels for several reasons. To begin, the creation of ozone is an incredibly complex photochemistry and meteorological phenomenon that is still not fully understood. Whether and when ozone levels may be impacted by precursor emissions depends on the given day, time of year, location and topography, and meteorological and atmospheric conditions among many other factors. Any regulation promising "ozone" benefits must account for the complexity and geographic specificity of ozone creation. The 2016 rule lacks any such consideration or evidence.

Second, areas that attain National Ambient Air Quality Standards (NAAQS) for ozone are, by definition, areas in which ozone levels have been determined to be within acceptable levels with an adequate margin of safety. For example, North Dakota and New Mexico's oil-producing regions meet federal ozone standards. Even if there were modeling or other analysis on the 2016 record to inform the ozone issue in these areas, it would not be correct to assume the same level of ozone health benefits from reduced VOC emissions in "attainment" areas. Even in ozone nonattainment areas, the calculus is extremely complex. For example, some nonattainment areas, such as the San Joaquin Valley, are NOx-limited, meaning no matter how much VOC emissions are reduced, ozone levels will not be impacted because NOx emissions are the primary driver of ozone creation. For example, in many nonattainment areas, EPA modeling has demonstrated 70 ppb ozone compliance can be achieved without any VOC reductions. Thus, depending on the area, a regulatory program that reduces VOCs but increases NOx, or *vice versa*, can actually make the ozone problem worse. Accordingly, without a specific, modeled nonattainment area by nonattainment area analysis, it is not possible to draw any conclusions about the specific "ozone" benefits of reducing VOCs (or NOx). In fact, in the absence of such modeling, regulatory programs that focus on one precursor (VOCs) over another (NOx) may actually exacerbate ozone levels in certain areas.

In sum, in the context of these comments and the BLMs 2018 Proposed Rule, because such ozone analysis is entirely missing from the 2016 record, BLM is not required to provide justification or record evidence now for removing provisions of the 2016 rule that would have resulted in VOC reductions. There simply is no evidence on this record that would allow any reviewer to conclude that the 2016 rule provided any "ozone" benefits, or that the 2018 Proposed Rule would reverse those benefits.

The Revised Rule Must Consider Per Well Impacts to Marginal Wells

Based on BLM's updated economic analysis, the net cost of the 2016 rule is now estimated to be between $581 and $945 million over a 10-year period (depending on the discount rate used) which is close to the net cost of between $876 million and $1,170 million estimated by economics firm John Dunham & Associates (JDA) in its 2016 review of the rule.[12] This differs substantially from BLM's

[12] *See* Memorandum to Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance, from Mike Stojsavljevich, John Dunham & Associates, regarding *Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR 3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43*

estimated net benefits of between $119 million and $245 million estimated at the time of the original rulemaking.[13] This reversal is driven largely by the removal of the global "social cost of methane" from the benefits calculation. This, alone, warrants BLM's administrative reconsideration of the 2016 rule and provides support for the much scaled back 2018 Proposed Rule, which for the first time and without incorporating global methane reductions, results in a net benefit. *See* 83 Fed. Reg. at 7,939 (estimating a total net benefit of $578-942 million depending on the discount rate).

Although we appreciate that BLM has revised its net costs and benefits projections, we urge BLM to further refine its RIA to better account for the true cost of both the 2016 rule and the Proposed Rule, particularly as it relates to small operators and marginal wells. As it did in the 2016 rule, BLM continues to improperly assess impacts on a per-company profit margin basis. *Compare* 2016 Rule, 81 Fed. Reg. at 83,013-14 (estimating the rule would result in an average reduction in profit margin of 0.15%), *with*, 2018 Proposed Rule, 83 Fed. Reg. at 7,940 (estimating a per-entity reduction in compliance costs resulting in an average increase in profit margin of 0.19%). A "per-company profit margin" is a meaningless way of assessing the impacts of either rule.

A per-company profit margin fails to account for the number of wells an operator has in its portfolio and the individual attributes of each well. For example, a per-company profit margin fails to account for key factors such as where an operator's wells are in their life cycle, an operator's agreements to transport and process produced oil and gas, the geologic formation being targeted, the costs to drill and complete a given well, debt loads, and myriad other considerations. Simply put, an operator with 1,500 oil or gas wells operating early in the wells' life cycle will have an entirely different economic and business calculation than an operator with 15 marginal wells nearing the end of their life.[14] Furthermore, an increase or decrease in company profit margin will not necessarily drive an operator's determination of whether to keep individual wells in production. Instead, an operator must consider whether the costs of production exceeds the revenue generated for a given well, in addition to other factors such as keeping a lease from expiring.[15] In short, BLM's per-company profit margin does not provide an accurate or helpful means of assessing how these rules will actually impact operations and production on federal and Indian leases.

As reflected in the attached report from John Dunham & Associates (JDA), attached hereto as Appendix E, a far more accurate way to assess the rules' impact is on a per-well basis, with a particular emphasis on how the per-well cost of the rule affects marginal or low-production wells. *See* 2018 JDA Report at 8

CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179), attached as "Appendix A" to the Joint Trades comments provided here at Appendix B.

[13] U.S. Bureau of Land Management, *Regulatory Impact Analysis for: Revisions to 43 CFR 3100(Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and gas Operations)*, at: www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.11216.File.dat/VF%20Regulatory%20Impact%20Analysis.pdf

[14] The scenario that different operators have portfolios consisting of wells at different stages of their lives is commonplace. An operator does not necessarily have a diverse portfolio of wells ranging from those that are recently drilled to those that are marginal. Rather, operators that focus on exploration often hold wells in the early stages of their lives. By contrast, some operators focus on acquiring wells that are marginal or nearing the end of their productive lives, relying on relatively low operating expenses to generate an aggregate profit. Those operators that hold a proportionately large number of marginal wells will be most impacted by the 2016 Rule.

[15] These same considerations drive decisions for well operators, regardless of size or expertise. *See* Jon Murray, "Nearly a Third of Denver Airport's Oil and Gas Wells Are Losing Money, an Audit Says. Should They be Plugged?" *Denver Post* (Mar. 15, 2018), available at https://www.denverpost.com/2018/03/15/dia-oil-and-gas-wells-losing-money/.

("[P]er-well cost is the only appropriate metric for determining the Rule's impacts."). To this end, there are two critical points to consider from the JDA report: (1) marginal wells are particularly susceptible to increases in operating costs or swings in commodity prices; and (2) because each well is unique, operators make decisions regarding whether to keep a marginal well operating based on the economics of any given well (i.e., on a "per well" basis).

With respect to price sensitivity, the economic impacts to a marginal well are different from new or more prolific wells. The economic life cycle of an oil or natural gas well is complex. Some wells are drilled but never meet expectations, while some wells are drilled and exceed expectations. What is true for any well, however, is that it will experience a decline in production over time. As a well nears the end of its life, it becomes less and less profitable. Wells at this end of the life cycle are known as "marginal" or "low production" wells.[16] As the JDA report explains, marginal wells are particularly susceptible to commodity price fluctuations. Thus, "marginal wells become unprofitable to produce whenever oil and/or gas prices drop below a fluctuating crucial point, or when costs are increased either through regulation or operational dynamics." Among other things, this price sensitivity means that marginal wells are especially at risk of being prematurely abandoned, leaving large quantities of oil and gas in the ground (i.e., exacerbating "waste" and reducing royalties). *See e.g.*, IOGCC 2016 Report at 1 (explaining that "in many cases marginal wells may be accessing a reservoir that holds two-thirds of its potential value.").

With respect to marginal well economics, like any business, absent other circumstances, an oil or natural gas operator will not continue to operate an unprofitable well. Importantly, the decision about whether to continue to operate any given well is made based on the economics and circumstances of that well, not necessarily on a per-company profit basis. As the JDA report indicates, a well can be "marginal" for a variety of reasons, including because it is at the end of its life cycle or because it is located in a remote area making its operation unusually expensive. Regardless of why a well is marginal, the per-company profit margin does not account for the varying dynamics that control marginal well economics or influence an operator's decision to continue producing or abandon the well.

To meaningfully assess these rules' economic impacts, then, it is necessary to analyze how the rules' per-well costs affect marginal wells. This method of determining impacts is particularly important here, as the vast majority of affected wells are "lower production" or "marginal wells." *See e.g.*, 81 Fed. Reg. at 83,029 ("[W]e note that roughly 85 percent of wells on Federal and Indian leases are classified as low production wells (*i.e.*, produce 15 barrels of oil equivalent per day or less)."). Importantly, simply because these wells are low-producing does not mean they are not a valuable economic piece of the industry. For example, the IOGCC estimates that in 2016 all marginal wells in the United States produced oil and natural gas valued at $15.8 billion. *See* IOGCC Report at 31. The value of such wells affected by BLM's rule is obviously less, but nonetheless, important.

When both the impacts to marginal wells of the 2016 rule and the Proposed Rule are considered on a per-well basis, the results are illuminating. The following table is taken from the Dunham report, attached to these comments. It demonstrates that if the 2016 rule were to remain in effect, the rule would result in a per well cost of $7,466.[17] Factoring in an updated pricing structure, this would result in the removal of 12,646 marginal wells from production on federal and Indian leases. This is compared to

[16] For a more detailed discussion of marginal wells, see "*Marginal Wells, Fuel for Economic Growth*, 2016 Report," provided by the Interstate Oil and Gas Compact Commission (IOGCC), available for purchase at https://iogcc.myshopify.com/products/marginal-well-report-2017.

[17] As noted in the 2018 JDA report, this figure is only for oil wells with associated natural gas.

the Proposed Rule's estimated impacts of $82 per well, which would result in the removal of 678 marginal wells from production.

Table 1
Marginal Well Impact by State on BLM Leases
(2016 BLM Rule vs. Proposed 2018 Rule)

			2016 Enacted Rule			2018 Proposed Rule		
State	BLM Active Wells	BLM Oil Wells	Estimated Cost	Cost Per Well	Est. Marginal Well Reduction	Estimated Cost	Cost Per Well	Est. Marginal Well Reduction
AZ	1	0	$1,420	$7,466	0	$16	$82	0
CO	6,752	3,296	$24,609,136	$7,466	-1,121	$271,654	$82	-225
ID	-	-	$0	$0	0	$0	$0	0
MT	2,742	1,650	$12,317,670	$7,466	-424	$135,971	$82	-11
ND	2,255	2,211	$16,508,474	$7,466	-12	$182,233	$82	0
NE	31	28	$211,286	$7,466	-8	$2,332	$82	-2
NM	30,563	15,092	$112,680,976	$7,466	-5,323	$1,243,854	$82	-104
NV	97	95	$710,562	$7,466	-42	$7,844	$82	-2
OR	-	-	$0	$0	0	$0	$0	0
SD	84	62	$466,601	$7,466	0	$5,151	$82	-15
UT	8,879	4,885	$36,470,000	$7,466	-932	$402,582	$82	-60
WA	-	-	$0	$0	0	$0	$0	0
WY	32,294	10,681	$79,744,572	$7,466	-4,782	$880,278	$82	-259
Total	83,698	38,000	$283,720,696	$7,466	-12,646	$3,131,915	$82	-678

These numbers speak for themselves. Although there are still important impacts to marginal wells associated with the Proposed Rule, they are substantially less. From this perspective, the Proposed Rule is significantly improved and represents a reasonable restraint on waste prevention and a reasoned agency decision on the record. Most importantly, the Proposed Rule largely avoids the disastrous impacts, both in economic and waste terms, for marginal wells promised by the 2016 rule.

Although the Proposed Rule does not contain a per-well economic impact analysis, the BLM recognizes that the 2016 rule would have had disproportionately severe economic burdens for marginal and low-producing wells. *See e.g.*, 83 Fed. Reg. at 7,940 ("[M]ost of the emissions-based requirements in the 2016 final rule (including LDAR, pneumatic controllers, pneumatic pumps, and liquids unloading requirements) would impose a particular burden on marginal or low-producing wells. There is concern that those wells would not be able to be operated profitably with the additional compliance costs imposed by the 2016 final rule."). this is confirmed by the 2018 JDA report discussed above and was also reflected in JDA's conclusions about the 2016 rule, which have been updated and still show that the 2016 rule would leave 8.5 million barrels of developable oil in the ground. Thus, although the 2016 rule may reduce some above-ground waste, it would have led to underground waste through premature abandonment of wells, largely through impacts to marginal wells. Subsurface waste occurs when an oil and gas reservoir is developed in a manner that causes "reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations." *See* 43 C.F.R. § 3160.0-5. Subsurface waste can occur when a well is prematurely abandoned because, once abandoned, a well may not return to its former production, leaving the unproduced hydrocarbons beneath the surface.[18] The 2016 rule almost entirely ignored this critical waste component, and in this respect was arbitrary and capricious. Furthermore, not only does the 2016 rule lead to underground waste, the 8.5 million barrels that would have been left in the ground equated to a loss of about $528 million in direct economic activity at the time.

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[18] *See* J. Howard Marshall & Norman L. Meyers, *Legal Planning of Petroleum Production*, 41 Yale L. J. 33, 66 n.124 (1931); *accord* Thomas P. Battle, *Lease Maintenance in the Face of Curtailed/Depressed Markets*, 32 Rocky Mtn. Min. L. Inst. § 14.05[4] (1986) (noting that premature abandonment of wells leads to waste).

The Revised Rule More Accurately Considers Costs and Benefits Than the 2016 Rule But Still Imposes Administrative Costs

BLM's review of the 2016 RIA also recognized other flaws in that analysis, many of which were identified in our earlier report. [19] JDA also made these conclusions in a declaration presented in the United States District Court for the District of Wyoming.[20] The calculation of benefits to operators from recovered natural gas used in the 2016 RIA was one such flaw as it was based on estimated natural gas prices that were significantly higher than those in effect when the Rule was drafted. The 2016 RIA based its recoverable gas prices on a figure of between $3.69 and $5.67 per thousand cubic feet, with a 2017 estimated price of $3.80. The current spot price is well under $3.00 per Mcf.[21] The 2016 RIA also miscalculated costs. By focusing solely on the engineering costs of the rule, it failed to account for the cost to society of reduced petroleum production that would result from the 2016 rule. OMB Circular A-4 clearly states *with regard to measuring costs, you should be sure to include all the relevant costs to society whether public or private.*

BLM's RIA for the Proposed Rule still suffers from some of these flaws, but overall represents a more thorough and objective analysis that adheres more closely to OMB guidance. The 2016 rule RIA met only six of the 16 requirements laid out by OMB, whereas the new RIA meets most of the 16 steps. *See* 2018 JDA report.

Importantly, JDA found the 2018 RIA still overestimates benefits by not accurately accounting for significant administrative costs on operators. Although BLM recognizes that there will still be administrative costs to industry under the Proposed Rule, it estimates these to be minor ($261,973 annually in the 13 states affected by the Proposed Rule) based on an assumption that 4,010 hours of work would be required. This is likely underestimated for two reasons.

First, the BLM significantly underestimates the number of wells that would be subject to requests for approval for royalty-free testing and use. The agency suggested that there were 1,111 well sites subject to flaring restrictions in the 2016 RIA. It is expected that operators of these wells would at least apply for royalty-free approval for on-lease operations or during some period of well testing. This means that at least 1,111 administrative filings would be conducted at some point in time. Rather than 1,500 hours being spent on these requests, JDA estimates 2,200 hours would be spent.

Second, under the provisions outlined in 43 C.F.R. § 3179, in the absence of State regulations for federal lands and tribal regulations for tribal lands regarding the venting or flaring of oil-well gas, there would be a requirement for an evaluation on case-by-case basis. The RIA suggests that this could take 80 hours of administrative time, but only speculates that 20 of these would be performed per year. Since much of the growth in the industry is occurring in new development areas, it is likely that this would be much more significant. In the 2016 RIA, flare metering rules were expected to impact 635 sites. This is more likely to be the number impacted by this rule, meaning that the number of hours required for compliance would grow from 1,600 to 50,800. Taking these two changes into account, the Proposed Rule would still impose about $3.521 million in administrative costs on the industry.

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[19] US Bureau of Land Management. *Regulatory Impact Analysis for the Proposed Rule to Rescind or Revise Certain Requirements of the 2016 Waste Prevention Rule*, February 5, 2018

[20] *Declaration of John Dunham* (Dec. 23, 2016) Wyoming v. U.S. Dep't of the Interior, Nos. 2:16-cv-00285-SWS, 2:16-cv-00280-SWS , attached hereto as Appendix F.

[21] Currently the price is about $2.81 per Mcf based on the Henry Hub price as of April 6, 2018, U.S. Dep't of Energy, Energy Information Administration, *Natural Gas Weekly Update for week ending March 28, 2018*, March 29, 2018, at: www.eia.gov/naturalgas/weekly/#tabs-prices-2

Overall, the RIA presents a good analysis of the costs and benefits associated with the rule Proposed Rule. At worst, the RIA tends to underestimate the benefits of the new Proposed Rule and overestimate the costs.

Even if the Proposed Rule were to be put into effect, there are still substantial compliance costs for the oil and natural gas industries. These are likely underestimated in the RIA and could be as high as $3.521 million annually. This analysis suggests that these costs are likely, and could in and of themselves lead to reduced production on federal and Indian-owned leases. Overall, JDA estimates that 678 oil wells will either not be drilled or would be retired as the result of these increased costs. This could reduce production from federal leases by up to 768,266. *See* 2018 JDA report.

The Revised Rule Properly Accounts for New State Programs

Since the 2016 rule was promulgated, several state programs that address emissions from oil and natural gas production have been developed or become effective. This is important because while some groups allege a "regulatory gap" will leave federal sources unregulated, it is clear that many operations affected by the rule are, and will continue to also be, subject to emission controls through state programs, many of which are even more stringent than federal requirements. The current regulatory framework is sufficient to protect public health and the environment without duplicative regulation by BLM that exceeds the agency's statutory authority. In particular, we call BLM's attention to programs in California, Utah, and Colorado that were developed or implemented after the 2016 rule was finalized.

In California, the California Air Resources Board (CARB) recently established methane standards for oil and natural gas production facilities statewide.[22] The rule covers both new and existing sources, and is more stringent than federal requirements. The rule's expansive requirements cover a variety of equipment in both the upstream and midstream sectors, making BLM's requirements largely duplicative.

In Utah, a recently-finalized Permit-by-Rule (PBR) established registration requirements and comprehensive emission controls for all facilities subject to state or fee surface ownership.[23] Utah's complex checkerboard ownership means many locations with state or fee surface ownership have federal or tribal mineral ownership. According to the Utah Division of Oil Gas & Mining, there are 2,964 wells in Utah with either state or fee surface ownership and federal or tribal minerals. Since the PBR was not finalized until January of 2018, it was not contemplated by BLM in the development of the 2016 rule. Under the PBR, split-estate wells with federal minerals are and will remain under state jurisdiction from an emission control standpoint. Moreover, the primary producing region in Utah, the Uinta Basin, is heading towards a nonattainment classification under the 2015 ozone standard. With that final designation expected by the end of April, it would be inaccurate to claim federal wells in the region would be left "unregulated" and somehow outside of any regulatory framework. Rather, EPA, the Ute Indian Tribe, and the State of Utah will work together to address emissions in the region as they deem appropriate.

In Colorado, a recent rulemaking to implement EPA's Control Techniques Guidelines (CTGs) was finalized for the Denver-Julesburg (DJ) Basin.[24] Although much of the DJ Basin is fee mineral ownership, there are federal wells present in the Pawnee National Grassland and other areas around the region that are

[22] *Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities*, attached hereto as Appendix G.
[23] *PBR Eligibility Flowchart*. Utah Division of Air Quality, attached hereto as Appendix H.
[24] *See Colorado Air Quality Control Commission's 2017 Revisions to Regulation Number 7 – Oil and Gas Emissions Fact Sheet,* attached hereto as Appendix I.

impacted by the CTG rulemaking. Like the Utah PBR, the Colorado rulemaking was not finalized until well after the 2016 rulemaking, and serves as yet another example of state regulations that have arisen in recent years covering facilities in the so-called regulatory "gap." Moreover, as BLM has repeatedly recognized, the 2014 Regulation No. 7 rules in Colorado apply statewide, including existing oil and natural gas facilities subject to BLM regulation.

In North Dakota, the Department of Health (NDDOH) entered into a "global" consent decree with Bakken operators, many of which signed the agreement over the course of 2016. The consent decree was aimed to address what NDDOH asserted were field-wide deficiencies in emission control systems that were leading to excess emissions from controlled storage tank batteries. The terms of the consent decree focused on LDAR and controlling storage tank flash gas emissions. In total, 80% of non-tribal wells in North Dakota are covered by the consent decree, with another 10% covered under a Quality Assurance/Quality Control (QA/QC) Plan. Both the consent decree and QA/QC impose new emission controls on sources within the Bakken airshed that were not contemplated during the development of the 2016 waste prevention rule by virtue of the fact that the consent decree continues to be open and available for operators to sign.

While the regulatory landscape in the Bakken has changed since the Proposed Rule was developed in 2015, the lack of predictable and timely Rights-of-Way (ROWs) application processing remains a significant challenge to efficient operations in the state. Although perhaps not as acute as the problem was several years ago, federal and tribal ROWs can take 120 days to more than five years to process. This unacceptably long timeframe makes flaring extremely difficult to mitigate, since the most effective way to reduce flaring is through expanded infrastructure. In this respect, BLM itself remains a significant obstacle to reducing flaring rates in North Dakota.

In addition, the Bakken, as well as other basins, sometimes have checkerboard ownership of surface and mineral rights, meaning federal minerals may be interspersed with private or state minerals. The 2016 rule's onerous requirements do not exempt non-federal minerals that are unitized or communitized with federal minerals, meaning that private owners may be disadvantaged when their minerals are developed with federal minerals. North Dakota Petroleum Council's comments cover the unique regulatory landscape in the Bakken in greater detail, which Western Energy Alliance and IPAA endorse.

Recommended Technical Changes to the Revised Rule

While we support BLM's proposed revisions to the 2016 rule, we believe it would benefit from further technical changes to increase clarity for the regulated community.

In section 3179.2, we recommend that BLM limit the rule's applicability to oil and gas leases, units, and communitized areas with a minimum federal mineral interest threshold. There are situations around the West where due to checkerboard mineral interest, a communitized area may have a *de minimis* level of federal minerals, yet the Proposed Rule would apply (and subsequently impose significant economic burdens) on many private mineral owners. In places like Colorado, this also means unnecessary, duplicative regulation that provides no additional environmental or other benefit and adds to the administrative burden of operating in a communitized area. We believe that a 10% minimum federal mineral interest would sufficiently protect the federal mineral estate without harming private property owners. This minimum threshold is based on 43 C.F.R. § 3181.1 (*Preliminary consideration of unit agreement*), which states that "where Federal lands constitute less than 10% of the total unit area, a non-Federal unit agreement may be used." Based on existing law, 10% is an appropriate threshold for determining a sufficient federal nexus.

Section 3179.3 contains several definitions that appear redundant or potentially confusing. *Waste oil or gas, lost oil or gas, and avoidably/unavoidably lost oil or gas* appear to be defining essentially the same set of terms and conditions, regarding when a product can be deemed lost, and whether that loss should be considered royalty-bearing. We believe that *waste oil or gas* and *avoidably lost oil and gas* define the same concept, and as such, *waste oil or gas* is an unnecessary term that could potentially create confusion. Therefore, we recommend that BLM eliminate this term.

Regarding the definition of *avoidably lost*, it is unclear as to whether BLM is referring to losses upstream of the gas meter, downstream of the gas meter, or both. We suggest that BLM add clarifying language to this definition to minimize confusion.

For the definition of *unavoidably lost*, BLM includes "oil or gas that is lost because of line failures . . . ." As currently written, the definition of "line failures" is unclear and could be a potential cause for confusion. Line failure could mean a mechanical failure of the gas line, but it could also mean pressure constraints of the line itself. In other words, if attempting to put gas in the pipeline would result in a pressure exceedance, would that capacity constraint-driven situation be considered a failure of the line? We recommend that BLM clarify the term "line failure" to avoid confusion in this area.

We also recommend that BLM add "non-pipeline specification gas" to the definition of *unavoidably lost*. Some wells will produce associated gas with high levels of nitrogen, carbon dioxide, hydrogen sulfide, or other non-hydrocarbon gases that prevent it from being pipeline-ready at the wellhead. Wellsite-level gas treatment options may not necessarily exist or be economically feasible, given the complexity of the systems and volumes of gas involved. In those situations, we recommend that BLM exempt from royalty bearing provisions in the Proposed Rule the safe disposal of non-pipeline specification gas through either venting or flaring. Under such a situation, we believe it would be appropriate for lost gas from a gas well that has been deemed unavoidable to be vented if a control device is not already present.

Lastly, we recommend that BLM modify the strict limitations on venting to allow for venting from gas wells under certain circumstances, including for operational and safety concerns and where compliance would be unreasonably costly. Specifically, § 3179.6 requires operators of gas wells to flare rather than vent except for the enumerated circumstances. Gas wells, however, generally do not have flares, making compliance for gas wells impossible. The 2016 rule did not consider the economics of installing flares at all gas wells in order to comply with the venting prohibition in § 3179.6, meaning the economic burden of the no-venting standard is not accounted for either in the final rule or the Proposed Rule. Further, such a modification is consistent and within the scope of BLM's authority to impose "reasonable" waste prevention measures.

There are several other situations where the no-venting standard from gas wells is technically infeasible. Under the current rule, operators can only vent for non-routine maintenance. Pigging occurs frequently, but the preamble makes it clear that pigging is routine maintenance, and therefore gas lost during pigging must be flared. Pigging is a critical aspect of operational and infrastructure maintenance and provides significant safety and other benefits. Regular pigging should be encouraged, not discouraged. Accordingly, we encourage BLM to revise § 3179.6 to include pigging within "non-routine maintenance" or otherwise allow venting during pigging activity.

During an emergency, venting is only allowed if flaring is not feasible. But since gas wells do not typically have flares, they would be out of compliance with the venting prohibition in an emergency, despite not having the onsite equipment needed to comply. Among other things, this creates safety concerns. Retrofitting all gas wells with flares to avoid venting in these situations would add significant expense that was not contemplated in the 2016 rule. Lastly, as we noted in our comments to the 2016 rule, choosing flaring over venting as a matter of regulatory requirements, at its core, represents an air quality decision that lies outside of BLM's waste prevention authority under the MLA.

Conclusion

In closing, we reiterate the tremendous progress that America's oil and natural gas industry has made, and will continue to make, in addressing venting, flaring, and methane emissions. EPA's most recent data concerning such emissions demonstrates that despite a significant increase in production in recent years, emissions continue to decline, including specifically methane emissions from venting and flaring. In this respect, the fundamental premise upon which the 2016 rule was based is not accurate and warrants a reconsideration of the rule.

The 2016 rule exceeded BLM's authority, made numerous and fundamentally flawed assumptions in its assessment of both the cost of compliance to industry and the benefits derived from the rule, and was an unlawful, arbitrary and capricious agency action. Accordingly, BLM was required to make substantial revisions to that rule, and we believe the Proposed Rule is a vast improvement and consistent with the agency's statutory authority in most respects. Moreover, there is new data from state programs, and the effectiveness and economic impacts of the 2016 rule that require reconsideration. Lastly, while we believe the Proposed Rule is a substantial improvement that addresses many of the original rule's technical and legal deficiencies, it would benefit from several technical suggestions made here.

We appreciate the opportunity to provide BLM feedback and look forward to continuing our efforts to responsibly produce critically needed energy from our nation's public lands in an environmentally sensitive way that also maximizes the benefit to the taxpayers and broader economy.

Sincerely,

Daniel T. Naatz
Vice President, Federal Resources
IPAA

Kathleen Sgamma
President
Western Energy Alliance

APPENDIX A

IN THE UNITED STATES DISTRICT COURT

FOR THE DISTRICT OF WYOMING

STATE OF WYOMING and STATE OF MONTANA,

Petitioners,

STATE OF NORTH DAKOTA,

Intervenor-Petitioner,

vs.

UNITED STATES DEPARTMENT OF THE INTERIOR; SALLY JEWELL, in her official capacity as Secretary of the Interior; UNITED STATES BUREAU OF LAND MANAGEMENT; and NEIL KORNZE, in his official capacity as Director of the Bureau of Land Management,

Respondents,

WYOMING OUTDOOR COUNCIL, et al.; EARTHWORKS; STATE OF CALIFORNIA and STATE OF NEW MEXICO,

Intervenor-Respondents.

Case No. 2:16-CV-0285-SWS
(Lead Case)

<u>ORDER ON MOTIONS FOR PRELIMINARY INJUNCTION</u>

WESTERN ENERGY ALLIANCE, and the INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA,

Petitioners,

vs.

SALLY JEWELL, in her official capacity as Secretary of the United States Department of the Interior; and BUREAU OF LAND MANAGEMENT,

Respondents.

Case No. 2:16-CV-0280-SWS

This matter comes before the Court on the respective motions for preliminary injunction filed by the Petitioners and Intervenor-Petitioner (collectively, "Petitioners"): *Wyoming and Montana's Motion for Preliminary Injunction* (ECF No. 21),[1] *North Dakota's Motion for Preliminary Injunction* (ECF No. 39), and *Motion for Preliminary Injunction* filed by Petitioners Western Energy Alliance and the Independent Petroleum Association of America (ECF No. 12 in 16-CV-280). The Court, having considered the briefs and materials submitted in support of the motions and the oppositions thereto, having heard witness testimony and oral argument of counsel, and being otherwise fully advised, FINDS and ORDERS as follows:

BACKGROUND

On November 18, 2016, the Department of the Interior, Bureau of Land Management ("BLM") issued its final rule related to the reduction of waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on federal and Indian lands. *See* 81 Fed. Reg. 83,008 (Nov. 18, 2016), *Waste Prevention, Production Subject to Royalties, and Resource Conservation* (the "Final Rule" or "Rule"). By their motions, Petitioners request that the Court enjoin the Rule before it takes effect on January 17, 2017. Petitioners contend the Rule represents unlawful agency action because it exceeds BLM's statutory authority and is otherwise arbitrary and capricious.

[1] Unless otherwise noted, all filings referenced herein are from the docket in Case No. 2:16-CV-0285-S, which has been designated the Lead Case in these consolidated cases. (*See* ECF No. 23.)

During oil production, operators frequently dispose of the associated gas by venting or flaring if the gas cannot be easily captured for sale or used on-site. Associated gas is the natural gas that is produced from an oil well during normal production operations and is either sold, re-injected, used for production purposes, vented (rarely) or flared, depending on whether the well is connected to a gathering line or other method of capture. AR at 457 (BLM Regulatory Impact Analysis for the Final Rule ("RIA") at 11). In addition, emergency flaring or venting may be necessary for safety reasons. *Id*. Venting is the release of gases into the atmosphere, such as opening a valve on a tank to relieve tank pressure. Flaring is the controlled burning of emission streams through devices called flares or combustors, releasing the byproducts of that combustion into the atmosphere. While venting or flaring is sometime unavoidable, it is also sometimes done in the absence of infrastructure to transport the gas to market.

The Department of the Interior ("DOI") has regulated venting and flaring to prevent the waste of federal and Indian natural gas since 1979 when it issued Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases ("NTL-4A") (ECF No. 13-3), which the Waste Prevention Rule purports to replace. *See* 81 Fed. Reg. 83,008. NTL-4A prohibits venting and flaring of gas produced by oil wells, except when the gas is "unavoidably lost" as defined in NTL-4A and when the operator has sought and received BLM's approval to vent or flare. NTL-4A § IV.B. While unavoidably lost gas and gas vented or flared with BLM approval are exempted from royalties, gas that is "avoidably lost" – that is, gas lost due to an operator's negligence or failure to comply with the law – is subject to royalties. NTL-4A § I, II.A & C. NTL-4A also requires operators to measure and report each month the volume of gas sold, avoidably or unavoidably lost, vented or flared, or used for beneficial purposes. NTL-4A § V.

Over the past decade, oil and natural gas production in the United States, and on BLM-administered leases, has increased dramatically. AR 366 (81 Fed. Reg. at 83,104). Domestic production from over 96,000 federal oil and gas wells now accounts for 11 percent of the National's natural gas supply and 5 percent of its oil supply. In FY 2015, federal and Indian leases produced oil and gas valued at $20.9 billion, which generated $2.3 billion in royalties. *Id*. BLM represents that this increase in oil production has been accompanied by "significant and growing quantities of wasted natural gas." *Id*. According to the DOI's Office Natural Resources Revenue ("ONRR"), between 2009 and 2015, operators reported venting or flaring 2.7 percent of the natural gas produced on BLM-administered leases – purportedly enough natural gas to supply over 6.2 million households for one year. AR at 367 (81 Fed. Reg. at 83,015). According to the BLM, the problem of natural gas loss on BLM-administered leases is growing, evidenced by a 318 percent increase in reported volumes of flared oil-well gas and an increased number of operator applications to vent or flare royalty-free (between 2005, 2011, and 2014, the number of applications per year went from 50, to 622, to 1,248). *Id*.

While recognizing that flaring is sometimes unavoidable, the BLM determined the majority of flaring on its leases results from the rate of new well construction outpacing the existing infrastructure capacity. AR 5 (81 Fed. Reg. at 6619) (Proposed Rule). The other situation resulting in substantial flaring of associated gas on BLM-administered leases is when capture and processing infrastructure has not yet been built out. *Id*.

Flaring in these circumstances may be due to insufficient information about how much gas will be produced or to an operator's decision to focus on near-term oil production rather than investing in the gas capture and transmission infrastructure necessary to realize a profit from the associated gas. *Id*.

In December 2007, the Royalty Policy Committee issued a report recommending the BLM update its rules and identified specific actions to improve production accountability. AR 369 (81 Fed. Reg. at 83,107). In 2010, the DOI's Office of Inspector General and the U.S. Government Accountability Office ("GAO") both recommended that BLM's regulations regarding the royalty-free use of gas be updated to take advantage of new capture technologies. *Id*. The GAO estimated that the economically recoverable volume of natural gas being wasted through venting and flaring at oil and gas production sites on federal and Indian lands represents about $23 million in lost royalties. AR 448 (RIA at 2). The GAO determined that around 40 percent of the natural gas vented and flared on onshore federal leases could be economically captured using currently available technologies. AR 16 (81 Fed. Reg. at 6630). In 2016, the GAO issued another report finding that BLM's regulations failed to provide operators clear guidance on accounting for and reporting lost gas. AR 369 (81 Fed. Reg. at 83,017).

Concluding there is a "compelling need to update [NTL-4A's] requirements to make them clearer, more effective, and reflective of modern technologies and practices" (*id*.), BLM published the Proposed Rule on February 8, 2016 (81 Fed. Reg. 6616). The BLM accepted public comments, met with stakeholders and state regulators in states with significant federal oil and gas production, and discussed the Rule with personnel from the

Environmental Protection Agency ("EPA") on over 40 conference calls between January 2015 and October 2016. Only 9 months after publishing the Proposed Rule, BLM issued the Final Rule, with an effective date of January 17, 2017.

The Final Rule prohibits venting, except in certain limited situations such as emergencies or when flaring the gas is technically infeasible. 43 C.F.R. § 3179.6. Unlike the Proposed Rule's monthly flaring limits, the Final Rule adopts a more flexible capture-percentage approach, modeled on North Dakota's regulations, that requires operators to capture a certain percentage of the gas they produce each month, excluding specified volumes of allowable flared gas. 43 C.F.R. § 3179.7; AR 374-76 (81 Fed. Reg. at 83,023-24). Both the capture percentage and the flaring allowance phase in over a ten-year period. *Id*. The Final Rule allows operators to choose whether to comply with the capture targets on a lease-by-lease, county-wide, or state-wide basis. *Id*. at 83,023.

The Final Rule retains NTL-4A's distinction between avoidably and unavoidably lost gas – with royalties owed on the former but not the latter – but eliminates BLM's discretion to make unavoidable loss determinations on a case-by-case basis and instead lists twelve categories in which a loss is always considered unavoidable. 43 C.F.R. § 3179.4. Any gas flared in excess of the capture requirements is deemed an avoidable loss. *Id*. The Final Rule also requires operators to measure and report the amount of gas vented or flared above 50 million cubic feet per day. *Id*. § 3179.9. For leaks, the Final Rule requires that all operators inspect equipment twice a year and timely repair any leaks found. *Id*. §§ 3179.301-304. It also requires that operators update old and inefficient equipment that contributes to waste and minimize gas lost from storage vessels and during well maintenance, drilling, and completion. *Id*. §§ 3179.201-204.

BLM characterizes the environmental benefits of reducing the amount of methane and other air pollutants released into the atmosphere as ancillary to the Rule's primary purpose of waste prevention. As phrased by New Mexico's counsel during the hearing on Petitioners' motions, in these circumstances, "the product is also the pollutant." Thus, there can be no escaping the potential conflict between the BLM's regulation of waste and loss of gas and the EPA's regulation of air pollutants from oil and gas operations. In an attempt to alleviate the obvious problems potentially caused by overlapping regulations, the Rule incorporates the following provisions: (1) allows compliance with EPA's emissions requirements for *new or modified sources* to satisfy the requirements of the Rule when both EPA regulations and the Rule apply, 43 C.F.R. §§ 3179.102(b), 3179.301(j); (2) exempts from the Rule equipment covered by existing EPA regulations, *id*. §§ 3179.201(a)(2), 3179.202(a)(2), 3179.203(a)(2); and (3) allows a State or tribe to *request* a variance from provisions of the Rule, so long as state or tribal regulations are at least as effective as the Rule in reducing waste, *id*. § 3179.401. *See* AR 362, 365 (81 Fed. Reg. at 83,010, 83,013). The decision to grant or deny a variance is within the BLM's discretion and is not subject to review. *Id*. § 3179.401(b). If the BLM approves a variance, the State or tribal regulations can be enforced by the BLM; however, the State's or tribe's "own authority to enforce its regulation(s) or rule(s) *to be applied under the variance* would not be affected by the BLM's approval of a variance." *Id*. § 3179.401(f) (emphasis added).

Petitioners contend the Rule is, in actuality, an attempt by BLM to regulate air pollution which it lacks authority to do, and the Rule, at best, duplicates, and at worst, undermines, the agencies tasked by Congress with regulating air quality. Congress expressly delegated authority to the states and the EPA to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and productive capacity of its population." 42 U.S.C. § 7401(b)(1). The Clean Air Act ("CAA") provides that "[e]ach State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State[.]" *Id*. § 7407(a). Thus, in enacting the CAA, Congress established a comprehensive scheme for regulating air quality through "a cooperative-federalism approach" under which the EPA develops baseline air quality standards that the states implement and enforce. *Oklahoma v. U.S. E.P.A.*, 723 F.3d 1201, 1204 (10th Cir. 2013). Petitioners ask this Court to enjoin BLM from implementing the Rule because it exceeds BLM's authority by comprehensively regulating air quality and is arbitrary and capricious.

STANDARD OF REVIEW

To obtain a preliminary injunction, petitioners must show: "(1) a likelihood of success on the merits; (2) that they will [likely] suffer irreparable harm; (3) that the balance of equities tips in their favor; and (4) that the injunction is in the public interest." *Petrella v. Brownback*, 787 F.3d 1242, 1257 (10th Cir. 2015). *See also Glossip v. Gross*, 135 S. Ct. 2726, 2736 (2015) (quoting *Winter v. Natural Res. Def. Council, Inc.*, 555 U.S. 7, 20 (2008)). "[B]ecause a preliminary injunction is an extraordinary remedy, the movant's right to relief must be clear and unequivocal." *Fundamentalist Church of Jesus*

Christ of Latter-Day Saints v. Horne, 698 F.3d 1295, 1301 (10th Cir. 2012) (internal quotation marks and citation omitted); *see also Johnson & Johnson Vision Care, Inc. v. Reyes*, Nos. 15-4071, -4072, -4073, 2016 WL 7336568, at *3 (10th Cir. Dec. 19, 2016).

> The purpose of a preliminary injunction is merely to preserve the relative positions of the parties until a trial on the merits can be held. Given this limited purpose, and given the haste that is often necessary if those positions are to be preserved, a preliminary injunction is customarily granted on the basis of procedures that are less formal and evidence that is less complete than in a trial on the merits. A party thus is not required to prove his case in full at a preliminary-injunction hearing, and the findings of fact and conclusions of law made by a court granting a preliminary injunction are not binding at trial on the merits.

Univ. of Texas v. Camenisch, 451 U.S. 390, 395 (1981) (citations omitted). *See also Attorney General of Okla. v. Tyson Foods, Inc.*, 565 F.3d 769, 776 (10th Cir. 2009); *RoDa Drilling Co. v. Siegal*, 552 F.3d 1203, 1208 (10th Cir. 2009) (primary goal of preliminary injunction is to preserve the pre-trial status quo). The grant or denial of a preliminary injunction lies within the sound discretion of the district court. *Amoco Oil Co. v. Rainbow Snow*, 748 F.2d 556, 557 (10th Cir. 1984). *See also Dine Citizens Against Ruining Our Environment v. Jewell*, 839 F.3d 1276, 1281 (10th Cir. 2016).

DISCUSSION

Petitioners challenge the Rule pursuant to the Administrative Procedure Act, claiming the Rule should be set aside as arbitrary and capricious and in excess of the BLM's statutory authority. *See* 5 U.S.C. § 706(2)(A) & (C).[2]

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[2] The APA's scope of review provisions relevant here are:

> To the extent necessary to decision and when presented, the reviewing court shall decide all relevant questions of law, interpret constitutional and statutory provisions, and determine the meaning or applicability of the terms of an agency action. The reviewing court shall--

A. Likelihood of Success on Merits

Judicial review of agency action is governed by the standards set forth in § 706 of the APA, requiring the reviewing court to engage in a "substantial inquiry." *Olenhouse v. Commodity Credit Corp.*, 42 F.3d 1560, 1573-74 (10th Cir. 1994) (citing *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402 (1971)). While an agency's decision is entitled to a "presumption of regularity," the presumption does not shield the agency from a "thorough, probing, in-depth review." *Id*. at 1574. "[T]he essential function of judicial review is a determination of (1) whether the agency acted within the scope of its authority, (2) whether the agency complied with prescribed procedures, and (3) whether the action is otherwise arbitrary, capricious or an abuse of discretion." *Id*. "Determination of whether the agency acted within the scope of its authority requires a delineation of the scope of the agency's authority and discretion, and consideration of whether on the facts, the agency's action can reasonably be said to be within that range." *Id*.

Under the arbitrary and capricious standard, a court must ascertain "whether the agency examined the relevant data and articulated a rational connection between the facts found and the decision made." *Id*. The agency must provide a reasoned basis for its

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* * *
(2) hold unlawful and set aside agency action, findings, and conclusions found to be--
(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;
* * *
(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right;
* * *
In making the foregoing determinations, the court shall review the whole record or those parts of it cited by a party, and due account shall be taken of the rule of prejudicial error."

5 U.S.C. § 706.

action and the action must be supported by the facts in the record. *Id.* at 1575. Agency action is arbitrary if not supported by "substantial evidence" in the administrative record. *Olenhouse*, 42 F.3d at 1575; *Pennaco Energy, Inc. v. U.S. Dep't of Interior*, 377 F.3d 1147, 1156 (10th Cir. 2004). "Substantial evidence is such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Pennaco Energy,* 377 F.3d at 1156 (quoting *Doyal v. Barnhart*, 331 F.3d 758, 760 (10th Cir. 2003)). "Because the arbitrary and capricious standard focuses on the rationality of an agency's decisionmaking process rather than on the rationality of the actual decision, '[i]t is well-established that an agency's action must be upheld, if at all, on the basis articulated by the agency itself.'" *Olenhouse*, 42 F.3d at 1575 (quoting *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Ins. Co.*, 463 U.S. 29, 50 (1983)).

1. BLM's Authority to Promulgate the Rule

"It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress." *Bowen v. Georgetown Univ. Hosp*., 488 U.S. 204, 208 (1988). "Regardless of how serious the problem an administrative agency seeks to address, [] it may not exercise its authority 'in a manner that is inconsistent with the administrative structure that Congress enacted into law.'" *Food and Drug Admin. v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 125 (2000) (quoting *ETSI Pipeline Project v. Missouri*, 484 U.S. 495, 517 (1988)). Accordingly, an "essential function" of a court's review under the APA is to determine "whether an agency acted within the scope of its authority." *WildEarth Guardians v. U.S. Fish and Wildlife Serv.*, 784 F.3d 677, 683 (10th Cir. 2015).

Where a case involves an administrative agency's assertion of authority to regulate a particular activity pursuant to a statute that it administers, the court's analysis is governed by *Chevron U.S.A. Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837 (1984). *See Brown & Williamson*, 529 U.S. at 132.

> Under *Chevron*, a reviewing court must first ask whether Congress has directly spoken to the precise question at issue. If Congress has done so, the inquiry is at an end; the court must give effect to the unambiguously expressed intent of Congress. But if Congress has not specifically addressed the question, a reviewing court must respect the agency's construction of the statute so long as it is permissible. Such deference is justified because the responsibilities for assessing the wisdom of such policy choices and resolving the struggle between competing views of the public interest are not judicial ones, and because of the agency's greater familiarity with the ever-changing facts and circumstances surrounding the subjects regulated[.]

Id. (internal quotation marks and citations omitted). Unlike the situation in *State of Wyoming, et al. v. Dep't of Interior*, No. 15-CV-043-S (June 21, 2016) (setting aside BLM's final rule related to hydraulic fracturing), Congress has not directly announced that the precise activity in question not be subject to federal regulation. Absent clear expression of Congressional intent, the Court must proceed to the second step of the *Chevron* abyss.[3]

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[3] As a sister federal district court has recently observed:

> *Chevron's* second step is the easier one to describe, because it is all but toothless: if the agency's decision makes it to step two, it is upheld almost without exception. *See* Ronald M. Levin, *The Anatomy of Chevron: Step Two Reconsidered*, 72 CHI. KENT L.REV. 1253, 1261 (1997) ("[T]he Court has never once struck down an agency's interpretation by relying squarely on the second *Chevron* step." (footnote omitted)); Jason J. Czarnezki, *An Empirical Investigation of Judicial Decisionmaking, Statutory Interpretation, and the Chevron Doctrine in Environmental Law*, 79 U. COLO. L.REV. 767, 775 (2008) ("Due to the difficulty in defining step two, courts rarely strike down agency action under step two, and the Supreme Court has done so arguably only twice."). Courts essentially never conclude that an agency's interpretation of an unclear statute is unreasonable.

Jarita Mesa Livestock Grazing Ass'n v. U.S. Forest Serv., 140 F. Supp. 3d 1123, 1168-69 (D.N.M. 2015).

The Mineral Leasing Act of 1920 ("MLA") creates a program for leasing mineral deposits on federal lands.[4] Congress authorized the Secretary "to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of the [the MLA]." 30 U.S.C. § 189. "The purpose of the Act is to promote the orderly development of oil and gas deposits in publicly owned lands of the United States through private enterprise." *Geosearch, Inc. v. Andrus*, 508 F. Supp. 839, 842 (D. Wyo. 1981) (citing *Harvey v. Udall*, 384 F.2d 883 (10th Cir. 1967)). *See also Arkla Exploration Co. v. Texas Oil & Gas Corp.*, 734 F.2d 347, 358 (8th Cir. 1984) ("broad purpose of the MLA was to provide incentives to explore new, unproven oil and gas areas through noncompetitive leasing, while assuring through competitive bidding adequate compensation to the government for leasing in producing areas").[5]

Specifically, for oil and gas leasing, the MLA, *inter alia,* establishes terms of the lease and royalty and rental amounts (30 U.S.C. §§ 223, 226(d)&(e)), requires the lessee to "**use all reasonable precautions to prevent waste of oil or gas developed in the land**" (*id*. § 225) (emphasis added), authorizes the Secretary of Interior to lease all public lands subject to the Act for oil and gas development (*id*. § 226(a)), directs the Secretary to regulate *surface*-disturbing activities (*id*. § 226(g)), and allows for the establishment of cooperative development plans to conserve oil and gas resources (*id*. § 226(m)). Section 187 confirms the BLM's authority to issue regulations to carry out the MLA's waste prevention objectives: "Each lease shall contain provisions for the purpose of insuring

[4] The MLA applies to deposits of coal, phosphate, sodium, potassium, oil, oil shale, gilsonite, or gas, and virtually all lands containing such deposits owned by the United States. 30 U.S.C. § 181.

[5] The Indian Mineral Leasing Act ("IMLA"), generally, grants the Secretary broad regulatory jurisdiction over oil and gas development and operations on Indian lands. 25 U.S.C. § 396d.

the exercise of reasonable diligence, skill and care in the operation of said property" and "a provision that **such rules . . . for the prevention of undue waste as may be prescribed by said Secretary** shall be observed." (Emphasis added.)

The Federal Oil and Gas Royalty Management Act of 1982 ("FOGRMA"), 30 U.S.C. § 1751, creates a thorough system for collecting and accounting for federal mineral royalties. FOGRMA reiterates Congress' concern about wasted oil and gas: "Any lessee is liable for royalty payments on oil or gas lost or wasted from a lease site when such loss or waste is due to negligence on the part of the operator of the lease, or due to the failure to comply with any rule or regulation, order or citation issued under this chapter or any mineral leasing law." 30 U.S.C. § 1756. Like the MLA, FOGRMA contains a broad grant of rulemaking authority to achieve its objectives. 30 U.S.C. § 1751 ("The Secretary shall prescribe such rules and regulations as he deems reasonably necessary to carry out this chapter.").

The terms of the MLA and FOGRMA make clear that Congress intended the Secretary, through the BLM, to exercise its rulemaking authority to prevent the waste of federal and Indian mineral resources and to ensure the proper payment of royalties to federal, state, and tribal governments.[6] "[T]he delegation of general authority to promulgate regulations extends to all matters 'within the agency's substantive field.' Because 'the whole includes all of its parts,' courts need not try to discern whether '*the particular issue* was committed to agency discretion.'" *Helfrich v. Blue Cross & Blue Shield Ass'n*, 804 F.3d 1090, 1109 (10th Cir. 2015) (quoting *City of Arlington v. F.C.C.*,

[6] Petitioners do not challenge BLM's authority to regulate waste and promulgate rules governing royalty payments.

133 S. Ct. 1863, 1874 (2013)). The question here, then, is not whether the MLA and FOGRMA specifically grant BLM the authority to regulate venting, flaring, and equipment leaks, but rather whether they unambiguously grant BLM authority to regulate the development of federal and Indian oil and gas resources *for the prevention of waste*. The answer to that question, largely undisputed by Petitioners, is "yes." "The [MLA] was intended to promote wise development of these natural resources and to obtain for the public a reasonable financial return on assets that 'belong' to the public." *California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961).

The rub here, however, is whether the Rule, or at least certain provisions of the Rule, was promulgated *for the prevention of waste* or instead for the *protection of air quality*, which is expressly within the "substantive field" of the EPA and states pursuant to the Clean Air Act. The BLM argues the Rule's benefits to air quality do not undercut its waste prevention purpose – to be sure, a regulation that prevents wasteful losses of natural gas necessarily reduces emissions of that gas. The Court further agrees that the BLM is entitled to deference regarding the determination of how best to minimize losses of gas due to venting, flaring, and leaks, and incentivize the capture and use of produced gas. In doing so, the Federal Land Policy and Management Act ("FLPMA") arguably directs BLM to consider any impact to "the quality of . . . air and atmospheric . . . values." 43 U.S.C. § 1701(1)(8).[7] While the statutory obligations of two separate

[7] The Court does not agree with BLM's suggestion that FLPMA grants it broad authority to promulgate its own regulations directed at air quality control. *See* Fed. Resp'ts' Br. at 25 (ECF No. 70 at 38). FLPMA primarily establishes congressional policy that the Secretary manage the public lands under principles of multiple use and sustained yield. At its core, FLPMA is a land use planning statute. *See* 43 U.S.C. § 1712; *Rocky Mtn. Oil and Gas Ass'n v. Watt*, 696 F.2d 734, 739 (10th Cir. 1982) ("FLPMA contains comprehensive inventorying and land use

agencies may overlap, the two agencies must administer their obligations to avoid inconsistencies or conflict. *See Massachusetts v. E.P.A.*, 549 U.S. 497, 532 (2007).

As stated above, an administrative agency may not exercise its authority "in a manner that is inconsistent with administrative structure that Congress enacted into law." *Brown & Williamson Tobacco Corp.*, 529 U.S. at 125. Further, "the meaning of one statute may be affected by other Acts, particularly where Congress has spoken subsequently and more specifically to the topic at hand." *Id*. at 133. When enacting the Clean Air Act in 1970, Congress directly addressed the issue of air pollution and created a **comprehensive** scheme for its prevention and control.

> The Clean Air Act, 42 U.S.C. § 7401 *et seq*., enacted in 1970, is a comprehensive federal law that regulates air emissions under the auspices of the United States Environmental Protection Agency ("EPA"). Congress enacted the law in response to evidence of the increasing amount of air pollution created by the industrialization and urbanization of the United States and its threat to public health and welfare. 42 U.S.C. § 7401(a)(2). The Clean Air Act states that **air pollution prevention and control is the primary responsibility of individual states and local governments** but that federal financial assistance and leadership is essential to accomplish these goals. *Id*. § 7401(a)(3)-(4). Thus, it employs a "**cooperative federalism**" structure under which the federal government develops baseline standards that the **states individually implement and enforce**. *GenOn REMA, LLC v. EPA*, 722 F.3d 513, 516, No. 12–1022, 2013 WL 3481486, at *1 (3d Cir. July 12, 2013). In so doing, states are expressly allowed to employ standards more stringent than those specified by the federal requirements. 42 U.S.C. § 7416. The Clean Air Act makes the EPA responsible for developing acceptable national ambient air quality standards

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planning provisions to ensure that the 'proper multiple use mix of retained public lands' be achieved"); *Norton v. S. Utah Wilderness Alliance*, 542 U.S. 55, 57 (FLPMA establishes a dual regime of inventory and planning); *Klamath Siskiyou Wildlands Center v. Boody*, 468 F.3d 549, 555 (9th Cir. 2006) (FLPMA establishes requirements for land use planning on public land). *See also* "Memorandum of Understanding Among the U.S. Dep't of Agric., U.S. Dep't of Interior, and U.S. Envt. Prot. Agency, Regarding Air Quality Analyses and Mitigation for Federal Oil and Gas Decisions through the NEPA Process at 7 (June 23, 2011) (describing BLM's authority over air quality as limited to developing land use plans and providing for compliance with state and Federal pollution control laws, including the CAA), available at https://www.doi.gov/sites/doi.gov/files/migrated/news/pressreleases/upload/29704-Joint-MOU-Air-Quality-FINAL.pdf.

> ("NAAQS"), which are meant to set a uniform level of air quality across the country in order to protect the populace and the environment. *Id.* § 7409(b)(1). Before such levels are adopted or modified by the EPA, "a reasonable time for interested persons to submit written comments" must be provided. *Id.* § 7409(a)(1)(B). The EPA itself does not typically regulate individual sources of emissions. Instead, decisions regarding how to meet NAAQS are left to individual states. *Id.* § 7410(a)(1). Pursuant to this goal, each state is required to create and submit to the EPA a State Implementation Plan ("SIP") which provides for implementation, maintenance, and enforcement of NAAQS within the state. *Id.* All SIPs must be submitted to the EPA for approval before they become final, and once a SIP is approved, "its requirements become federal law and are fully enforceable in federal court." *Her Majesty the Queen in Right of the Province of Ontario v. Detroit*, 874 F.2d 332, 335 (6th Cir.1989) (citing 42 U.S.C. § 7604(a)). States are tasked with enforcing the limitations they adopt in their SIPs. They must regulate all stationary sources located within the areas covered by the SIPs, 42 U.S.C. § 7410(a)(2)(C), and implement a mandatory permit program that limits the amounts and types of emissions that each stationary source is allowed to discharge, id. §§ 7661a(d)(1), 7661c(a). "[E]ach permit is intended to be a source-specific bible for Clean Air Act compliance containing in a single, comprehensive set of documents, all [Clean Air Act] requirements relevant to the particular polluting source." *North Carolina, ex rel. Cooper v. Tenn. Valley Auth.*, 615 F.3d 291, 300 (4th Cir.2010) (internal quotation marks omitted).

Bell v. Cheswick Generating Station, 734 F.3d 188, 190 (3d Cir. 2013) (emphasis added).

Although the Rule's overlapping regulations themselves appear consistent with EPA regulations,[8] the Rule has potential conflict and inconsistency with the implementation and enforcement provisions of the CAA. The Rule upends the CAA's cooperative federalism framework and usurps the authority Congress expressly delegated under the CAA to the EPA, states, and tribes to manage air quality. *See Texas v. U.S. EPA*, 690 F.3d 670, 674-75 (5th Cir. 2012) (discussing the CAA's regulatory design which requires cooperation between federal government and states in administering the

[8] Indeed, BLM harmonized the definitions of certain terms with the overlapping EPA definitions in response to public comments, *see* 81 Fed. Reg. at 83,047, and certain other provisions of the Rule are taken directly from EPA air control requirements under 40 C.F.R. subparts OOOO or OOOOa.

CAA). For example, the Rule recognizes compliance with the EPA's oil and gas production facility performance standards as compliance with the Rule; but no similar automatic compliance recognition exists for those very same standards if the EPA has approved enforcement authority to a state. *See* AR 365 (81 Fed. Reg. at 83,013). Instead, the Rule requires states and tribes to request a variance from a particular BLM regulation, placing the burden on the states and tribes to prove its already-EPA approved rule "would perform at least as well as the BLM provision to which the variance would apply, in terms of reducing waste of oil and gas, reducing environmental impacts from venting and/or flaring of gas, and ensuring the safe and responsible production of oil and gas." *Id.* The Rule further empowers the BLM to enforce the state or tribal rules if the variance is granted (*id.*), creating the potential for inconsistent or conflicting enforcement.

The Rule also conflicts with the statutory scheme under the CAA for regulating air emissions from oil and natural gas sources, particularly by extending its application of overlapping air quality provisions to existing facilities, which the EPA itself has not yet done. *See* 42 U.S.C. § 7411(d) ("[t]he Administrator shall prescribe regulations which shall establish a procedure . . . under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant . . . and (B) provides for the implementation and enforcement of such standards of performance"). While the EPA has begun the rulemaking process for regulation of existing sources under the CAA,[9] the BLM has hijacked the EPA's authority under the guise of waste management.[10] AR 371 (81 Fed. Reg. at 83,019).

Of course, BLM has authority to promulgate and impose regulations which may have air quality benefits and even overlap with CAA regulations *if* such rules are independently justified as waste prevention measures pursuant to its MLA authority. "[A]n agency may not bootstrap itself into an area in which it has no jurisdiction." *Adams Fruit Co., Inc. v. Barrett*, 494 U.S. 638, 650 (1990) (internal quotation marks and citation omitted). In other words, the BLM cannot use overlap to justify overreach. Petitioners contend the Rule is fundamentally an air quality regulation, not a resource conservation rule.

Portions of BLM's stated rationale for the Rule undermine Respondents' insistence that the Rule is foremost a waste prevention regulation that simply has incidental benefits to air quality: "wasted gas . . . contribute[s] to regional and global air pollution problems of smog, particulate matter, and toxics, [and] vented or leaked gas contributes to climate change, because the primary constituent of natural gas is methane, an especially powerful greenhouse gas (GHG), with climate impacts roughly 25 times those of carbon dioxide (CO_2), if measured over a 100-year period, or 86 times those of

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[9] On June 3, 2016, the EPA issued a final rule entitled "Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources" published in the Federal Register at 81 Fed. Reg. 35824. A challenge to EPA's Rules has been filed in the United States Court of Appeals for the District of Columbia Circuit. *See North Dakota v. U.S. EPA*, 16-1242.

[10] One could also construe BLM's incorporation of EPA's air quality rules (OOOO and OOOOa) as doubling down in the event the challenge to EPA's final rule is successful. The BLM arrogantly justifies the Rule's application of overlapping air quality regulations to existing sources by expressing its dissatisfaction with the length of the CAA process and the uncertainty of the resulting outcome. *See* 81 Fed. Reg. 83,019 ("Given the length of this [CAA] process and the uncertainty regarding the final outcomes, and in light of the BLM's independent statutory mandate to prevent waste from Federal and Indian oil and gas leases based on information currently available, the BLM has determined that it is necessary and prudent to update and finalize this regulation at this time.").

CO_2, if measured over a 20-year period" (AR 361, 81 Fed. Reg. at 83,009); benefits of the Rule measured as cost savings to industry and "the environmental benefits of reducing the amount of methane [] and other air pollutants released into the atmosphere" (*id.* at 366, 83,014); "the waste of natural gas also imposes public health and environmental costs, in the form of air pollution, such as . . . emissions of methane, a powerful contributor to global warming and a primary target for reduction under the President's Climate Action Plan" (*id.*); "[a]bsent stronger provisions to reduce natural gas waste on Federal lands, the avoidable loss of gas will continue to threaten climate stability and undermine respiratory and cardiovascular health" (*id.* at 366-67, 83,014-15). Nevertheless, at this point, the Court cannot conclude that the provisions of the Rule which overlap with EPA/state air quality regulations promulgated under CAA authority lack a legitimate, independent waste prevention purpose or are otherwise so inconsistent with the CAA as to exceed BLM's authority and usurp that of the EPA, states, and tribes. Thus, Petitioners have not shown a clear and unequivocal right to relief.

2. Whether the Rule is Arbitrary and Capricious

Because the process by which an agency reaches a result must be "logical and rational," agency action must rest "on a consideration of the relevant factors." *Michigan v. E.P.A.*, 135 S. Ct. 2699, 2706 (2015). Agency action may be arbitrary and capricious where it has relied on factors which Congress did not intend the agency to consider. *National Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 658 (2007). Taking at face value BLM's assertion that the Rule "aims to reduce the waste of natural gas," the cost-benefit analysis should have been considered primarily in terms of waste prevention and not air pollution. *See* AR 360, 366 (81 Fed. Reg. at 83,008, 83,014). Instead, the BLM appears to be propping up the benefits of the Rule in air quality terms.

The BLM estimates the net benefits of the Rule outweigh its costs by "a significant margin," producing net benefits ranging from $46 million to $204 million per year depending on the discount rate used. AR 365 (81 Fed. Reg. at 83,013). Again, depending on the discount rate used, BLM estimates costs (largely for engineering compliance) will range from $110 million to $279 million per year. *Id*. BLM estimates the Rule will result in monetized benefits of $209-$403 million per year. Of the total benefits, however, $189-$247 million is attributable to the environmental benefit of reducing the amount of methane released into the atmosphere, and the remainder of $20-$157 million to the costs savings that industry will receive from the recovery and sale of natural gas. AR 366 (81 Fed. Reg. 83,014). *See also* RIA at 5. BLM estimates the Rule will produce additional royalties of $3-$14 million per year (depending on the discount rate).[11] *Id*. Thus, the Rule only results in a "net benefit" if the "social cost of methane" is allowed to be factored into the analysis. RIA at 5-6.

The Court questions whether the "social cost of methane" is an appropriate factor for BLM to consider in promulgating a resource conservation rule pursuant to its MLA authority. Moreover, it appears the asserted cost benefits of the Rule are predominately based upon the emission reductions, which is outside of BLM's expertise, and not attributable to the purported waste prevention purpose of the Rule. The question then

[11] The total production of oil and gas in FY 2015 from federal and tribal leases generated over $2.3 billion in royalties. AR 361 (81 Fed. Reg. at 83,009).

becomes whether the Rule is arbitrary and capricious because it imposes significant costs to achieve *de minimus* benefits. *See Michigan v. EPA*, 135 S. Ct. at 2707 ("Consideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages *and* the disadvantages of agency decisions."). The BLM contends compliance costs are not the appropriate measure of the Rule's reasonableness, and it is appropriate to consider the environmental and related social benefits of the Rule. Again, though the Court has concerns in this regard, it cannot conclude at this point that the Rule is arbitrary and capricious and Petitioners have shown a clear and unequivocal right to relief. *See National Cable & Telecommunications Ass'n v. Brand X Internet Servs.*, 545 U.S. 967, 981 (2005) (under step two of *Chevron,* court required to accept agency's construction of statute even if agency's reading differs from what court believes is best interpretation).

B. Irreparable Harm

The irreparable harm factor requires a party "seeking preliminary relief to demonstrate that irreparable injury is *likely* in the absence of an injunction." *Winter v. Natural Res. Def. Council, Inc.*, 555 U.S. 7, 22 (2008) (emphasis in original). To satisfy the irreparable harm requirement, a movant must demonstrate "a significant risk that he or she will experience harm that cannot be compensated after the fact by monetary damages." *RoDa Drilling Co. v. Siegal*, 552 F.3d 1203, 1210 (10th Cir. 2009) (quoting *Greater Yellowstone Coal. v. Flowers*, 321 F.3d 1250, 1258 (10th Cir. 2003)). A court must further assess "whether such harm is likely to occur before the district court rules on the merits." *Id*. (quoting *Greater Yellowstone Coal.*, 321 F.3d at 1260). "[T]he party seeking injunctive relief must show that the injury complained of is of such imminence that there is a clear and present need for equitable relief to prevent irreparable harm." *Heideman v. South Salt Lake City*, 348 F.3d 1182, 1189 (10th Cir. 2003) (internal quotation marks and citation omitted).

The State Petitioners assert irreparable harm resulting from the Rule's infringement on their sovereign authority and interests in administering their own regulatory programs governing air emissions from oil and gas production. However, State regulations will continue to apply to oil and gas operations in tandem with the Rule, just as operators are currently subject to both States' rules and NTL-4A. Further, the Rule requires BLM to coordinate with States when BLM action to enforce the Rule could adversely affect production of state or private mineral interests. *See* 43 C.F.R. § 3179.12. While the overlapping and potentially conflicting regulations may interfere with the implementation and enforcement rights Congress gave to the states under the CAA, which would likely occur immediately upon the Rule becoming effective, the Court cannot say there is no legitimate, independent waste prevention purpose in those regulations, which is within the BLM's statutory authority to regulate. Unlike the situation in *State of Wyoming, et al. v. Dep't of Interior*, No. 15-CV-043-S (Sept. 30, 2015) (Order on Motions for Preliminary Injunction), there has been no express announcement by Congress that the activities in question are not subject to federal regulation. Because the overlapping regulations themselves appear consistent with the State Petitioners' own regulations, albeit with broader application to existing sources, the Court is not convinced the BLM's exercise of overlapping authority will interfere with the States' sovereign interests in, and public policies related to, regulation of air emissions to the point of causing irreparable harm to the State Petitioners pending this Court's ruling on the merits.

The State Petitioners further contend irreparable harm through economic losses in the form of decreased tax revenue and lost jobs from delay in production and avoidance of development in states with significant federal land. To be sure, to the extent such losses would be permanent, they are irreparable because the States cannot recover money damages from the federal government. *See Crowe & Dunlevy, P.C. v. Stidham*, 640 F.3d 1140, 1157 (10th Cir. 2011) (explaining that while economic loss is usually insufficient to constitute irreparable harm, "imposition of money damages that cannot later be recovered for reasons such as sovereign immunity constitutes irreparable injury"). However, the Court finds the States' assertion of economic loss to be speculative and unsupported by facts. "To constitute irreparable harm, an injury must be certain, great, actual and not theoretical." *Heideman*, 348 F.3d at 1189 (internal quotation and citation omitted).

Again, Petitioners have not shown BLM's overlapping "air quality" regulations to be inconsistent or significantly more onerous than the EPA's or the States' own regulations. Neither have Petitioners shown the Rule's application will hamper or delay oil and gas production to the extent of causing imminent irreparable harm to the States' economic interests. Moreover, the Rule provides for several economic exemptions where an operator shows, and BLM concurs, that compliance with the Rule's requirements "would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease." *See, e.g.,* 43 C.F.R. § 3179.102(c) (exemption from requirements related to well completion); § 3179.201(b)(4) (exemption from pneumatic controllers requirements); § 3179.202(f) (exemption from pneumatic diaphragm pump requirements); § 3179.203(c)(3) (exemption from storage vessels requirement); § 3179.303(c) (operator may request approval of a leak detection program that does not meet criterion specific in § 3179.303(b)).

The Industry Petitioners assert irreparable harm through: (1) costs of compliance; (2) disclosure of proprietary, confidential, and competitive information; and (3) payment of royalties on gas BLM has characterized as "avoidably lost." First, Industry Petitioners cannot demonstrate irreparable harm based on paying royalties on gas the Rule deems "avoidably lost" because, if Petitioners ultimately prevail on the merits and the Court sets aside the Rule's royalty requirements, any overpaid royalties can be recovered from the agency. *See* 30 U.S.C. § 1721a.

Additionally, though there are undoubtedly certain and significant compliance costs attached to the Rule, which are unrecoverable from the federal government, the Court is not convinced that these costs are of "such imminence that there is a clear and present need for equitable relief to prevent irreparable harm." Industry Petitioners point to a statement in the Regulatory Impact Analysis that the "requirements to replace existing equipment would necessitate *immediate* expenditures." RIA at 4 (emphasis added). However, many of the Rule's requirements, including equipment replacement, do not take effect for a year. *See, e.g.,* 43 C.F.R. § 3179.7 (gas capture); § 3179.201 (pneumatic controllers); § 3179.202 (pneumatic diaphragm pumps); § 3179.203 (storage vessels). And any alleged expenses associated with "immediate action to begin Rule implementation and compliance planning" are simply too uncertain and speculative to constitute irreparable harm. (*See* Sgamma Dec. ¶ 8; Industry Pet'rs' Br. at 49, Ex. 5.)

Industry Petitioners further argue the Rule will cause irreparable harm because it requires their members to provide to BLM information they consider proprietary, confidential, and competitive without assurances BLM can or will protect this information from disclosure. "A trade secret once lost is, of course, lost forever." *FMC Corp. v. Taiwan Tainan Giant Indus. Co., Ltd.*, 730 F.2d 61, 63 (2nd Cir. 1984). The only specific example offered by Petitioners is the information required in the waste minimization plan that must accompany an APD, including anticipated production from a proposed well, the expected production decline curve of oil and gas from the well, and the expected Btu value for gas production from the proposed well. *See* 43 C.F.R. § 3162.3-1(j)(2)(i)-(iv). In response to a public comment requesting disclosure of waste minimization plans, BLM stated it will publicly post the waste minimization plans accompanying the APDs, "subject to any protections for confidential business information." AR 395 (81 Fed. Reg. at 83,043). The BLM further stated: "operators routinely provide information to the BLM that they consider confidential; if they indicate on the Sundry Notice that the information is considered confidential, the BLM will handle the information in accordance with applicable regulations." *Id*. at 403, 83,051. The Industry Petitioners have not shown that BLM's existing confidentiality protections are inadequate to protect the information required in the waste minimization plans. *See*

§§ 2.26-2.36. Thus, the Court finds Petitioners have failed to establish that irreparable injury is likely in the absence of an injunction.

C. Balance of Equities and Public Interest

Having concluded Petitioners have not clearly and unequivocally established a likelihood of success on the merits and irreparable harm, the Court need not address the remaining factors that must be shown to obtain a preliminary injunction. Still, the Court feels compelled to briefly touch upon these factors with a few observations.

The third preliminary injunction factor requires the Court to determine whether the threatened injury to the movants outweighs the injury to the opposing party under the injunction. *Awad v. Ziriax*, 670 F.3d 1111, 1125 (10th Cir. 2012); *Sierra Club, Inc. v. Bostick*, 539 F. App'x 885, 889 (10th Cir. 2013). The Court finds the balance of harms in this case does not tip decidedly in either side's favor. Though Petitioners have not shown a likelihood of irreparable harm justifying an injunction, neither have Respondents shown substantial harm if an injunction were granted. BLM has been regulating oil and gas waste pursuant to NTL-4A for 30 years. The asserted need to update BLM's rules to account for technological advances does not seem so pressing that appreciable harm will result to BLM if the Rule's effective date is delayed pending this Court's ruling on the merits. The asserted benefits of the Rule are found largely in the social benefits of reducing emissions of methane and other pollutants, which is already subject to EPA and state regulations.

Finally, public interest factors also support both sides of the issue. The public interest is served by preserving the status quo, particularly where the balance of harms does not tip decidedly in either side's favor. *See O Centro Espirita Beneficiente Uniao Do Vegetal v. Ashcroft*, 389 F.3d 973, 1001-02 (10th Cir. 2004) (en banc) (Seymour, J., concurring in part, dissenting in part). A preliminary injunction would not be adverse to the public interest in resource conservation because the BLM already has regulations in place to prevent waste and many of the Rule's provisions do not take effect for a year; nor would an injunction be adverse to the public interest in clean air because the EPA and State Petitioners already regulate emissions from oil and gas production, albeit not as broadly as the Rule contemplates. A preliminary injunction would also sidestep the costly implementation of duplicative and potentially unlawful regulations. So, while the Rule itself is arguably in the public's interest in resource conservation and air quality, a preliminary injunction would not necessarily be adverse to those interests.

CONCLUSION

Under the MLA, Congress has vested the Secretary with the authority to prescribe rules for the prevention of undue waste of mineral resources. Having done so, at this stage and applying the deference as required under *Chevron*, this Court cannot conclude the Rule enacted exceeds the Secretary's authority or is arbitrary and capricious. Petitioners have not established their right to relief is clear and unequivocal. Petitioners have failed to establish all four factors required for issuance of a preliminary injunction, so their respective motions must be denied. The Court will, however, entertain Respondents' suggestion of an expedited briefing schedule on the merits. THEREFORE, it is hereby

ORDERED that *Wyoming and Montana's Motion for Preliminary Injunction* (ECF No. 21), *North Dakota's Motion for Preliminary Injunction* (ECF No. 39), and the *Motion for Preliminary Injunction* filed by Petitioners Western Energy Alliance and the Independent Petroleum Association of America (ECF No. 12 in 16-CV-280) are **DENIED**; it is further

ORDERED that Respondents shall lodge the administrative record on or before **February 21, 2017**. Petitioners shall file their opening briefs within thirty (30) days after the date on which the record is lodged. Respondents shall file their briefs within twenty (2) days after service of the Petitioners' briefs. Reply briefs shall be filed within ten (10) days after service of the Respondents' briefs. The parties shall otherwise comply with U.S.D.C.L.R. 83.6.

DATED this 16th day of January, 2017.

Scott W. Skavdahl
United States District Judge

APPENDIX B

April 22, 2016

via e-filing at www.regulations.gov

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

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

To Whom It May Concern:

I. INTRODUCTION

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

The Associations

The Independent Petroleum Association of America represents the thousands of independent oil and natural gas exploration and production companies, as well as the service and supply industries that support their efforts.. Independent producers drill about 95 percent of American oil and natural gas wells, produce about 54 percent of American oil, and more than 85 percent of American natural gas.

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

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

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

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

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

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

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

II. GENERAL LEGAL AND POLICY CONCERNS

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

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

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

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

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[1] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 6616, 6627 (Feb. 8, 2016).

[2] *Id*.

[3] 5 U.S.C. § 706(2)(A).

[4] Motor Vehicle Mfrs. Ass'n v. State Farm Ins., 463 U.S. 29, 43 (1983).

circumstances that … were engendered by [its] prior policy."[5] As explained below, BLM has violated these well-established standards in developing the Proposed Rule. The Proposed Rule is therefore arbitrary and should not be promulgated.[6]

1. BLM may not justify its waste prevention measures by reference to the reductions in methane emissions that they might achieve

One of the primary goals of the Proposed Rule is to reduce the amount of methane emissions from oil and gas operations. In fact, the way the Proposed Rule is promoted, this appears to be <u>the</u> primary goal of the Proposed Rule. The Proposed Rule is cited as one of the principal methane reduction actions under the President's *Climate Action Plan: Strategy to Reduce Methane Emissions*.[7] In addition, BLM has repeatedly emphasized the methane reductions the Proposed Rule would achieve as a justification for its provisions. Most recently, in announcing the extension of the comment period on the Proposed Rule, BLM referred to the Proposed Rule as the "Proposed Rule to Reduce Methane Emissions, Wasted Gas on Public Lands," and as the "Methane and Waste Prevention Rule," and touted the fact that the "proposal is consistent with the Obama Administration's goal to cut methane emissions from the oil and gas sector by 40-45 percent from 2012 levels by 2025." As explained below, BLM lacks authority to require the oil and gas industry to reduce such emissions, except as those reductions may occur as an incident of an otherwise lawful measure to prevent the "waste" of gas adopted pursuant to BLM's authority under the Mineral Leasing Act ("MLA").

BLM is proposing to adopt the waste prevention measures in the Proposed Rule based on the authority granted to it by section 225 of the MLA.[8] That section provides that federal oil and gas lessees, as a condition of their leases, must "use all reasonable precautions to prevent waste

[5] FCC v. Fox TV Stations, Inc., 556 U.S. 502, 516 (2009).
[6] The Proposed Rule is unclear in its applicability with respect to instances of mixed ownership. We seek clarification from BLM on whether operators drilling from a location on state or fee surface ownership that enter or pass through federal minerals will be subject to the Proposed Rule. We contend that these locations should be exempt from compliance with the Proposed Rule. Should BLM apply the Proposed Rule to these locations, it would need to revise its cost-benefit analysis to reflect that decision, as that would add significant costs for operators.
[7] WHITE HOUSE, CLIMATE ACTION PLAN: STRATEGY TO REDUCE METHANE EMISSIONS (2014), https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf
[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.

of oil and gas developed in the land." [9] The Proposed Rule purports to be an attempt to clarify what constitutes a "reasonable precaution" against "waste."

For purposes of the MLA, it is well established that gas is "wasted" only if it could have been economically captured and marketed or put to beneficial use on the lease, but is not. Thus, to establish that a proposed waste prevention measure is a "reasonable precaution" against "waste," and authorized under the MLA, BLM must demonstrate that the gas that is subject to the measure can be economically captured by the operator. If the gas cannot be economically captured, then it is not being "wasted," and BLM has no authority to otherwise regulate what is being done with it, no matter how much methane it may contain.

Even taking BLM's cost-benefit analysis of the Proposed Rule at face value,[10] it is clear that BLM cannot make the required demonstration with respect to several of its proposed waste prevention measures. For example, BLM estimates that its requirement to replace certain pneumatic pumps with zero-emission pumps would impose costs of $2.7 million per year, but would result in only $2.2 million in savings. Thus, the requirement has a negative cost-benefit ratio, or, in other words, BLM cannot demonstrate that the gas that is currently be vented from the pumps subject to the Proposed Rule can be economically captured by replacing the pumps with zero-emission pumps. Even assuming the validity of BLM's analysis, the only way BLM can justify the measure on a cost-benefit basis is by adding in the $18 million in "monetized benefits" that it believes can be achieved in terms of climate change by the reduction in methane emissions that would occur if zero-emission pumps were used.

However, BLM lacks authority under the MLA to justify its waste prevention measures by adding in the supposed climate change benefits that might be realized by society generally from the incidental reduction in methane emissions that would occur if the measures are implemented. Neither the MLA, nor any of the other statutes that BLM cites in the Proposed Rule's preamble, gives BLM the authority to regulate the emission of gas from oil and gas

[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.
[10] The attached economic analysis demonstrates that BLM's cost-benefit analysis is badly flawed and may not be taken at face value.

operations out of a concern about the effect those emissions may have on climate change. That authority, to the extent it exists, has been given by Congress exclusively to EPA under the Clean Air Act. By relying on the benefits of methane reduction to justify its waste prevention measures, BLM is clearly "rel[ying] on factors which Congress [did] not intend it to consider" when developing such measures under the MLA, and is therefore acting arbitrarily and in violation of law.

To demonstrate that a particular measure is a "reasonable precaution" against "waste," BLM must demonstrate that the gas subject to the measure can be economically captured by the operator. Whatever benefits calculated using the social cost of methane might be realized as a result of the measure have no place in that demonstration. The benefits that may flow to society generally are irrelevant to the question of whether the gas can be economically captured by the operator. Put simply, because those benefits do not flow to the operator, they are not benefits that can be spent to capture the gas. Thus, while an otherwise "reasonable" measure to prevent the "waste" of gas may have the incidental effect of reducing the amount of methane that is emitted from oil and gas operations, such a measure may not be made "reasonable" for purposes of the MLA by virtue of that incidental effect.

Federal oil and gas lessees have a right to develop the oil and gas resources on their leases, subject to the requirement that they take "reasonable precautions" to prevent the "waste" of those resources, and that they comply with other applicable federal laws and regulations, like the ones adopted by EPA to regulate air emissions. If they are not "wasting" those resources—i.e., if those resources cannot be economically captured—BLM is not free to impose so-called waste prevention measures on them pursuant to its MLA authority just because society as a whole may benefit from the incidental methane reductions that would occur if the measures were implemented. The oil and natural gas industry has and will continue to work voluntarily to address methane emissions, but federal oil and gas lessees may not be made to bear the costs of reducing those emissions under the guise of BLM's authority to impose "reasonable precautions" to prevent the "waste" of gas.

BLM seems to suggest (without explanation) that its obligation under the Federal Land Policy and Management Act ("FLPMA") to manage public lands under the principle of multiple use, which is defined as "management in a 'harmonious and coordinated' manner 'without permanent impairment to the quality of the environment,'" may provide it with the authority to regulate methane emissions.[11] But that general reference to the "permanent impairment of the environment," which is found only in the definition section of FLPMA, cannot be read as a substantive grant of authority to BLM to set its own methane emission standards, or to limit methane emissions out of a concern for the effect they may have on climate change. There is nothing in the substantive provisions of FLPMA that would support such a reading, or that would give BLM any parameters to observe in exercising such an authority. Especially in light of the detailed and complex provisions for that Congress has established for the regulation of air quality in the Clean Air Act, it is unreasonable to suppose that Congress would give BLM the authority to regulate air quality completely untethered to any substantive guidance from it as to how to exercise that authority. At most, the provision in FLPMA can be read as requiring BLM to insure that activities conducted on federal lands comply with all applicable environmental standards, as established by the agencies with express and substantive authority from Congress to do so.

BLM further confirms the air quality focus of the Proposed Rule when it notes that:

> This waste of gas through flaring can affect the quality of life for nearby residents, who note that flares are noisy and unsightly at night. Venting, flaring, and leaks of gas also contribute to local, regional, and global air pollution. Volatile Organic Compounds (VOCs) and hazardous air pollutants (components of the gas, such as benzene, toluene, ethylbenzene, and xylene) are released into the atmosphere when natural gas is released through venting, flaring, or incomplete combustion at a flare. VOCs combine with sunlight and Nitrogen Oxides (NO_X), which are created by burning fossil fuels, to form ground-level ozone, or smog, which causes a wide range of health effects. Benzene and other components of natural gas are also classified as hazardous air pollutants, which are

[11] 81 Fed. Reg. 6629.

known or suspected to cause cancer or reproductive effects. Flaring of gas produces NO_X and particulate matter, both of which can cause respiratory and heart problems.[12]

However, as explained above, BLM lacks the authority to regulate such emissions for the sake of air quality.

Moreover, even if BLM somehow had authority to require federal oil and gas lessees to reduce methane emissions out of a concern for the effect they might have on climate change, BLM would still have to provide a reasonable justification for doing so, which it has not. Indeed, it is extremely unlikely that the Proposed Rule will have any meaningful impact on global greenhouse gas (GHG) emissions. Global methane emissions are estimated at 6,875 million metric tons CO_2-eq per year, whereas U.S. methane emissions are about 708 million metric tons per year, or about 10.2% of global emissions. BLM estimates that the Proposed Rule will reduce between 4.1 and 4.2 million metric tons of CO_2-eq per year.[13] Taking BLM's 4.2 MMT CO_2-eq per year, the Proposed Rule provides a reduction of 0.061% of global methane emissions. More importantly, methane emissions make up only a small portion of total global GHG emissions. EPA estimates put annual global greenhouse gas emissions at approximately 45,863 million metric tons of CO_2-equivalent (CO_2-eq) in 2010.[14] By BLM's most ambitious estimates, which are likely overstated, its Proposed Rule will reduce greenhouse gas emissions by 4.2 million metric tons of CO_2-eq. That's approximately 0.0092% of global greenhouse gas emissions.

While BLM asserts that "[v]enting and leaks of natural gas in the oil and gas production process also contribute to climate change,"[15] the empirical evidence on this record contradicts BLM's assertion. BLM's proposal is devoid of any discussion or evidence demonstrating how significantly less than a 1% reduction in domestic methane emissions will have any impact on climate change. The APA demands far more than regulation via the precautionary principle. See e.g., Washington Environmental Council v. Bellon, 732 F.3d 1131, 1145 (9th Cir. 2013) (striking

[12] 81 Fed. Reg. 6627
[13] *Fact Sheet on Methane and Waste Reduction Rule.* Bureau of Land Management. January 2016.
[14] U.S. EPA, Climate Change Indicators in the United States, https://www3.epa.gov/climatechange/science/indicators/ghg/global-ghg-emissions.html (last visited Apr. 6, 2016)
[15] *Id.* at 6627.

down Plaintiff's arguments that "any and all contribution of greenhouse gases must be curbed," and noting the common-sense notion that, as articulated in Massachusetts v. EPA, regulatory action should focus on reducing "meaningful contributions" of GHGs).

On a global scale, the purported impact of the Proposed Rule is far from "significant." It is hard to imagine anywhere else where a 0.0092% reduction of anything would be considered significant, particularly given that climate change is a global phenomenon, generally measured on the basis of country-by-country or even continent-by-continent contribution. By justifying the Proposed Rule by reference to climate change benefits and contributions towards mitigating climate change impacts, the Proposed Rule proposal falls far short of the rational basis that the APA requires to support a rulemaking. Simply put, BLM does not make even a slightly credible case that the Proposed Rule will have any impact on climate change.

The Proposed Rule also ignores the reality on the ground in the oil and natural gas production industry. To date, industry has achieved remarkable emission reductions without duplicative and burdensome federal regulations. Methane emissions from oil and natural gas exploration and production (E&P) are 1.07 percent of total U.S. GHG emissions[16] and the natural gas sector alone has reduced methane emissions by 38 percent since 2005. *See EPA, 2014 GHG Reporting Data* (2014). In 2013, "reported methane emissions from petroleum and natural gas systems sector" decreased by 12 percent from 2011, and the largest reduction came from

[16] EPA has announced modification of the petroleum and natural gas systems methane emissions estimates in the GHG Inventory. EPA asserts that this change reflects new data. Two changes affecting the exploration and production component are at issue. The first involves estimating emissions from gathering and boosting activities that have not been reported under the GHG Inventory which EPA is arbitrarily assigning to production. The second involves methane reported under Subpart W suggesting that some exploration and production emissions are higher than previous estimates. Much of EPA's rationale for increasing the GHG Inventory for these emissions hinges on scaling up the Subpart W reported emissions to reflect the entire industry. EPA indicates that only 30 percent of exploration and production facilities report under Subpart W. However, EPA's efforts to scale up emissions appear to rely too heavily on the facility number rather than its nature. Clearly, the non-reporting facilities would overwhelmingly be marginal oil and natural gas wells. Marginal wells would have a very different and lower emissions profile than the larger facilities reporting under Subpart W. Even EPA initially recognized this distinction when it selected the facility size for reporting under Subpart W. It chose the threshold that yields the 30 percent of facilities reporting because EPA concluded that these facilities accounted for 85 percent of emissions. Consequently, EPA's actions to alter the GHG Inventory need to be thoroughly vetted before they are accepted. If they are found to be accurate, these changes increase the "production" segment of the petroleum and natural gas systems share of GHG emissions to 2.45 percent of the total GHG Inventory or 1.83 percent if the historical definition of exploration and production were used. However, these changes would not be an actual increase in emissions but an alteration of the entire baseline for the Inventory.

hydraulically fractured natural gas wells (resulting in a decrease of 73 percent in emissions). *Id.* According to a study by the University of Texas, Austin, methane emitted from all upstream source categories at natural gas production sites represents just 0.42 percent of gross natural gas production volumes.[17] On a national scale, despite significant growth in production in this sector over the past several years, methane and other emissions have continued to decline.

Technological and operational improvements in this sector continue to advance at remarkable rates and the emissions profile for new and modified facilities is declining and will only continue to do so, particularly as operators move towards centralized gathering systems and tankless or pressurized tank facilities. For example, in Colorado, recent emissions inventories for the oil and gas sector demonstrate significant *decreases* (*i.e.*, more than 60 percent through 2017) in VOCs despite a growth in production. *See Overview of 2011 and 2017 VOC and NOx Emission Inventories*, Colorado Regional Air Quality Council, at 7 (November 19, 2015). These decreases are due to advances in technology, facility design, better emissions controls, and the inherent incentive to capture and sell as much methane as possible. New facilities in combination with growing infrastructure and voluntary and state-led emission control efforts are already resulting in decreases in sector emissions. Unlike virtually every other industrial sector, production in upstream E&P sources declines over time bringing with it declining emissions (of both VOCs and methane). The Proposed Rule ignores these fundamental realities. Until these contradictions can be satisfactorily explained, any decision to regulate in the face of such overwhelming data would be arbitrary.

In fact, by making natural gas development more expensive and time consuming, the result will be less American natural gas production than without the Proposed Rule, which is directly at odds with the President's overall climate goals. Specifically, since increased natural gas electricity generation is the primary reason that the United States has reduced GHG emissions, as recognized by the International Energy Agency, the Energy Information Administration, and EPA's data, the Proposed Rule is actually counterproductive to efforts to

[17] David T. Allen et al., *Measurements of Methane Emissions at Natural Gas Production Sites in the United* States, 110 Proc. of the Nat'l Acad. of Sci. of the U.S. 18023 (2013).

address climate change.[18] By focusing on the small picture, BLM is losing sight of the bigger picture.

2. BLM's prohibitions on venting and flaring by operators with NTL-4A approvals are arbitrary

Another primary goal of the Proposed Rule is to reduce the amount of associated gas that is being routinely vented or flared from development oil wells. Under current BLM policy, which is set forth in NTL-4A, such venting and flaring is generally prohibited and may only take place with BLM's written approval. To obtain that approval, an "operator [must] demonstrate to the satisfaction of" BLM, based on "an evaluation report supported by engineering, geologic, and economic data, "that the expenditures necessary to market or beneficially use such gas are not economically justified and that conservation of the gas, if required, would lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered if the venting or flaring were permitted to continue." Hundreds of operators have made the demonstration required by NTL-4A to BLM's satisfaction and are currently venting or flaring with BLM's written approval.

BLM is now proposing, however, to do two things in section 3179.6 of the Proposed Rule that are in direct conflict with those approvals. First, it is proposing to prohibit all routine venting of gas, subject to certain narrow exceptions. In other words, it is proposing to find, as a matter of law, that routine venting, regardless of the circumstances of the operator and any approval that has been given to it by BLM under NTL-4A, is a "waste" of gas. Second, it is proposing to limit all routine flaring of gas, subject to certain narrow exceptions, to 1,800 Mcf/month per well. In other words, it is proposing to find, as a matter of law, that "very high rates of flaring from a lease—that is, rates above the proposed 1,800 Mcf/month limit—constitute unreasonable waste under the MLA," regardless of the circumstances of the operator and any approval that has been given to it by BLM under NTL-4A.[19] BLM is proposing to say, in effect, to all operators who currently have BLM's express approval to vent under NTL-4A

[18] U.S. Int'l Energy Agency, World Energy Outlook, (2011) http://www.iea.org/Textbase/npsum/weo2011sum.pdf.; See Figure 12 at U.S. Energy Information Admin., U.S. Energy-Related Carbon Dioxide Emissions, http://www.eia.gov/environment/emissions/carbon/ (last visited Apr. 6, 2016).

[19] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. at 6639.

(based on BLM's case-by-case examination of their particular circumstances) that they may no longer vent, and to all operators who have BLM's approval under NTL-4A to flare amounts of gas in excess of 1,800 Mcf/month per well (based on BLM's examination of their particular circumstances) that they may no longer do so. And BLM is proposing these new prohibitions, which may lead to the shutting-in of wells, without any explanation as to why the venting and flaring it approved should now be prohibited.

In making its proposal to replace NTL-4A with the Proposed Rule, BLM is "disregarding [the] facts and circumstances that … were engendered by [its] prior policy"—i.e., the well-specific determinations that it made under NTL-4A that current levels of routine venting and flaring of associated gas from particular oil wells is not a "waste" of gas—and is proposing to simply declare by fiat that what it once considered not "wasteful" it now considers "wasteful." By failing to explain on a case-by-case basis why its existing approvals should be revoked, BLM has "entirely failed to consider an important aspect of the problem" that it claims it is trying to address. Thus, the proposed prohibitions on venting and flaring in section 3179.6 are arbitrary as applied to operators who are currently venting and flaring with BLM's approval. Unless and until BLM can explain, on a case-by-case basis, why its previous approvals, on which operators have reasonably relied, are in error, it may not simply set those determinations aside and impose new prohibitions on the operators. Consistent with its obligation not to act arbitrarily, BLM cannot say one day to an operator that a particular practice, as a matter of fact, is not "waste," and then say to that same operator the next day that that same practice, as a matter of law, is "waste."

The Proposed Rule does give operators subject to the flaring prohibition (but not those subject to the venting prohibition) the option of applying for an alternative flaring limit. But operators should not be put to the time and expense of demonstrating to BLM under the Proposed Rule what they have already demonstrated to BLM under NTL-4A—i.e., that the flaring they are doing is not a "waste" of gas. The demonstrations required by NTL-4A having been made to BLM's satisfaction, BLM now bears the burden of explaining with supporting facts why the NTL-4A approvals that were based on those demonstrations should be set aside. Unless BLM provides such an explanation based on the particular circumstances of each operator, operators with approval to vent and flare under NTL-4A must be exempted from the Proposed Rule's venting and flaring prohibitions. If BLM were to retroactively reverse course on currently approved venting and flaring, many well would need to be plugged and abandoned, resulting in the loss of otherwise economically recoverable oil and natural gas reserves.

3. The 1,800 Mcf/month flaring limit is arbitrary

As explained above, BLM's MLA authority is limited to requiring that operators take "reasonable precautions" to prevent "waste" of gas. The Proposed Rule is based on the notion that a "reasonable precaution" would be to limit the amount of gas that can be flared from each well to 1,800 Mcf/month. For three reasons, however, the proposed limit is arbitrary and should not be promulgated.

First, as explained above, the limit is arbitrary as applied to operators who are currently flaring with BLM's approval. Unless and until BLM can justify, on case-by case basis, the setting aside of those approvals, any imposition of a new limit is arbitrary.

Second, the limit is arbitrary as applied to leases issued after the effective date of the Proposed Rule because it makes no allowance whatsoever for the widely varying circumstances of the leases and the wells drilled on them. Under the Proposed Rule, if a well is drilled on a lease that is issued after the effective date of the Proposed Rule, it is subject to the flaring limit, regardless of the circumstances. NTL-4A, on the other hand, has wisely recognized for over 30 years the undeniable fact that there are a variety of factors that must be taken into account in determining whether gas from a particular well can be economically captured. It therefore provides all operators, regardless of when their lease was issued, the opportunity to seek an exception from NTL-4A's general prohibition against venting and flaring on a well-by-well basis. In the preamble to the Proposed Rule, BLM justifies its change of course on the backlog of sundry notices awaiting approval. While we are concerned with this backlog of sundry notices, we would argue that BLM's resources could be better put to use by addressing that backlog, rather than embarking on a time-consuming new regulatory process.

Third, the 1,800 Mcf/month limit is itself arbitrary, regardless of how it is applied to different classes of operators. "To select an appropriate numeric limit for flaring," BLM simply "analyzed data indicating the average flaring rates across wells."[20] Based on that analysis, it then calculated the number of the oil wells that would be impacted by limits of 1,200, 1,800, 2,400 and 3000 Mcf/month. For example, it calculated that a limit of 1,800 Mcf/month would "impact about 16 percent of the oil wells flaring associated gas." It then chose the 1,800 Mcf/month limit, not because of its effect on preventing "waste" of gas, but because, it "would effectively maximize flaring reductions while minimizing the number of affected leases."[21]

Fourth, BLM's own economic analysis recognizes that, at best, the proposed flaring limit benefits are highly uncertain. At worst, those benefits could be negative by as much as $10 million, indicating a net cost to society[22].

What is entirely missing from BLM's analysis is any attempt at all to calculate how much "waste" each of the flaring limits it considered would prevent. Reductions in flaring, which is the only metric BLM used, do not equate to prevention of "waste." There is no linear relationship between the two concepts, as witnessed by the amount of flaring that is taking place pursuant to NTL-4A approvals, and is therefore not a "waste" of gas. Unless and until BLM can demonstrate the effect that the 1,800 Mcf/month limit will have on reducing "waste," it is an entirely arbitrary limit that may, in fact, require significant reductions in flaring that is not "waste." On the current record, it is obvious that BLM, in proposing the 1,800 Mcf/month flaring limit, is interested only in reducing flaring solely for the sake of reducing flaring, and its associated methane emissions, rather than reducing flaring for sake of preventing "waste" of gas.. As explained above, however, BLM does not have authority under the MLA to require operators to take "reasonable precautions" to prevent flaring; it only has authority to require operators to take "reasonable precautions" to prevent "waste." Due to BLM's lack of analysis, it

[20] *Id.*

[21] *Id.* at 6640. This, of course, is not true. A 1,200 Mcf/month limit would "maximize" flaring reductions, while a 3000 Mcf/month limit would "minimize" the number of affected leases.

[22] *Id.* at 6620

is impossible to discern whether the 1,800 Mcf/month limit is a "reasonable precaution" against "waste."

The 1,800 Mcf/month number was derived from the Utah and Wyoming state rules, referenced below, that are totally unfit as models for a nationwide standard. Utah's flaring limit of 1,800 Mcf/month is set forth in 1988 in Section 1.1 of Utah's Administrative Code, R649-3-20 *Gas Flaring or Venting*. Utah's decision to adopt the limit was based on the unique operational and geologic conditions in the Altamont Bluebell field in Utah's Uinta Basin during the 1970s and 1980s. The Altamont Bluebell field is a vertical play; even today, little horizontal drilling exists as compared to other large unconventional plays. Geologically, the reservoir is primarily tight sandstone with extensive natural fractures. The main hydrocarbons are a high paraffin crude oil, known as "waxy crude" that is substantially different in its chemical composition from the light shale oils being developed in today's unconventional plays in the Bakken and Permian basins.

BLM's proposed flaring limit a one-size-fits-all solution rather that fails to recognize that different regions have different challenges. The proposed limit on flaring is so far from reality in certain basins that it would make future development of federal oil wells nearly impossible. The proposed limit is based on a limit that was developed for conventional plays in Utah and Wyoming with adequate infrastructure that have been primarily developed with vertical wells. However, today's unconventional plays allow one well to replace four or even eight conventional vertical wells. Overall, this trend offers tremendous environmental benefit by greatly reducing the surface impact of development. Notably, though, these new horizontal wells are replacing many vertical wells and have commensurately higher production. These unconventional plays are relatively new, which means that the full development cycle of a field is not yet fully understood. Some operators have found that GOR actually increases as unconventional wells decline. This could have potentially complicating implications for long-term development, particularly under extremely tight flaring limits.

According to one New Mexico operator, BLM's proposed 1,800 Mcf/month flaring limit would cause them to reduce the amount of production so significantly that they would only produce 17 barrels of oil a day (BOD). Currently, the average GOR of this particular operator's wells in New Mexico is 3,500 scf producing an average of 68 BOD. Limiting flaring to 60 Mcf per day, given their GOR, would, in turn, cause them to limit oil production to 17.1 BOD. Requiring operators to limit production to 17 BOD significantly impacts their ability to cost-effectively operate these wells. Operators have predetermined fixed costs that cannot be paid if they have to curtail their production. This will further impact their ability to drill additional wells as their cash flow declines. Not only will operators' cash flow plummet, but so will the federal and state governments' stream of income which depends on royalties—again directly contrary to the stated purpose of the proposed regulations. This also greatly impacts private mineral owners with royalty in federal CAs or units. To meet these thresholds in the Bakken, additional equipment must be installed to shut-down wells based on a flare meter. Pigging will also be problematic, as it requires maintaining flow even as pressures go up and will result in increased flaring. A solution involving well shutdowns will lead to cycling across the whole field as various operators turn production streams off/on. Equipment failures will increase in areas constrained to make sales.

Bakken wells produce more than twice the oil and about 1.5 times more gas in the first month of production than an Altamont Bluebell development well. After the first year of production, the typical Bakken well produces 140 barrels of oil per day (bopd)/150 Mcf per day (Mcfpd). By comparison, production after the first year from Altamont Bluebell wells averages 53 bopd/120 Mcfpd. There is also a vastly different scale of development between the two fields. Since 2000, only 462 wells have been developed in the Green River or Wasatch formations in the Altamont Bluebell field. In the Bakken, 10,629 wells have been developed in the Bakken or Three Forks formations during that same time.

In certain areas of the Bakken, an operator may exceed the proposed 1,800 Mcf/month limit in a period of hours, as GOR can be up to 4 Mcf/bbl. What is lost in BLM's monthly limit is proportionality to the well. A horizontal well equates to several vertical wells, in the range of eight to twenty, depending on the number of frack stages and the length of the lateral. Applying the same flaring limit to a low volume vertical well as to a horizontal well equivalent to multiple vertical wells is simply not logical.

In the Permian Basin, the problem is also severe. One member reports its production from federal wells averages 68 bopd/238 Mcfpd. The Southwest New Mexico portion of the Permian Basin contains over 4 million acres of federal minerals with 2,350 well developed since 2010. As a result, increasing gas capture in the Permian is an entirely different undertaking compared to the relatively modest volumes produced in Utah's Altamont Bluebell filed.

Even after applying the flexible monthly averaging proposed by BLM, there is no way around the basic reality that BLM is two orders of magnitude apart from the on-the-ground reality in unconventional plays. That means that per-well gas production in some unconventional plays may 100 times greater than BLM's proposed flaring limit. The economic impacts on Permian and Bakken wells will be significant on both existing leases and future development. Even after applying the flexible monthly average limit, these volumes are too low for Permian and Bakken operations and will significantly impact well economics on existing leases and future development if/when the infrastructure catches up.

4. BLM fails to consider the most important factors affecting the availability of pipeline infrastructure

BLM states that "the primary alternative to flaring associated gas from oil wells is to capture [it], transport [it] in pipelines, and process [it] for sale."[23] BLM states further that the primary reason that more gas is not being captured and transported in pipelines is that "[i] n some areas, there is capture infrastructure, but the rate of new well construction is outpacing infrastructure capacity," while in other areas, "capture and processing infrastructure has not yet been built out."[24] Thus, in order to justify imposing a flaring limit on operators – which is based on the assumption that operators could capture more gas than they currently are – BLM must demonstrate that its Proposed Rule will solve the problem of pipeline availability. Without solving that problem, operators will have little chance of meeting the flaring limit and its imposition on them will be arbitrary.

[23] *Id.* at 6619.
[24] *Id.*

In BLM's view, the primary reason that capture infrastructure is not available is that "in a new field, operators and the midstream processing companies that commonly build and operate gas gathering and processing infrastructure may not have sufficient information about how much gas will be produced to invest in building gathering lines and processing plants."[25] It therefore proposes to solve this problem by requiring in section 3162.3-1(j)(4)(v) that operators develop and submit a "waste minimization plan" with each Application for Permit to Drill (APD) that includes a "[c]ertification that the operator has provided one or more midstream processing companies with information about the operator's production plan, including the anticipate completion dates and gas production rates of the proposed well or wells."

In designing its solution to the problem of pipeline availability, however, BLM "entirely failed to consider [two] important aspect[s] of the problem," and its solution is therefore arbitrary and destined to fail.[26] First, BLM assumes that gas capture infrastructure will be developed in advance of proven oil production and increased field development if operators would only share information about their project production rates with midstream processing companies at the time it submits an APD to BLM. However, in reality, operators must first prove production for a new oil play and initiate larger scale development before the midstream processing companies are willing to invest capital in new facilities or in the expansion of existing facilities. Just sharing "projected gas production rates" with midstream processing companies is not enough.

Second, BLM completely overlooks the most significant reason why new production outpaces infrastructure capacity—i.e., the time-consuming process of obtaining the necessary pipeline rights-of-way from BLM. The process of obtaining the necessary rights-of-way can sometimes take years. In these situations, operators are left with no choice but to flare associated gas from production or shut in their wells.

The following provides illustrative details of the time needed to obtain approval to construct a pipeline across federal land, including tribal land, in this case, the Fort Berthold

[25] *Id.*
[26] Motor Vehicle Mfrs. Ass'n v. State Farm Ins., 463 U.S. 29, 43 (1983).

Indian Reservation. It does not even take into account the time needed to obtain the necessary approvals to cross state and private land:

1. Obtain permission to survey (PTS) from landowners and submit to BIA (Bureau of Indian Affairs) New Town office for approval. ***(4 weeks)***

2. "Soft stake" the pipeline centerline after PTS has been granted by BIA (surveying company/ engineers). ***(1 week)***

3. Schedule Environmental Assessment (EA) onsite with representative from the BIA-New Town office. ***(1 week)***

4. Prepare final plans. ***(3 weeks)***

5. Prepare and send scoping letter for approved pipeline (if applicable, for trunk lines only, lateral lines to well locations will not require scoping). ***(4 weeks)***

6. The EA cannot be submitted until the end of the 30-day comment period

7. Schedule Right-of-Way (ROW) onsite with the BIA-New Town office. ***(1 week)***

8. Prepare EA and cultural reports; from initial surveys conducted in step 3. ***(12 weeks)***

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

10. Submittal of EA to BIA Aberdeen office and Finding of No Significant Impact (FONSI) is reached. ***(4 weeks)*** There is a 30-day notice period after the FONSI is issued

11. Pipeline Company obtains landowner signatures agreeing to terms and payment. These signatures are then filed in the ROW application that is submitted to the BIA New Town office for approval. ***(4 weeks)***

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

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

If BLM is serious about reducing flaring that occurs, by its own analysis, because "the rate of new well construction is outpacing infrastructure capacity," then it must it must design a rule that facilitates the timely and predictable processing and approval of pipeline right-of-way applications.

5. BLM fails to establish a rational connection between "the factors driving flaring" and the choices it made in the Proposed Rule

BLM "recognizes that … operators do not want to waste gas," as it is "a valuable commodity that operators can sell at a profit."[27] Yet the need for the Proposed Rule is based on the premise that notwithstanding that powerful economic incentive, operators are "wasting" a substantial amount of gas through venting and flaring and must therefore be prevented from doing so. Accordingly, to justify its Proposed Rule, BLM must explain why the operators are acting against their own economic self-interest, and why and how its Proposed Rule is necessary and effective to change that behavior.

In addition to the lack of capture infrastructure, which is discussed above, BLM gives four other explanations for why operators are allegedly "wasting" so much gas in spite of the economic incentive they have to capture it. First, BLM asserts that because the "the economic

[27] *Id.* at 6638.

return on oil production is substantially higher than the economic return on gas production … there is an economic incentive for individual operators to focus on oil development at the expense of gas-capture."[28] But operators' focus on oil development is an entirely rational one, and it is one that presumably benefits the federal government in the form of higher royalties, which is one of the principal goals BLM claims it is seeking to achieve through adoption of the Proposed Rule. This explanation therefore does not provide a rational basis for the Proposed Rule's requirement that operators capture more gas where "the economic return of oil production is substantially higher than the economic return on gas production," as doing so will work to the economic detriment of both the operator, the federal government, the public and Indian tribes.

Second, BLM asserts that some operators simply lack "awareness of the available cost savings" from capturing more gas, and thus "fail to capture the economic benefits of investing in waste reduction measures."[29] But BLM offers no support for its inherently implausible assertion that operators are ignoring significant cost saving opportunities. Accordingly, it is reasonable to conclude that there must be some other reason that would explain their behavior. Indeed, as discussed above, BLM completely overlooks one of the primary reasons why are operators are not capturing more gas, which is that, in spite of the best intentions of operators and pipeline companies, the build out of the pipeline infrastructure that is needed for gas capture is heavily dependent on the pipeline companies receiving in a timely fashion the necessary rights-of-way from BLM, state, tribal and private landowners. Those approval processes can take an inordinate amount of time. Moreover, even if BLM were correct in its assertion about lack of operator awareness, it does not take a complex command and control regulation of the type that BLM is proposing to solve the problem. BLM could simply provide the operators the information of which it claims they are unaware, and then let the strong economic incentive that they already have motivate them to capture the gas.

Third, BLM notes that some companies fail to invest in gas-capture technologies because of "limited capital availability."[30] Where this is the case, the problem will not be solved by the Proposed Rule. Instead, by placing an arbitrary and across-the-board limit on the amount of gas

[28] *Id.*
[29] *Id.*
[30] *Id.*

that can be flared, the Proposed Rule may cause operators to forego development of certain oil reserves entirely. In the example referenced above, a Permian operator reporting a field average of 68 bopd/238 Mcfpd would be forced to choke back its oil production from 68 bopd to 17 bopd in order to meet BLM standards. That translates into a 75% decline in production, and consequently in revenue and royalties. Besides limiting the economic viability of oil development in that particular basin, it represents a waste of resources, which should be considered antithetical to a rule proposing to minimize "waste."

Fourth, BLM underestimates the fact that even when gathering infrastructure is in place, some flaring and venting may be unavoidable due to gas quality, plant processing capacity, maintenance and other factors. Under NTL-4A, flaring due to equipment failures, relief of abnormal system pressures, or other conditions resulting in short-term venting or flaring is authorized without incurring royalty obligations. These situations often occur over a short period of time and may come with little to no notice. Generally, they are outside of operators' control and even close coordination between upstream and midstream companies will not eliminate them entirely. To assume otherwise would be unreasonable.

Finally, BLM asserts that "operators typically consider only the costs and revenues of gas capture with respect to their individual operation," and that "in many instances, when costs and revenues are evaluated across a larger area, … gas capture … may be more economical."[31] However, operators can only "consider … the costs and revenues of gas capture …across a larger area" when they control the assets in that larger area, which is often not the case. They do not know, and cannot consider, the "costs and revenues of gas capture" of their competitors.

As BLM fails to establish a rational connection between the factors it believes are driving flaring and its proposed solution of requiring operators to provide more information to "midstream processing companies" at an earlier date, and complying with one-size-fits-all venting and flaring limits, the solution is arbitrary.

[31] *Id.*

6. BLM has not demonstrated that it will have the resources necessary to administer the Proposed Rule in a timely fashion

The Proposed Rule would place significant new responsibilities on BLM, as set forth in sections 3162.3-1, 3197.7, 4179.10, 3179.11, 3179.201, 3179.202, and 3179.401. BLM's ability to perform those responsibilities in a timely manner is key to the successful working of the Proposed Rule. Yet the preamble contains no estimates of the additional resources that BLM will need to administer the Proposed Rule, nor any assurance that those resources will be available to it, nor does it set any deadlines for BLM's fulfillment of its responsibilities so that operators can reliably plan their operations.

BLM is already failing to timely fulfill its current oil and natural gas program responsibilities, particularly with respect to the approval of APDs and pipeline rights-of-way across federal lands. This latter failure is particularly significant in light of the Proposed Rule's effort to stimulate the timely building of more pipeline infrastructure so that more gas can be captured. Thus, before any final rule is promulgated, it is imperative that BLM assess and disclose to the regulated community whether it will be able to effectively administer the rule with the resources available to it. Just as BLM was required to quantify the time burden and costs that the information collection requirements of the Proposed Rule will impose on the public, so should it be required to quantify the time burdens and costs that the Proposed Rule will impose on itself, and to demonstrate that it will be able to fulfill its new administrative responsibilities in a timely fashion. BLM should not impose significant new requirements on the oil and gas industry without demonstrating that it will not become a bottleneck in the industry's efforts to comply with those requirements.

7. BLM's Regulatory Impact Analysis is deeply flawed and does not support adoption of the Proposed Rule

We have attached a thorough analysis of the Regulatory Impact Analysis ("RIA") on which the Proposed Rule is based. The analysis demonstrates that the Proposed Rule will impose costs of $1.26 billion annually to the economy, and that those costs far outweigh even the highest end BLM benefit estimate of $384 million.[32] This is based on a price for natural gas of $2.00/Mcf.[33]

This year, natural gas prices have dropped to as low as $1.57 per million BTU and $1.40 Mcf according to the EIA and media sources. Discounting the idea that a reduction in potential methane emissions would have any benefit on the environment that could be monetized, a more reasonable calculation of the potential benefit of the Proposed Rule would be $90 million. With a cost of $1.26 billion and a potential benefit of just $90 million, the Proposed Rule does not produce a net social or economic benefit. Additionally, those economic losses create an additional loss of $114,112,000 in federal and state taxes.

The benefits as laid out by BLM are also speculative at best as they rely on passage of EPA Subpart OOOOa and on certain flawed assumptions that methane gas reductions have a social cost benefit.

In addition to not completing the RIA in accordance with published OMB guidelines, BLM included a number of assumptions that were on their face either false, or should not have been used as part of this type of analysis. The most glaring problem, however, is BLM's inflated commodity price estimates which underlie the economic benefit estimate in an economy where commodity prices, significantly for oil and natural gas, are in their biggest bear market in 30 years. Additionally, the central purpose of any regulation is to have an in-depth safety focus, which is not examined in any real depth in this RIA, especially when limits for venting or flaring per well are suggested as a remedy in a very broad context.

BLM's failure to conduct a comprehensive alternative analysis was clearly in violation of the OMB guidelines. An alternatives analysis may have shown that the proposals could actually lead to increased and significant economic costs to the oil and gas industry.

In addition to the flaws in the RIA, the Associations are concerned by the numerous instances where BLM ignores significant economic burdens that would result from its Proposed

32 Op. cit. Regulatory Impact Analysis, pages 6-8.
33 Op. cit. Regulatory Impact Analysis, page 42.

Rule. This is particularly evident in the proposed flaring limits, but runs throughout the Proposed Rule. BLM generally underestimates or ignores entirely the development costs in terms of both time and capital with building out pipeline infrastructure. The proposed flaring standards, when applied broadly, will severely limit producers' ability to develop oil wells and will discourage investment in new plays. BLM's economic analysis understates the complexity of the economics of developing pipelines.

In the immediate term, the effects of the Proposed Rule will be pronounced, but in the longer term it means that the domestic energy renaissance we have recently witnessed would be extremely difficult to sustain. The overwhelming capital costs of developing new fields and expanding current fields into new areas would strongly deter investment and would have lasting economic, geopolitical and environmental consequences in this country. In addition to the potentially severe economic consequences the proposed rule would create, BLM failed to fully contemplate the environmental impacts of its proposal. Since oil and natural gas can be produced in many different countries the regulations may simply transfer activity from the United States to Russia, Mexico, Iraq or Nigeria. This can not only impact the American economy but could also lead to increased methane production.

8. BLM overstates the effectiveness of remote gas capture technology

In the preamble of the Proposed Rule, BLM describes several alternative gas capture technologies that it believes can be used as an alternative to flaring. However, in support of this, BLM relies heavily on the Carbon Limits study that bases its assumptions on gas prices that are more than double today's market value of natural gas. BLM goes on to suggest that due to these remote capture technologies, "[w]hile flaring in these situations has generally been considered unavoidable, the BLM believes this assumption is challenged by the development of the alternative capture technologies described above, which calls into question whether it remains reasonable to assume that there are no alternatives to flaring when a field produces only a small quantity of natural gas."[34]

[34] *Id.* at 6637.

This selective review of remote capture technology fails to acknowledge the overwhelming evidence from on-the-ground experience with these control strategies. Numerous operators have deployed remote gas capture technology in the field, and their experience has clearly demonstrated that in the vast majority of cases, this technology is not economically viable.

Additionally, the expanded use of remote natural gas capture technology would necessitate expanding the footprint of many wellpads to safely accommodate the additional equipment. The emissions, noise, and dust associated with the additional construction requirements would have environmental consequences that BLM has failed to fully consider. The installation, operation, and maintenance of these remote capture facilities would also require additional truck traffic, resulting in additional vehicle emissions.

According to one North Dakota operator, "based on its extensive evaluations of remote capture technology, [we have] concluded that the technologies are not economically viable given their substantial cost in comparison to the nominal value of gas being flared.... To the extent that they are economically viable at all, remote capture technologies have the greatest likelihood of providing an economically viable alternative to flaring when the technologies are deployed to capture gas flared from stranded wells (i.e., wells incapable of being connected to a pipeline). Unlike wells connected to pipelines, which intermittently and unavoidably flare negligible volumes of gas, stranded wells flare larger volumes of gas..."

Another operator found, "[o]ur efforts to date establish that remote capture technology is uneconomic and will not alleviate flaring or resolve pipeline capacity and constraint issues."

A third operator noted, "[t]he remote capture technologies presently available are uneconomical and they do not entirely resolve gas flaring. The lease cost of the remote capture units (NGLs) are greater than the value of the natural gas liquids they produce at current market prices…. NGL units are notoriously difficult to winterize and have low winter runtimes. NGL units require semi-stable inlet gas rates to run; many connected sites flare intermittently which would make operation difficult and runtimes low. NGL units require a large footprint to safely operate, which is an issue on smaller pads. [Current] vendors are not able to scale down further than 250 [Mcfd], which is greater than the amount of flaring on most connected sites. Additionally... the NGL unit will reduce but not eliminate the flare."

One operator developed an economic model that represents a theoretical application of remote capture technology in which 12 months of gas capture is required to satisfy regulatory requirements for a new location. This model is based on average costs incurred over 15 locations during 2014, and pricing believed to be available in October 2015. A unit with 2,000 Mcfd capacity was selected to match with production forecast in month 4 of production. Prior to month 3, some gas will be flared. After month 3, the equipment will be underutilized. A location gas capture goal of 85% is assumed.

The following assumptions were made:

<u>Gas Capture Unit Capacity:</u> 2,000 Mcfd

<u>Direct Service Costs Including:</u>

Mobilization and installation charges

Costs of moving equipment to location, cranes, pipe, valves, and fittings, roustabout work, electrical installation, hydrostatic testing, and commissioning. Assumed equipment is moving from gulf coast.

Monthly fees to service company

Includes lease, operation, and maintenance of compressors (2), mechanical refrigeration unit (2), stabilizer (2), natural gas generators (2), product storage tanks (2), and waste tank (1).

Project term: 12 months

Demobilization fee at term end

Includes breakdown and removal of piping, electrical, crane, and trucks to lift and remove equipment skids from location

Total payments to gas capture operator: $750,000

Company Costs: $124,430

Site preparation

Company oversite billed to location

Company gas capture supervisor on location 8 hours per week during operation, plus one company consultant on location 8 hours per week during operation. Excludes cost associate with field safety and environmental personnel, and administrative costs.

Tie-ins to gas plan

Includes custody transfer gas supply meter to gas plant and meter for residue gas stream to flare, and piping required to connect treaters to gas plant

Total Costs for Four-Month Operation: $874,430

Production Data

Equipment availability assumed: 90%

Total gas processed: 492,750 Mscf

Assumed that 75% utilization of available capacity is used due to production decline below equipment capacity maximums

Average gallons extracted per Mscf processed: 2

Total NGLs extracted and sold: 985,500 gallons

2015 Economics of Project

Average revenue per gallon after	$0.22

transportation, fractionation, and marketing	
Total project revenue	$216,810
Total project costs	$874,430
Net project profit/(loss)	($657,620)

This economic analysis underscores how critical it is for BLM to recognize current commodity prices in its analysis. Using an outdated study based on inaccurate price data tells a vastly different story than an analysis based on current economics. As the above analysis based on real-world market conditions demonstrates, BLM's belief that these types of remote capture technologies are economical cannot be supported.

III. SECTION-SPECIFIC CONCERNS

Many of the provisions that we discuss below have been addressed by EPA in its proposed rule for new and modified sources of emissions or will be addressed by EPA in the rule that it is now developing to address existing sources of air emissions from oil and gas operations. These include venting and flaring limits, Leak Detection and Repairs (LDAR), replacing high-bleed pneumatic controllers and pneumatic pumps, and limiting emissions from downhole well maintenance and liquids unloading. Consistent with BLM's policy, which is to avoid mandates that would be duplicative of, or conflicting with, those imposed by EPA, BLM should defer to EPA on this issue and not proceed with its proposal. If BLM chooses to promulgate the provisions in spite of their arbitrary nature and BLM's lack of authority to do so, then it must address the following concerns that we describe below.

A. Actions to reduce the "waste" of gas

1. Prohibiting venting of associated gas

Section 3179.6(a) "would require operators to flare all gas that is not captured, except under certain limited circumstances."[35] The Proposed Rule states that the "operator must flare rather than vent any gas that is not captured."[36]

As explained above, this prohibition should not apply to operators with current NTL-4A approvals. However, regardless of to whom it applies, it is not a "reasonable precaution" against the "waste" of gas, and should not be promulgated. As explained below, a total cessation of venting is not feasible in many instances for safety and economic reasons. Moreover, it is grounded in a concern for the reduction of methane emissions, rather than in a concern for the prevention of the "waste" of gas, as is required by the MLA. If BLM chooses to promulgate the prohibition, in spite of its arbitrary nature and lack of authority to do so, then it must address the following concerns.

1. The Proposed Rule's stipulation of a "no venting" standard is highly problematic and fails to acknowledge the operational realities of the oil and natural gas industry. Operators minimize the venting of gas whenever possible for economic and safety considerations. Venting is generally avoided when it is feasible and practical to do so.

However, there are situations when a "no venting" standard is impossible to meet. There are numerous instances where a *de minimis* volume of gas will be vented and any attempt to capture that gas would be technically and economically infeasible. For instance, during drilling operations, there are very small volumes of gas entrained in drilling mud. When mud is processed, small pieces of drilling cuttings are filtered out using devices like mud shakers. During the process of removing these cuttings, some of the gas entrained in the drilling mud will be released into the atmosphere. These volumes are exceedingly low and have virtually zero economic value, and it would be impossible to completely eliminate these emissions in meeting a

[35] *Id.* at 6666.
[36] *Id.* at 6682.

“no venting” standard. Other instances in which such a standard is infeasible would be when small amounts of gas have to be vented to blow and depressurize equipment to work on it. We ask BLM to clarify that these instances would be clarified in its clause on technical infeasibility.

Other situations may involve low API gravity oil production from certain wells. In instances where the gas-to-oil ratio (GOR) is low or an oil is particularly heavy there may be very low volumes of associated gas that cannot be feasibly separated out at the wellhead. In these instances it is unrealistic and unreasonable for BLM to expect operators to totally eliminate venting.

Permian Basin production offers another example of the infeasibility of a “no venting” standard. A significant amount of associated gas is produced with horizontal drilling in the Permian Basin. Many wells do not have gas in the formation downhole, but rather it is actually dissolved in the oil and water and is only present as the pressure is reduced on the liquids. This pressure drop occurs when the oil and water are sent from the flowback separator at 50-200 psi to the tanks which are at atmospheric pressure. There will always be some gas that comes out of solution during this process and is vented through the tanks.

If BLM adopts a venting prohibition, then it must clearly allow an exception for the venting *de minimis* volumes like the examples describe above; requiring operators to eliminate venting entirely is impossible given today’s technological and economic constraints.

2. It is clear from the preamble that the prohibition is intended to apply only to venting from development oil wells, but the Proposed Rule does not so state. Accordingly, section 3179.6(a) should be revised to state that “the operator of a development oil well must flare rather than vent any gas that is not captured.”

3. While section 3179(a) of the Proposed Rule states that the “operator must flare rather than vent gas that is not captured,” section 3179.6(b) states that an operator “must not flare <u>or</u> vent gas” (emphasis supplied) in excess of the limits that the Proposed Rule establishes, thus appearing to allow an operator to continue to vent gas as long as the total volume of gas that is

flared or vented is not in excess of the limits. If this is what BLM intended, it would be preferable to the total prohibition of venting, and should be clearly stated.

4. It is not clear from the Proposed Rule when an operator must be in compliance with the prohibition. Section 3179.9 says that NTL-4A approvals "to flare or vent at a level above the 7,200 Mcf per month limit …, which are in effect as of the effective date of this rule, will continue in effect until [90 DAYS AFTER THE EFFECTIVE DATE OF THE FINAL RULE]." Does that mean that approvals to flare or vent at a level below the 7,200 Mcf per month limits will remain in effect in accordance with the 3 year phase-in set forth in section 3179.6? That would be preferable to the flat cut-off of all venting as soon as the Proposed Rule becomes effective that is suggested by the language of section 3179.6(a). Obviously, operators cannot be expected to cease all venting from one day to the next.

2. Setting limits on the flaring of associated gas

To address the waste of associated gas from flaring, the Proposed Rule proposes to "establish a limit on the average rate at which gas may be flared of 1,800 Mcf per producing well on a lease" per month. The limit will apply immediately to new wells, and after a two-year phase-in period to existing wells. For the following reasons, the proposed limit is arbitrary and should not be adopted by BLM.

As explained above, the limit is arbitrary as applied to operators with existing NTL-4A approval to flare above the limit, and to operators of new wells.

The limit is also arbitrary because it is based on outdated economic data. BLM apparently took its cue for the establishment of flaring limits from a 2010 GAO Study, which was entitled "Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared natural Gas Which Would Increase Royalty Payments and Reduce Greenhouse Gases" ("GAO Study").[37] As an explanation of the need for its rulemaking, BLM states that "GAO found that 'around 40 percent of natural gas estimated to be vented and flared on onshore Federal leases

[37] GAO-11-34 (Oct. 2010).

could be economically captured with currently available control technologies.'"[38] Using 2008, the RIA cites a GAO estimate that about 128 billion cubic feet of natural gas was either vented or flared from Federal leases, of which 50 billion cubic feet was economically recoverable.[39] This recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon monoxide equivalent emissions.

This reasoning, however, does not reflect the current state of the market. First, the average natural gas price for the full year 2008 was $8.85 per MCF, as compared to the spot price of natural gas in March of 2016 which is $1.40 on March 14, 2016.[40] This is an 84 percent drop in the price of natural gas since the 2008 time frame used in the RIA. Based on the 84 percent reduction in the price of natural gas, the $23 million dollar figure presented by the BLM would drop to $3.68 million.

If BLM chooses to proceed with adopting the limit in spite of the arbitrariness of the limit and its own lack of authority, then the following concerns need to be addressed.

1. Under the Proposed Rule, alternative limits may only be granted if the operator can demonstrate that complying with the required limits "would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves." But the flaring limits alone may not be the sole determining factor in a well's economic viability. The Proposed Rule imposes layers of cost through a variety of requirements – e.g., the cost of replacing high-bleed pneumatic controllers, the cost of developing and implementing a leak detection and repair (LDAR) program, the added administrative burden of recordkeeping and reporting for federal wells, etc. Operators don't make decisions about these costs in a vacuum; they are considered in concert. BLM should allow for similar considerations as part of the alternative flaring limit requirements. One factor alone may not be enough to render a well uneconomic, but the myriad and burdensome requirements of the Proposed Rule might when taken together. The total cost of

[38] 81 FR 6617.

[39] Government Accountability Office, *Federal oil and gas leases: Opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases*,. GAO Report 11-34, October 2010, at: www.gao.gov/new-items/d1134.pdf.

[40] Braziel, E. Russell, The Race To Liquids, Oil & Gas Finance Journal, August 1, 2010, on-line at: www.ogfj.com/articles/print/volume-7/issue-8/features/the-race_to_liquids.html; CNBC.com for March 14, 2016 natural gas price.

implementing the Proposed Rule is certainly relevant to an operator's determination about whether it can afford to continue to produce from a well, and the total cost of implementing the Proposed Rule should therefore be relevant to BLM in determining whether to grant relief from the Proposed Rule's requirements. Moreover, the granting of an alternative limit should not depend on a demonstration that without such a limit there will be "significant" abandonment of oil reserves. That would mean that to prevent the "waste" of some gas through flaring, BLM could, in effect, force operators to "waste" substantial amounts of oil and gas by leaving it in the ground.

2. There is no explanation on treatment of waste gas from the remote capture technology—i.e., after the NGLs are removed, the remaining gas goes to flare and should be considered unavoidable and not included in limits or royalty calculation. The North Dakota Energy and Environmental research committee evaluated remote capture technology. Its conclusion is summarized in the following: "New Technology Investigations. The Energy & Environmental Research Center." EERC conducted an assessment of alternative gas uses upstream of traditional gas-processing plants. The study investigated using associated gas for power production, transportation fuel, and chemical production, as well as analyzed small-scale gas processing to recover NGLs. Although intriguing, the economic viability of these alternatives was complicated by the distributed and transient nature of flared gas, requiring innovative approaches to effective implementation."[41] This reinforces the belief that the gas is not wasted but is an uneconomic byproduct of the oil production.

3. The flaring limits cannot be reasonably enforced with Federal and Non-Federal wells on the same gas sales line. Non-Federal well will make sales and block Federal wells, thus competitively ruining production on Federal land.

4. With respect to alternate flaring limits, no valuation of flared gas is provided. Flared gas cannot be valued the same as sales gas because it must properly account for implementation of a redundant gathering system. When these added costs are considered, the netback price of the gas is essentially zero.

[41] https://www.undeerc.org/bakken/Reduced-Gas-Flaring.aspx.

5. BLM proposes that under § 3179.8, "operators would need to estimate or measure all volumes of gas vented or flared" which includes "flaring of associated gas, and flaring that occurs during well drilling (proposed § 3179.101)…". This is technically infeasible. Gas flow meters require a steady stream of gas to be accurate. Drilling operations do not provide the requisite steady stream of gas required. Furthermore, gas rate meters will not work in the presence of liquids – an element often included in the gas stream from drilling operations. In sum, measuring the gas stream from drilling operations is technically infeasible and estimating the gas stream is a highly subjective process. Instead of relying on inaccurate and costly metering, operators should be allowed to use a GOR to calculate total produced gas or measure total produced gas then use calculation: (Total Produced Gas – Lease Use – Gas Sales). Based on our analysis, BLM's cost estimate for flare meters is extremely low. On any given day, an operator could temporarily lose access to natural gas sales and lines and be above 50Mcfd. Based on this reality, BLM's proposed requirements would necessitate a meter on every site production could be greater than 50 Mcfd. Even if sales are not lost, virtually every well will flare > 50 Mcfd at some point due to compressor maintenance, force majeure, and emergencies and would then have to measure. It appears BLM did not consider this factor when estimating the number of impacted sites. In addition, there is no measurement that will accurately measure the very big swings in flow. If flare meters are required for every flare that hits 50 mcfd at any point in time, nearly every flare will require a meter. And the vast majority of those meters will have zero flow most of the time, then spike during temporary periods of flaring. There is no meter on the market that can accurately gauge volumes at a spike period when generally it has no flow. BLM should consider more carefully examining their metering requirements so that meters are only required if 50 Mcfd is estimated for more than 60 days.

6. In many instances, oil and natural gas production and natural gas gathering systems are operated by separate companies. BLM's discussion of third party natural gas gathering systems in the Proposed Rule underestimates the complexity of the agency approval process even with a robus dialog between oil and natural gas producers and midstream system operators. Although companies can and do work together in good faith to ensure resources are developed efficiently and responsibly, market dynamics play an equally important role. A producer cannot

necessarily influence how a midstream operator builds out its gathering system, allocates available capacity, and plans its maintenance schedules, among other decisions. It is unrealistic to place the burden of complying with a standard on an operator that cannot control third party infrastructure. In order to accommodate the many situations that can arise when, despite good faith efforts, operators are unable to utilize gathering systems, BLM should provide adequate exemptions for lack of gathering capacity, maintenance schedules, and other force majeure situations.

This problem is particularly acute in areas like North Dakota. Gas gathering and processing infrastructure exists, but lacks capacity or where new development has occurred without pre-existing infrastructure. Where it is practical, producers will nearly always develop in areas near gas gathering systems. This allows maximum economic and environmental benefits. But it is not always practical to develop near this infrastructure—especially in very remote areas (such as certain parts of North Dakota). Producers do not always have control over how gas gathering infrastructure is used. For example, in some cases, midstream companies may curtail the capacity made available for an operator's associated gas or other constraints. In others, lease terms and other constraints require the resource to be developed on a certain timeline despite dedicated infrastructure. The Proposed Rule appears to assume that availability of gas gathering infrastructure alone will largely solve these problems. In our experience, this is far from accurate. Capacity constraints on existing infrastructure can be both temporary and long-term problems that are very complex to address. Producers and midstream companies work together to minimize capacity constraints but in a dynamic industry like oil and natural gas production, the goal of maximizing gas capture is a constantly moving target. The Proposed Rule risks shutting down significant portions of this industry, which is already strained by low commodity prices. Such consequences are likely to be borne disproportionately by smaller producers.

Further complicating matters, some wells may come online with a high initial production (IP) rate. In these instances, the large volumes of associated gas produced may overwhelm limited gas supply capacity. Operators are left with little choice but to flare that associated gas or risk damage to the reservoir of a highly productive oil well by choking it back. That could have significant economic consequences for operators as well as mineral owners, including the federal government.

If BLM fails to allow adequate provisions, operators would be forced to consider building out redundant gathering systems which is cost-prohibitive and creates added environmental impact through construction, or curtail production which would decrease royalty payments to the federal government and could potentially permanently damage otherwise productive reservoirs.

7. The proposed natural gas measurement requirements are potentially infeasible in certain situations. Low pressure vapors coming from production sites are difficult to measure, but are more easily calculated. BLM should allow operators to determine flaring volumes through calculation, which has proven to be accurate. Metering simply adds cost and logistical difficulties without providing environmental benefit or reducing waste.

8. By requiring that no flaring take place above a certain limit, the Proposed Rule gives pipeline companies unfair leverage to raise their pipeline usage rates. This has been demonstrated in Utah, which imposes a flaring limit similar to the one in the Proposed Rule.

9. We encourage BLM to defer to state flaring rules where such rules exist, like North Dakota, New Mexico and Texas. By doing so, BLM will create a clearer path for development while still utilizing standards that are protective of the environment.

3. Detecting and repairing leaks

The Proposed Rule would require operators to develop LDAR programs for 'all wells that produce natural gas, … including oil wells."[42] Operators would be responsible for inspecting for gas leaks on: 1) all equipment and equipment components at the wellhead; 2) all facilities that the operator operates[43]; and 3) all compressors located on the lease, unit, or CA that the operator owns, lease, or operates. BLM estimates that the requirement would affect up to

[42] *Id.* at 6685.
[43] What is meant by "facilities" is not clear. The term needs to be explicitly defined.

37,000-38,000 well sites per year. The requirement is objectionable for several reasons and should not be adopted.

1. The issue of leak detection and repair for existing equipment is an issue that will be addressed by EPA in the rule that it is now developing to address existing sources of air emissions from oil and gas operations, just as it has been addressed by EPA in its rule for new and modified sources of emissions. BLM has already stated that it "expects that the LDAR requirements ultimately adopted [by EPA] for new and modified well sites would be as effective in minimizing the volume of gas lost through leaks as the final BLM requirements" that BLM is proposing in the Rule, and that therefore compliance with the EPA requirements would satisfy BLM's requirements.[44] BLM has no reason to expect that "the LDAR requirements ultimately adopted [by EPA for existing well sites] would be [any less] effective in minimizing the volume of gas lost through leaks" than the requirements that BLM is proposing in the Rule for existing well sites. BLM's own cost-benefit analysis, even if it were accurate,[45] demonstrates that its LDAR requirement cannot be justified solely as a "waste" prevention measure. Therefore, instead of going to the trouble and expense of finalizing those requirements, only to have them supplanted by EPA's requirements, BLM should cease its efforts to develop an LDAR requirement.

2. Although BLM heavily touts the environmental benefits of the Proposed Rule, its proposal would create many negative environmental consequences. For example, in its Environmental Assessment, BLM claims the proposed LDAR program would require one to four truck trips per year to each of the roughly 38,000 wellsites impacted by the rule. This is likely understated given that many repairs could require multiple trips, and possibly multiple vehicles per trip, depending on the nature of the repair. This could add up to 150,000 truck trips or more, with many of these trips would be over many miles to remote locations and could have an impact on the local environment such as crop impacts for wellsites in agricultural areas and impacts to wildlife. Additionally, adverse weather could render many of these trips difficult or impossible at certain times of year.

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[44] *Id.* at 6648.
[45] See the attached economic analysis for an explanation as to why BLM's analysis is incorrect.

3. BLM acknowledges that its proposed approach "is similar to the requirements adopted by Colorado and Wyoming."[46] That being true, it should allow operators in those states to satisfy BLM requirements by applying their state-compliant programs on their federal leases. That would avoid duplicative efforts and unnecessary expense, while achieving substantially the same results in terms of preventing the "waste" of gas.

4. The Proposed Rule would impose sweeping, one-size-fits-all requirements in spite of BLM's acknowledgment of the following facts: 1) the Carbon Limits Study found that "about one-third of the facilities had no detectable leaks;"[47] 2) EPA found "higher volumes of fugitive emissions from gas wells compared to oil wells;"[48] 3) "[m]ultiple studies have found that a relatively small percentage of facilities are responsible for the majority of leaks and for most of the wasted gas;"[49] 4) "BLM believes [based on experience in the field] that there are systematic differences among operators' leak rates;"[50] and 5) most leaks are found in equipment that vibrates.[51] Given these facts, it is obvious that BLM's sweeping requirements do not achieve BLM's own goal of "reduc[ing] the most waste at the lowest cost."[52]

To achieve its goal, BLM should revise its requirements to focus on gross emitting components. The Proposed Rule should focus on: (1) the most common sources of leaks, such as valves, open-ended lines, and pumps, or "high motivated operation equipment;" and (2) only those components with the potential to operate at or above sales line pressure. This would allow operators to maximize the cost effectiveness of their LDAR programs by focusing the most resources on quickly identifying and addressing the largest leaks.

Providing operators flexibility in developing LDAR programs similar to directed inspection and maintenance (DI&M) programs tailored to their specific facilities or groups of facilities would provide significantly greater fugitive emissions benefits at a much lower cost than the type of rigid and inflexible program in the Proposed Rule. See Management of Fugitive

[46] *Id.* at 6647.
[47] *Id.* at 6646.
[48] *Id.* at 6649.
[49] *Id.* at 6648.
[50] *Id.*
[51] *Id.* at 6650.
[52] *Id.* at 6648.

Emissions at Upstream Oil and Gas Facilities, Canadian Association of Petroleum Producers (In the upstream oil and gas sector "[o]nly a small percentage of the equipment components have any measurable leakage, and of those only a small percentage contributes to most of the emissions. Thus, the control of fugitive emissions is a matter of minimizing the potential for big leaks and providing early detection and repair.") Accordingly, we strongly support a flexible approach. Allowing operators to focus monitoring efforts on the components that are most likely to leak, and those that are most likely to have the highest leak rates, maximizes both the emissions reductions and cost-efficiencies of an LDAR program.

5. <u>Section 3179.302 Approved Instruments and Methods</u> – For all practical purposes, the Proposed Rule would require the use of optical gas imaging devices ("OGI") for inspections conducted by operators that operate "500 or more wells within the jurisdiction of a single BLM field office."[53] However, OGIs may not function well in all situations. For example, an OGI is not a quantitative tool and, depending on the camera, it may also detect water vapor and heat signatures. An OGI camera survey may not always be able to tell an operator whether a repair is necessary, since it is not quantitative. During periods of overcast skies, high winds, or inclement weather, OGI technology is unable to effectively detect hydrocarbon vapors. In certain parts of the West, such overcast and windy conditions can persist for long periods during the winter, and as a result operators could likely spend considerable time and money repairing leaks of just water vapor. Lastly, OGI cameras are generally not intrinsically safe and would require a hot work permit in many instances. Due to these numerous technical and practical limitations, it would be inappropriate for BLM to adopt a leak threshold definition. We support BLM's decision to not include such a definition in its proposed rule.

Rather, the Proposed Rule should give operators the flexibility to select the ideal monitoring technology for their particular conditions. Instead of having to obtain BLM's approval before using something other than OGI, operators should simply be required to file with BLM a statement identifying the technology and certifying that it meets or exceeds the effectiveness of OGI in detecting leaks.

[53] *Id.* at 6685.

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

6. Section 3179.303 Leak detection inspection requirements - We strongly oppose an inspection schedule that varies in frequency. While we appreciate BLM's intent to create a performance-based program, in practice this approach will create a disproportionately large administrative burden while offering minimal environmental benefit. Instead, we urge BLM to implement a fixed annual inspection schedule.

BLM acknowledges the Carbon Limits Study that demonstrated that annual surveys "generally resulted in net benefits to the operator," and that quarterly surveys imposed net costs on the operator. Second, as BLM is well aware, EPA also concluded that "the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions…"[54]. Further, BLM admits that its proposed inspection requirements with "inspection frequencies that vary over time and across an operator's well sites" can be confusing.[55] Accordingly, instead of burdening operators with a set of confusing inspection requirements that will have small to negative net benefits, the rule should simply

[54] 80 Fed. Reg. 56636.
[55] 81 Fed. Reg. at 6648, 6650.

require annual inspections at all sites. Based on the results of those inspections, BLM should then evaluate its inspection requirements at the end of five years.

The Proposed Rule's LDAR inspection requirements take a one-size-fits-all approach that is impractical for many facilities. To treat a well that produces six barrels of oil per day like a centralized well pad with eight horizontal wells is unrealistic. Stripper wells producing less than 15 barrels of oil equivalent per day (boe/d) do not have the potential to emit at the same rate as larger producing facilities, and should therefore be exempted from the proposed LDAR requirements. Although BLM claims that LDAR at stripper wells will offer significant emissions benefit, industry experience indicates otherwise.

In the preamble of the Proposed Rule, BLM itself recognizes that a one-size-fits-all approach will likely not yield equitable costs and benefits. "EPA's emissions factors indicate generally higher volumes of fugitive emissions from gas wells, compared to oil wells. Assuming these emissions factors are accurate, this indicates that focusing more inspection resources on gas than oil wells would identify and save a relatively larger volume of gas at roughly the same cost." Yet BLM goes on to impose blanket requirements that treat all facilities as equals.

We agree with BLM's assessment that the requirement for OGI only applied to large operators with 500 or more wells per BLM field office. For small operators, the cost of an OGI or Method 21-based LDAR program would be particularly burdensome, and we urge BLM to retain this exemption in the final rule. In some instances, these small operators have only a few wells or wells with low production volumes; and therefore the cost of the equipment or implementing the program may vastly exceed the emissions being saved. As an alternative to expensive instrumental surveys, we recommend that BLM allow for soap bubbles as a potential screening method (only where appropriate, considering the caveats in EPA Method 21, Section 8.3.3.1). EPA already recognizes the effectiveness of soap bubbles in its Method 21, Section 8.3.3 procedure.

We also urge BLM to clarify the phase-in period for its proposed LDAR program. In order to allow companies sufficient time to develop LDAR programs, train staff, and procure equipment, we suggest a 12-month phase-in. BLM should also provide a variance for state LDAR programs as being sufficient to satisfy BLM's requirements.

BLM also solicits comment on the use of third-party LDAR inspections (81 FR 6649) which we strongly oppose. Under no circumstance should BLM impose this needless burden that is devoid of any environmental benefit. BLM does not have unfettered authority to promulgate regulations that could force the entire industry to change the way in which it designs and operates its facilities or reports information—particularly where the rule has neither demonstrated the need to do so, nor discussed the environmental benefits to be obtained or the costs to be incurred. BLM's LDAR program must be reasonable with respect to its requirements and its consequences. On balance, we do not believe requiring third party certification of LDAR is reasonable.

7. <u>Section 3179.304 Repairing leaks</u> – The Proposed Rule would require operators to "repair any leak not associated with normal equipment operation as soon as practicable, and in no event later than 15 calendar days after discovery, unless good cause exists for repair requiring a longer period."[56] Given the fact that repairs often cannot be made within 15 days due to weather conditions or the availability of parts, BLM should adopt a more realistic repair window of 30 days, with the possibility to extend for an additional 30 days, in the event that parts are unavailable. This would significantly reduce the paperwork required, and that benefit would clearly outweigh the detriment that might be caused by whatever small amount of gas might leak from a particular component during the extra 15 days. We also ask that BLM clarify that decisions regarding feasibility due to weather or "good cause" allow for operator discretion, as they best understand when weather or other conditions can render repair work infeasible or hazardous.

Further, as most companies do not allow hot work without shutting in production, the Proposed Rule should state that where shut-in is required before a repair can be made, the operator shall make the repair immediately after the next scheduled shutdown, but in no event

[56] *Id.* at 6686.

later than six months after the leak is detected. EPA made a similar allowance in its New Source Performance Standards (NSPS) Subpart OOOO regulations, which provide that "[d]elay of repair for equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown."

8. Section 3179.305 Leak detection inspection recordkeeping – The requirement that the report include a "description of the leak" is ambiguous and superfluous. Requiring operators to document the first attempt at repair is also redundant. All that really needs to be recorded is the component on which the leak was found and the fact that it was repaired.

4. Replacing high-bleed pneumatic controllers

The Proposed Rule would require operators to replace approximately 15,600 existing high-bleed pneumatic controllers—i.e., existing pneumatic controllers with a continuous bleed rate greater than 6 standard cubic feet per hour--with low-bleed pneumatic controllers within one year of the effective date of the rule. The requirement is objectionable for several reasons and should not be adopted. If BLM decides to adopt a replacement requirement in spite of the objections noted above, the requirement should be revised as set forth below.

1. The preamble states that the Proposed Rule would require the replacement of pneumatic high-bleed controllers with low-bleed controllers. The Proposed Rule should make clear that high-bleed controllers may also be replaced with intermittent controllers because they are not a significant source of emissions. A 2014 study conducted by Oklahoma Independent Producers Association (OIPA) examined 205 producing wells and 680 pneumatic controllers.[57] The study determined that on average, intermittent vent controllers emitted 0.40 standard cubic feet of gas, a miniscule amount. OIPA's analysis found that prior estimates underestimated the number of vent controllers at visited sites, but overestimated emissions, and overestimated both the number of continuous bleed controllers and their emissions. OIPA's analysis provides further support for allowing intermittent controllers.

[57] Pneumatic Controller Emissions from a Sample of 172 Production Facilities, Oklahoma Independent Petroleum Association, November 20145.

2. Operators should be given at least two years to replace their high-bleed pneumatic controllers. It will take that long for companies to plan accordingly, budget funds to support implementation costs, order and purchase equipment, and complete installation of the replacement equipment. Indeed, given the sudden and significant demand for new controllers that will be created by BLM's replacement requirement, it is highly likely that current supplies will not be adequate to meet the demand and that operators may face significant delays in obtaining the new equipment.

3. The Proposed Rule states that an operator may be exempted from the replacement requirement for a particular controller if it notifies BLM and BLM agrees that compliance with the replacement requirement "would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease."[58] This is the standard that was developed to justify an exemption from the flaring limits for all oil wells on a lease and is not appropriate for use here. Instead, it should be based on the cost of replacing a single pneumatic controller.

4. BLM substantially underestimates the cost of replacing pneumatic controllers in its proposed rule by keeping the focus of its analysis too narrow. The cost of this requirement is not limited to the cost of installing a new controller. There are significant labor costs as well as the costs of downtime and lost production during installation to consider. The Proposed Rule would also lead to a dramatic increase in demand for controllers, particularly given the short implementation window. This could potentially lead to difficulties for manufacturers' ability to meet the new demand, which would in turn drive prices of the device up. There are further downstream effects to consider too, as the increased requirements to capture and route gas will lead to additional demand for pneumatic controllers to manage those systems. This in turn will further drive demand (and therefore costs) higher.

[58] *Id.*

5. BLM should allow for use of high-bleed pneumatic controllers where they remain necessary for safety reasons. EPA makes such an allowance in its proposed NSPS OOOOa and we recommend that BLM do the same.

5. Replacing certain pneumatic pumps

The Proposed Rule would require operators to: 1) replace existing pneumatic chemical injection pumps and pneumatic diaphragm pumps with zero-emissions pumps, or 2) route the emissions from those pumps to a flare device on-site. BLM estimates that 8,775 pumps would be subject to the requirement. The requirement must be met within one year of the effective date of the rule. The requirement is objectionable for several reasons and should not be adopted.

If BLM chooses to adopt a replacement requirement in spite of the general objections noted above, then the requirement needs to be amended as set forth below.

1. The Proposed Rule requires replacement of all chemical injection or diaphragm pumps regardless of the amount of their actual emissions. If there is to be a replacement requirement, BLM should exempt pumps with *de minimis* emissions. Such pumps would include pumps that are: 1) not in constant service—i.e., operate less than 2,160 hours/yr; 2) portable; 3) routed to a process; or 4) whose emissions are less than 6 scfh.

2. The Proposed Rule states that a pump may be exempt from the replacement requirement if the gas that would normally be vented is routed to a flare device. However, flaring gas from pneumatic pump exhaust may not technically feasible in certain situations. Thus, many pumps subject to the rule will need to be replaced. BLM needs to reflect that fact in its cost-benefit analysis. BLM relies heavily on WDEQ's Upper Green River Basin (UGRB) Existing Source Rule pneumatic pump requirements to justify the proposed requirements in § 3179.202. BLM fails to acknowledge that such requirements were promulgated by WDEQ to regulate emissions in an ozone nonattainment area. It is unacceptable to apply a standard for a specific nonattainment area nationwide. It is also important to note that the UGRB is a unique basin that supports a multi-well pad approach to development. Because of this supported

development, it is easier for operators to route pneumatic pumps to combustion devices than it will be in other basins, nationwide.

Both in the UGRB and nationwide, not all pneumatic pumps can be effectively routed to an existing control device. Accordingly, operators will have to install a control device specific to pneumatic pump emissions. Take, for example, natural-gas fired piston pumps (i.e. pneumatic methanol injection pumps) located at the wellhead. Pneumatic methanol pumps at the wellhead are far from where existing combustors are typically located at a site (e.g. at the production equipment and /or storage vessels). As a result, there will be insufficient pressure from the exhaust of the pneumatic pumps to be routed back to the combustor. Operators will not be able to control emissions from these pumps with existing controls.

3. Operators should be given three years to comply with the replacement requirement. It will take that long for companies to plan accordingly, budget funds to support implementation costs, order and purchase equipment, and complete installation of the replacement equipment. Indeed, given the sudden and significant demand for new zero-emission pumps that will be created by BLM's replacement requirement, it is highly likely that current supplies will not be adequate to meet the demand and that operators may face significant delays in obtaining the new equipment. Operators may have hundreds of natural gas driven pneumatic pumps in each basin. One year is an insufficient amount of time to evaluate each pump, order and install replacement pumps or control devices and confirm proper operation. BLM relies on Wyoming's UGRB Existing Source Rule to justify the proposed requirements of § 3179.202 in the preamble. The UGRB Existing Source Rule was effective on June 30, 2015 and provided operators until January 1, 2017 to replace all pneumatic pumps with zero-emissions pumps, route such equipment to a line or closed loop system or route emissions to a control device. The UGRB Existing Source Rule covers a more sensitive area (i.e. an ozone nonattainment area) than BLM's nationwide rule and still provided a year and a half for compliance. A three year deadline to comply with § 3179.201 will give operators a more reasonable amount of time to ensure compliance. Increased compliance will decrease the "waste of natural gas" and conserve BLM inspection and enforcement resources upon final rule implementation.

4. The Proposed Rule states that an operator may be exempted from the replacement requirement for a particular well if it "provides an economic analysis that demonstrates, and BLM agrees, … that installation of a zero-emissions pump would impose such costs as to cause the operator to cease production and abandon significant recoverable oil reserves under the lease." As stated above, this standard is inappropriate. Instead, it should be based on the cost of replacing a single pneumatic pump.

6. Limiting venting from storage vessels

The Proposed Rule requires operators within six months to "route all tank vapor gas" that is vented from existing storage vessels that have "a rate of total VOC emissions equal to or greater than 6 tons per year" "to a combustion device or continuous flare, or to a sales line."[59] BLM estimates that the requirement "would affect about 300 existing storage vessels on BLM-administered land." The requirement is objectionable for several reasons and should not be adopted.

BLM's decision to use VOCs as a proxy for methane emissions is unreasonable. Generally, when crude oil has reached storage tanks it has undergone separation, where natural gas is removed from the product stream and diverted to sales. Although there will be some residual gas entrained in the crude oil, the vast majority of associated methane has been removed. Therefore BLM's calculations about the benefits of storage tank controls, which rely heavily on the social cost of methane (SCM), are inaccurate. BLM also underestimates the number of affected storage vessels in its analysis of the provisions. One single operator estimates that it will have approximately 100 storage vessels impacted by the proposed

If BLM chooses to adopt the requirements in spite of the general objections noted above, then the requirements needs to be amended as set forth below

1. The cost of controlling the vapors from existing storage vessels is much higher than for new storage vessels, and the life of an existing storage vessel is shorter. Therefore, the emissions

[59] *Id.* at 6685.

threshold for controlling the gas vapors from existing storage vessels should be higher than the 6 tons per year standard established by EPA for new storage vessels.

2. BLM has failed to consider the potential negative effects on climate change that may result from the control of tank vapors. The installation of combustion controls to reduce methane emissions from storage tanks may in fact increase the overall GHG emissions impact as a result of dramatically increased CO_2 emissions. The example provided for a typical storage tank battery producing oil from the Bakken formation in North Dakota demonstrates that the installation of combustion controls increases the overall GHG impact by 228 percent. Considering that the Proposed Rule is a component of the President's White House strategy for climate change, it should clearly result in a net benefit in GHG emissions which BLM has failed to demonstrate.

3. Given all of the other requirements that would be placed on operators by the Proposed Rule, operators should be given at least one year to meet the routing requirement for storage tanks, and should be given six months to determine the rate of emissions from their storage vessels. Wyoming's UGRB Existing Source Rule was effective on June 30, 2015 and provided operators until January 1, 2017 to control or route to a sales line all applicable storage vessels. The UGRB Existing Source Rule covers a more sensitive area (i.e. an ozone nonattainment area) than BLM's nationwide rule and still provided a year and a half for compliance. In addition, BLM should clarify what is meant by a "new source of production." Is the rule intended to require an operator to determine the rate of emissions from a storage vessel whenever it receives production from a new well on the same lease as the well[s] from which it has previously received production?

4. The Propose Rule appears to blur the line between a storage vessel and a battery of storage vessels. EPA created some similar confusion in its 2012 NSPS OOOO rulemaking, which it later clarified in its "OOOO 1.75" amendments. NSPS OOOO provides that a "storage vessel affected facility" is an individual storage tank. BLM's Proposed Rule, however, defines a storage vessel as "a crude oil or condensate storage tank or <u>battery of tanks</u> that vents, or is designed to vent, to the atmosphere during normal operations." (emphasis added). The emission

control applicability threshold in BLM's Proposed Rule is defined by the PTE of a crude oil or condensate tank or a "battery of tanks," indicating that operators must determine applicability based on each tank's PTE and, where more than one tank is present, the sum of the PTE associated with multiple tanks in a battery. In light of BLM's definition of "storage vessel," BLM's proposed regulations for existing storage vessels is more stringent that EPA's control requirement for new and modified storage vessels. We strongly encourage BLM to maintain consistency with EPA and apply its storage vessel requirements to individual vessels, not storage vessel batteries.

Applying BLM's requirements to storage vessel batteries would dramatically increase the cost, complexity of requirements, and the number of vessels affected. Such a significant shift would likely necessitate BLM revisiting its cost benefit analysis here. One member reports having at least one basin with over one hundred applicable storage vessel facilities. With an estimated cost of $30,000 - $40,000 to purchase and install emission control equipment, the cost to comply with § 3179.203(c) appears overwhelming. Given this, it would appear BLM's estimate of 300 affected facilities is significantly understated.

A regulatory scheme, like the one BLM has proposed, that imposes more stringent requirements on existing tanks, which are a less significant source of emissions, than EPA imposes on new tanks makes no sense. We therefore urge BLM to forego the regulation of existing storage vessels. In the event BLM moves forward with its regulations, we recommend BLM revise the definition of storage vessel in § 3179.3 to read:

> a crude oil or condensate storage tank that vents, or is designed to vent, to the atmosphere during normal operations.

7. Limiting emissions from downhole well maintenance and liquids unloading

The Proposed Rule "would prohibit new wells from unloading liquids by simply purging the wells."[60] For both new and old wells, operators would be required to use "practices that maximize the recovery of gas for sale and must flare gas not recovered." BLM estimates that the requirements will impact 1,550 existing wells, as well as an undetermined number of other wells that are currently equipped with plunger lifts but not "smart" automation. The requirements are unreasonable and should not be adopted.

BLM bases its requirements on its belief that "[r]ecent technological developments allow liquids to be unloaded with minimal loss of gas," and that it is therefore "reasonable to expect operators to use these available technologies to minimize gas losses."[61] However, BLM's belief is at odds with the conclusion recently reached by EPA in its consideration of new source performance standards for VOC emissions from liquids unloading activities. After an exhaustive examination of the issue of emissions from liquids unloading, EPA concluded as follows:

> Data reviewed also show that liquids unloading events are highly variable and often well-specific. Furthermore, questions remain concerning the difficulty of effective control for those high-emitting events in many cases and concerning the applicability and limitations of specific control technologies such as plunger lift systems for supporting a new source performance standard.[62]

As a result of its analysis, EPA declined to regulate liquids unloading in its proposed NSPS OOOOa, as did the state of Colorado upon adoption of Regulation 7. The Colorado Department of Public Health and Environment (CDPHE) recognized that operators need flexibility to employ best management practices on a well-by-well basis.[63] CDPHE went on to recognize that automated plunger lifts are not pollution control devices and are not used in the field unless the

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[60] *Id. at* 6655.
[61] *Id.*
[62] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56593, 56645 (Sept. 18, 2015) (proposed rule).
[63] *Well Liquid Unloading Frequently Asked Questions*. CDPHE. August 17, 2015.

well design, geologic conditions, and gas content are appropriate for it. Given the significant difference of opinion between BLM and EPA on the feasibility of controlling emissions from liquids unloading, BLM should postpone adopting any liquids unloading requirements until that difference is resolved. The federal government should speak with one voice on this important issue.

We have serious concerns with the proposed liquids unloading requirements, particularly with the prohibition of well purging. The proposed Best Management Practices (BMPs) may not be adequate as a well declines, and later in its productive life, even a well classified as "new" under the Proposed Rule may need to be purged. Plunger lift systems are effective only to a point and do not serve as a panacea for well purging. Plunger lift systems will not be installed on all new gas wells at initial production. A plunger lift generally will not be used until the well has been on production for some time. At that point in time, if a plunger lift were installed at initial production, it would have to be replaced due to age. Differentiating between new and existing sources in this category is not logical as wells generally do not unload until later in life. We ask BLM to consider the following example:

Pipeline companies put back pressure valves on their pipelines. These are typically set at very low pressures in areas with low pressure gathering systems. The purpose of these valves is to protect the pipeline from surges in volume or pressure that in the opinion of the pipeline company might damage their line or metering equipment.

In these same areas, plunger lifts and intermitters are also often used. Intermitters are systems using pressure, or timer, controls that allow well pressure to build up in a well and then they open a control valve on the flow line based on a set time or pressure to allow the well to surge and flow at higher rate than the well could maintain on a continuous basis thereby carrying fluid to surface that would not be carried out if the well were flowing at the rate it can support on a continuous basis. Plunger lifts also use intermitters with the addition of a small plunger made of metal or a synthetic material that travels from a resting point on a stop in the tubing near the top of the wellbore perforations to the surface up the tubing. During each of these cycles, fluid and gas is pushed the hole and is pushed to the top of the tubing by well pressure. The plunger is retained in the wellhead for a short period by pressure and flow. After a certain set period of time, or at a set pressure, the control valve on the flow line closes. After the valve closes, the pressure build-up cycle begins again. In the case of a plunger lift, the plunger drops back down the tubing to a spring loaded stop set in the tubing near the top of the perforations and it sits on the stop until the control valve on the flow line opens for the next cycle. In both cases, pressure builds and fluid that will be carried out of the hole enters the well during the shut-in period. Both of these are automatic unloading devices commonly used, and sometimes used in association with soap sticks and surfactants.

These pipeline backpressure valves cause problems with automatic unloading systems. When the well surges when an intermitter opens there is a higher initial pressure and gas rate with a duration of a few seconds to a few minutes. The volumes actually produced in the first minute would be small. The rate starts high but drops very quickly so the amount of gas flowing at the end of a minute may one quarter of the initial rate at the beginning of the plunger lift cycle or less. Very little gas is produced in the first minute or so of flow. Some of these systems cycle as few as one to three times per day. A more typical number of cycles might be eight to twelve times per day.

The increased gas rate and pressure at the start of a cycle would typically be inadequate in gas volume to make the sales line pressure up sufficiently to damage the line, even with poly line systems. However, the surge pressure causes the pipeline backpressure valve to shut in many cases because the valve just sees the pressure, it cannot detect the surge volume and associated pressure is inadequate to damage the line. Many of these valves have to be manually reopened. If one shuts it likely means a loss of production for 24 hours and sometimes more plus a fee to reopen them in some cases. Therefore operators in some areas use what is commonly known as a divert valve or “B Valve”.

These diversion valves open at the beginning of a intermitter cycle and divert all or a portion of the gas flow depending on how they are designed into a tank, typically for a few seconds to less than a minute, although some may run longer. They bleed the surplus pressure and gas to a storage tank until the pressure drops enough to allow the gas to enter the pipeline without tripping the pipelines backpressure protection valve. They can be controlled on a set time or pressure. After a certain time period or at a certain pressure the divert valve closes directing all the gas into the gathering line through the sales meter.

These systems are fairly common throughout low pressure gas and oil producing areas with low pressure gathering systems and they allow substantial natural gas, oil and condensate volumes to be economically produced when taken in aggregate over hundreds to thousands of wells in an area. They allow these reserves to be produced from formations where no other system would allow the economic production of these reserves. Their gas losses are minimal on a day-to-day basis and the operators are highly motivated to keep the diversion valves open only long enough to get the pressure low enough to get it into the line without causing the pipeline backpressure valve to shut, as they are losing revenue on every bit of gas going into the tank. The variety of these situations makes it difficult to suggest a simple requirement, which further underscores the inappropriateness of attempting to regulate liquids unloading.

These kind of systems result in minimal gas losses. We suggest an outright venting exemption from the regulations for plunger lift and intermitter systems using a divert valve unless the divert valve is found by BLM to not be closing at all, or in a reasonable period of time, and the operator fails to correct the problem within 5 days or notice being received from the BLM. Shutting the well in until repairs or adjustments could be made would be considered compliance with the 5 day rule.

The Proposed Rule also fails to describe the information collection expectations for subsequent unloading events by well purging at such wells. We would object to subsequent purging events leading to additional information collection requirements that aren't expressly state in the Proposed Rule. Requiring operators to document and notify BLM of all subsequent purging events will be unreasonable for operators and is unnecessary for the proper functioning of BLM. Well purging by liquids unloading is standard industry practice, with individual operators commonly reporting hundreds of liquids unloading events per year. Having to document and notify BLM of all purging events would be extremely burdensome for operators and would be unnecessary for the proper functioning of the BLM because operators are already required to report unloading events under certain state programs (e.g., Wyoming) and pursuant to EPA's Greenhouse Gas Reporting Program. Furthermore, the deluge of notices BLM will receive if all purging events must be reported will overwhelm agency resources and prevent BLM staff from focusing on more important duties.

The Proposed Rule states that "[b]efore [an] operator purges a well for the first time after effective date of this section, the operator must document that other methods [of liquids unloading] are technically infeasible or unduly costly." This is an unreasonable requirement. As BLM notes, "operators must remove or 'unload' the liquids to maintain or restore production."[64] The rule should not require operators to immediately halt their maintenance or restoration efforts for an indefinite period of time while the feasibility and cost of other methods of liquids unloading besides purging are evaluate. Instead, operators should be given at least one year following the effective date of the rule before the documentation requirement must be met for any particular well. That will give operators adequate time to plan for the implementation of the requirement without bringing a halt to their ongoing maintenance or restoration efforts.

The Proposed Rule prohibits all "liquids unloading by well purging" for wells "drilled after the effective date" of the rule. Given the variety of factors from well to well and from field to field that may affect the technical feasibility and cost of using methods other than purging for liquids unloading, operators should be given the flexibility to employ best management practices in a fit-for-purpose manner based on the specific design, casing configuration, geology, and other factors. The state of Colorado acknowledged that need and BLM should as well. BLM's conclusion that "the alternative technologies discussed above [in 81 FR 6654-6655] now generally make well-purging unnecessary" is incorrect. Therefore, the prohibition on purging of new wells is infeasible.

The prohibition on purging will also require well swabbing or other maintenance operations. Swabbing is time-consuming, expensive, results in lost production due to well downtime, and still requires venting in the form of well blowdowns. Well blowdowns must occur before swabbing operations in order to depressurize the system and allow for safe working

[64] 81 Fed. Reg. at 6654.

conditions. The result is that BLM's prohibition on purging will not eliminate emissions from liquids unloading; it simply displaces them to another process while simultaneously adding cost that detrimentally impacts operators and royalty owners. This problem is further compounded because swabbing operations or similar maintenance may need to be done more frequently, again adding emissions and unnecessary costs.

8. Limiting emissions from well drilling and completions

The Proposed Rule would effectively prohibit the venting of any gas that reaches the surface during drilling and certain well completion operations. The gas must instead be captured and sold, flared, used in operations on the lease, or injected. These prohibitions are objectionable for several reasons.

1. Both sections 3127.101 and 102 require that gas that cannot be captured and sold or used in operations on the lease must either be flared or injected. As explained above, this preference for flaring (and injecting) over venting is not a "waste" prevention measure, as it does not prevent any "waste" of gas; instead, it is solely intended to reduce methane emissions out of a concern for the effect such emissions may have on climate change. The requirement that gas that is not captured and sold or used on the lease be flared or injected must therefore be deleted from the Proposed Rule. Moreover, as not all gas will be capable of being economically captured and sold or used on the lease, the Proposed Rule must state that gas that cannot be economically captured and sold or used on the lease may be vented.

2. Section 3179.101 effectively prohibits any venting of gas that reaches the surface during drilling. But achieving a no venting standard is not technically feasible in all circumstances, particularly when the gas reaches the surface through gas in solution, entrained gas or unplanned gas kicks. Gas in solution or entrained gas may be of insufficient volumes to burn continuously even after processing the drilling mud through a gas buster and sending the gas to flare. The gas will go to the flare but may not burn resulting in venting to the atmosphere. Gas from kicks in deeper formations goes to flare after separation in the gas buster but gas constituents such as high CO2 may prevent the gas from burning. Drillers must circulate

the gas out of the well to maintain control and venting is the only solution when gas quality is incombustible. Shallow gas kicks create unique circumstances. Shallow kicks occur when drilling surface hole without conventional BOP equipment. In areas of known shallow gas, a diverter with extended blooie lines is installed to prevent gas from accumulating under the rig in the event shallow gas is encountered. In general, it is not possible to shut in the well due to weak formations and controlling the influx requires diversion away from the rig as quickly as possible. The control method for shallow gas is to pump at the highest rate possible to raise the equivalent circulating density and control the influx. The high velocity mixture of gas, fluid and cuttings is not conducive to separation in a vessel to separate gas from the liquids and solids. The only safe solution is to vent to maintain control of the well.

3. Section 3179.102 effectively prohibits any venting of gas that reaches the surface during well completion and post-completion, drilling fluid recovery, or fracturing or refracturing fluid recovery. BLM should clarify, for fracturing and refracturing, that "gas reaching the surface" refers to the flowback following hydraulic fracturing and refracturing. Meeting a no venting standard is not technically feasible for flowback. Until a two or three phase separator can be operated, the only option for flowback is venting. Moreover, in fields with small volumes of associated gas like the Permian Basin, operators may be unable to run a two or three phase separator, and in fields that produce heavier crudes like Utah's Uinta Basin, operators may also not be able to run two or three phase separators. EPA's regulations allow venting from flowback until a gas/liquid separator can be operated so that sufficient gas can be captured and sent to a flare or put to beneficial use. BLM must allow venting in this circumstance as well.

4. BLM should also exempt wells with less than 300 scf per stock tank barrel of oil produced and wells with artificial lift equipment from the no venting standard, just as is done in EPA's regulations. We also encourage BLM to allow for pilot lights to be used on flares for drilling and completion operations in order to accommodate the variable quality and volume of associated gas that is produced during these processes.

5. BLM should not promulgate requirements for well completion operations following fracturing or refracturing as they duplicate EPA's NSPS Subpart OOOO and proposed OOOOa.

Subpart OOOOa will become applicable to each well completion with hydraulic fracturing or refracturing for all new gas wells and for all new oil wells with a GOR greater than 300 scf of gas per barrel of oil produced if NSPS OOOOa is promulgated as proposed. New wells are already covered by a specific NSPS, including requirements for emission controls, monitoring, recordkeeping and reporting. BLM will not benefit from any additional "waste" recovery by including their own well completion requirement.

6. EPA's OOOOa already includes recordkeeping and reporting requirements for compliance with the control requirements from flowback following hydraulic fracturing or refracturing. States have primacy to enforce NSPS regulations, and there are penalties for non-compliance. No additional compliance assurance will be achieved by requiring operators to submit a Sundry Notice to BLM stating compliance with NSPS OOOOa

9. Requiring the development of waste minimization plans

Section 3162.3-1 would require operators "[w]hen submitting an Application for Permit to Drill an oil well" to "also submit a plan to minimize waste of natural gas from that well."[65] In their plans, operators would be required to "set forth a strategy for how the operator[s] will comply with the requirements … regarding control of waste from venting, flaring, and leaks and must explain how the operator[s] plan to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible."[66] Although the waste minimization plans would not be enforceable, "[f]ailure to submit a complete and adequate waste minimization plan [would be] grounds for denying or disapproving an Application for Permit to Drill."[67] The proposed requirement is objectionable for several reasons and must not be promulgated.

1. <u>Requiring waste minimization plans is unnecessary</u> – Requiring waste minimization plans is not necessary to achieve BLM's stated goal and is therefore not a "reasonable precaution" against "waste" of gas and is beyond BLM's authority to impose under the MLA.

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[65] Waste Prevention, Production Subject to Royalties, and Resource Conservation,81 Fed. Reg. at 6679.
[66] *Id.*
[67] *Id.*

BLM "believes that requiring submission of a waste minimization plan would ensure that as an operator plans a new well, the operator has the information necessary to evaluate and plan for gas capture."[68] In other words, BLM is assuming that unless operators are required to gather certain information that they will need to comply with the venting and flaring limits, they will not do so. This is an insupportable assumption. Operators routinely conduct extensive planning about the current and future availability of infrastructure in their development plans for the express reason of minimizing flaring and maximizing gas capture.

Moreover, in order to comply with the venting and flaring limits, operators will of necessity have to plan how they will do so, even if there is no requirement to develop a waste minimization plan for submission to BLM. In other words, the existence of the limits themselves will motivate operators to plan; they will not need to be required to plan by BLM.

In addition, operators are fully capable of identifying what information will be needed to prepare their plans. Thus, having to generate and collect the information required by the Proposed Rule and then submit it in a prescribed format to BLM for review will serve no useful purpose. Preparing the plan for BLM will simply be a needless bureaucratic exercise that will waste the time and resources of operators in preparing the plan, as well as the time and resources of BLM in reviewing the plans to determine if they are "adequate and complete."

BLM states that the information required in waste minimization plans is comparable to the information that the North Dakota Industrial Commission ("NDIC") requires in gas capture plans. *See* 81 FR at 6642. However, the NDIC limits the amount of information that operators must provide from midstream companies with which they have no contractual relationship. For gas capture plans in North Dakota, operators simply relay information provided to them from the specific midstream company that is contracted to take that specific operator's gas. An operator must have a pre-existing contract with a gathering company in order for that company to take the operator's gas and to provide the operator the information requested by the NDIC. However, in the Proposed Rule, BLM seeks information operators do not have and may not be able to collect

[68] *Id.* at 6642.

because no contractual relationship exists, or are based on dedications that specific operators cannot use..

2. <u>Requiring waste minimization plans for venting and leaks is unnecessary</u> – The Proposed Rule would prohibit venting, except in specified circumstances, and would require the development and implementation of a Leak Detection and Repair Program. Thus, requiring waste minimization plans to address what will be done to minimize venting and leaks is not necessary since BLM is already prescribing what those actions are to be. BLM should clarify that waste minimization plans need address only how the operator intends to comply with the flaring limits in areas with known capacity issues.

3. <u>Requiring waste minimization plans will further slow an already slow APD approval process</u> – Waste minimization plans will not be enforceable, but a failure to submit an "adequate and complete" plan will be grounds for denying an APD. BLM will therefore have to review each plan before it can approve an APD, thus slowing down the APD approval process, which already often takes more than a year to complete. BLM should not assign itself a new task when it has demonstrated that it is not capable of performing the tasks it already has in a timely manner, nor should it assign itself a new task without establishing a deadline by which it is completed and without demonstrating that it will have the resources to meet that deadline.

Moreover, because it already takes so long to get an APD approved, the information in a waste minimization plan may well be stale by the time the APD is approved, and will thus serve no useful purpose. On average, it takes BLM three to six months to approve an APD on federal lands and 12 to 18 months to approve an APD on Indian lands. The difference with NDIC's gas capture plan is that the NDIC approves APDs within 15-45 days and meets with midstream companies on a regular basis.

By the time BLM approves an APD, most of the information BLM has requested will be out of date. Moreover, some information BLM is requesting in the waste minimization plans is not information an exploration and production company has at the time of submitting an APD. Examples of highly speculative and variable data include the anticipated daily capacity of the pipeline at the anticipated date of first gas sales from the proposed well and the anticipated gas production rates of a proposed well. The waste minimization information collection requirement does not help exploration and production companies better prepare to comply with proposed flaring limits. It will only act to memorialize information that is outdated by the time the APD is approved by BLM or request information the operator cannot know. It is difficult to find any value in outdated and/or obsolete information supplied to BLM at the time of the federal APD submission. The requirement to create and submit waste minimization plan must be removed or drastically modified in the Proposed Rule.

4. Waste minimization plans should not be required to contain confidential and unnecessary information - The information that must be included in a plan pursuant to section 3162.3-1(j)(4)(i-iv and vi), (5)(ii-iv), and (6) is confidential business information and should not be required to be included in a plan. Moreover, the information that must be included in the plan pursuant to section 3162.3-1(j)(4)(i-iv and vi) is in the control of the pipeline companies. Thus, even if it were not confidential, operators would likely not be able to obtain the information. BLM should not demand confidential business information in the form of decline curve projections, price, forecasts, anticipated pressures, etc., particularly from publicly traded companies. Also, operators will not be able to share plans for expansion of pipeline capacity for the area that includes the proposed well, as anticipated in the Proposed Rule, unless the expansion has been publicly announced.[69] BLM has no utility for this information, and if there was any utility, it would not be operators who could provide it.

Some of the information that BLM would require in a waste minimization plan is not necessary to achieve the purpose of the plan, which is to "set forth a strategy for how the operator will comply" with the flaring limits. For example, to achieve that purpose, an operator does not need to identify for BLM "all existing gas pipelines within 20 miles of the well," and "the location and name of the operator of each gas pipeline within 20 miles of the proposed well;" it only needs to identify the pipeline to which it intends to connect. The Associations would argue that information about existing pipelines in an areas is, as a practical matter, irrelevant because BLM cannot force an operator's gas to be delivered to a nearby pipeline

[69] *See* § 3162.3-1(j)(4).

owned by a third party gas gatherer where there is no contractual relationship, except after a full hearing pursuant to 30 U.S.C. 185(r)..

5. Waste minimization plans should not be required for every new oil well – BLM should clarify that waste minimization plans only need to be prepared for new oil wells with associated gas on leases that do not already have an easily-accessible pipeline connection. Further, operators should be allowed to develop and submit plans that cover multiple wells, especially for multi-well pads that will utilize a common pipeline tie-in point.

6. Requiring an alternative on-site capture approaches is not necessary – Each waste minimization plan must "explain how the operator plans to capture associated gas upon the start of production."[70] That explanation will necessarily include an explanation of any "on-site capture approach" that the operator intends to use other than connecting to a pipeline. Thus, unless the operator is claiming that capture by pipeline or some on-site method is not economic, there is no need for the requirement in section 3162.3-1(j)(7) that the operator prepare an "evaluation of alternative on-site capture approaches."[71]

BLM has identified the areas where high rates of flaring are taking place, notably, in the Bakken and Permian basins. Given that many other areas with extensive federal minerals, such as Utah's Uinta Basin and California's San Joaquin Valley, do not have high levels of flaring, requiring waste minimization plans in those areas would be a pointless bureaucratic exercise. It is simply common sense that BLM should not require the expenditure of time and resources to prepare plans in area that do not have a problem with high levels of flaring.

10. Section 3179.10 – Other waste prevention measures

Section 3179.10 states that if gas capture is not yet available on a given lease, BLM may "exercise existing authority to delay action on the APD for that lease." The preamble cites 30 USC 187 and 225 as this existing authority. BLM's position is apparently that its authority to prevent "waste" allows BLM to indefinitely suspend action on an APD until gas capture

[70] *Id.* at 6679.
[71] *Id.*

infrastructure is available. Even assuming the statutory provisions for "waste" prevention extend to such an action, the Propose Rule would allow BLM to stifle exploration in frontier areas distant from gas gathering infrastructure. Although the Proposed Rule also allows BLM to suspend a non-producing lease while action on the APD is held in abeyance (authority BLM already has under 30 USC §209), the point is that BLM is creating a chicken and egg situation: gathering infrastructure will not be built in an area until there is a proven supply of gas to transport, and the existence of that gas cannot be shown until wells are drilled. In addition, §3179.10 seems to ignore Sec. 366 of the Energy Policy Act which requires BLM to issue the permit within 30 days after receipt of a complete APD "if the requirements under the National Environmental Policy Act of 1969 and other applicable law have been completed within such timeframe" or defer a decision and provide the applicant a notice that specifies any steps the applicant could take for the permit to be issued AND a list of actions that BLM needs to complete together with timelines and deadlines for completing such actions. In frontier areas, there will be nothing the applicant can do to make "gas capture capacity" available unless it is willing to bear the expense of installing electricity generation or gas liquidation facilities in advance of knowing whether the well will produce sufficient quantities of gas to power those facilities. A regulation that allows BLM to delay indefinitely the approval of an APD in areas where gathering infrastructure is not yet available could seriously diminish the value of leases covering lands in remote areas and work as a disincentive to test new geologic concepts.

B. Criteria for determining when flared gas is "waste"

Section 3179.4 is intended to clarify the definition of what constitutes "unavoidable loss" of gas from flaring by, among other things, "listing specific operations and sources that produce gas that BLM would deem 'unavoidably lost,' as long as the operator has not been negligent, has not violated laws, regulations, lease terms or orders, and has taken prudent and reasonable steps to avoid waste."[72] The list needs to be expanded, as explained below.

1. The definition of "unavoidably lost" should include gas gathering force majeure events, which disrupt gas take-away capacity, and should not be subject to the 24 hour duration limit applicable to emergencies. Venting and flaring during a force majeure event should also

[72] *Id.* at 6665.

not be royalty bearing (3179.5) and should be excluded from flare limit calculations (3179.6) and measurement requirements (3179.8).

Volumes flared as a result of a force majeure event are unavoidably lost under NTL-4A Section II.C.(2) ("'Unavoidably lost' production shall mean…(2) that oil or gas which is lost because of line failures, equipment malfunctions, blowouts, fires, or otherwise…"). During a force majeure event, a well may continue to sell at its full rate or at a reduced rate, depending on whether the gatherer is flaring gas at the pipeline outlet and depending on how much line pack volume (spare capacity) is available before the pipeline reaches maximum allowable operating pressure (MAOP).

Once connected to a gas sales pipeline, all flaring due to "compressor or other equipment failures, relief of abnormal system pressures, or other conditions which result in the unavoidable short-term venting or flaring of gas" is authorized under NTL 4A Section III.A as an "Emergency" without incurring a royalty obligation. Gas is frequently flared in North Dakota when the line capacity or compression capacity is reached because allowing those volumes to flow (such as by increasing the separator pressure), creates the potential to exceed pipeline MAOP and risk line failure.

In addition, the State of North Dakota flaring regulations provide exceptions to the flaring limits for flaring that result from force majeure events.[73] The North Dakota requirements have achieved the goal of reducing flaring in the state while still providing critical flexibility that allows for continued operations without penalties during a force majeure event.

Thus, the Proposed Rule is inconsistent with the existing flaring regulations in North Dakota and the BLM's own existing regulations under NTL-4A, both of which provide essential exceptions for force majeure events. Because a force majeure event is, by its very nature, unforeseen and beyond an operator's control, all flaring during a force majeure event should

[73] *See* North Dakota Industrial Commission, North Dakota Industrial Commission Order 24665 Policy/Guidance, , available at https://www.dmr.nd.gov/oilgas/GuidancePolicyNorthDakotaIndustrialCommissionorder24665.pdf, stating that "[t]he operator is allowed to remove from the total monthly volume calculation gas volumes flared from wells already drilled and completed on the date a force majeure event occurs if the event is properly documented in writing by the gas gathering company."

constitute "unavoidably lost" gas under the proposed rule, should not contribute to any volume limitation, and should not require metering. BLM could simplify the rule by simply considering any gas flared from a well that is connected to a pipeline as being unavoidably lost. Obviously, once an operator has connected a well to a pipeline, it has every incentive to maximize the revenue from that investment. Any disruptions are going to be the result of operational events beyond the operator's control, such as those related to capacity issues.

2. Consistent with NTL-4A, losses from "low-pressure production vessels" (such as heater treaters, which function as secondary separation), should be considered "unavoidably lost" (3179.4), should not be royalty bearing (3179.5), and should be excluded from flare limit calculations (3179.6) and measurement requirements (3179.8).

Low-pressure production vessels typically include secondary (tertiary, etc.) separation equipment, wherein gas is recovered at pressures below the gathering pipeline operating pressure and wherein the gas volume contribution is too low to reasonably make sales without significant operating and/or capital expense.

For example, traditional facility setups in the Bakken include a first stage two phase separator, which separates the majority of gas from the combined liquid stream. It is followed by a three phase heater treater, which separates water from oil as well as any gas remaining with the liquid stream that is recoverable at the equipment's specific operating conditions. The standard practice is to operate the inlet separator at or slightly above (to account for line loss pressure drop between the separator and sales meter) the MAOP of the gas sales line. Thus as long as the pipeline has not reached its MAOP, all separator gas will sell.

The treater typically operates at least 15 psig less than the separator to allow liquids to dump via pressure between the two vessels. The treater's maximum allowable working pressure is typically 75 psig, which is less than typical sales line MAOP in the Bakken. Because this vessel operates at a very low pressure, closer to 30-50 psig, treater gas cannot normally enter the sales line and any treater gas vented or flared from this low-pressure vessel should constitute an "unavoidable loss" consistent with NTL-4A Section II.C.(1) ("'Unavoidably Lost' production shall mean (1) those gas vapors which are released from storage tanks or other *low-pressure production vessels…*") (emphasis added). This exception in NTL-4A for low-pressure vessels reflects operational realities and must be included in the Rule. Note that the language of NTL-4A expressly provides a separate exemption for low pressure production vessels in addition to storage tanks. Per ASME Boiler & Pressure Vessel Code VIII, a "pressure vessel" is defined relative to a tank as operating above 15 psi, thus a Treater constitutes a "low-pressure production vessel."

Furthermore, to comply with NDIC Order #25417 (the "Oil Conditioning Order"), companies must operate treaters at or below 50 psig, which will ensure these treater gas volumes must go to flare rather than to sales based on typical gathering line pressures. Consequently, the proposed rule directly conflicts with existing North Dakota requirements, and it would be infeasible (if not impossible) to comply with both rules simultaneously.

Field measurements at a sample of sites across the Bakken where the separators and the treaters are equipped with allocation gas meters show that treater gas makes up approximately 3% or more of total, non-tank vapor gas on average for typical pressure conditions. Due to the relatively low volume of gas from the treater, it is infeasible, uneconomic and unnecessary to install pad compression or a vapor recovery unit to capture this low pressure gas. Again, NTL-4A reflects operational realities that the proposed rule fails to consider.

3. It is not feasible to add a redundant gathering system, especially with a dedicated gas contract in place. BLM has grossly underestimated the time, effort and cost to capture incremental volumes in a constrained system like the Bakken. The Rule must account for the economics specific to the well and region in question.

BLM's premise in the preamble, RIA, and Proposed Rule itself is that additional permanent infrastructure can be built to capture the incremental flare volumes where capacity is constrained or remote capture technology can be deployed to individual well sites where permanent infrastructure is undersized or infeasible. The RIA incorrectly asserts that in times of downturn and reduced activity due to low commodity prices, gathering companies can "catch up." However, the exact opposite is true. When commodity prices are low, it also impacts the gas gatherers, making additional capital investment difficult and less likely.

Under NTL 4A, BLM may approve venting or flaring of oil well gas without incurring a royalty obligation based on engineering, geologic, economic, and recoverable reserves information. A narrower set of standards for existing wells is specified in Section 3179.7(a)-(c) of the new rule. In connection with a recent appeal to the BLM State Director of a BLM North Dakota Field Office Decision Record regarding the Field Office's proposed plan for processing flaring sundry notices, the State Director issued a decision ("State Director Decision") concluding, among other things, that the costs and economics of gas capture must be considered in making an "avoidably lost" or "unavoidably lost" determination.[74] BLM must revise the "unavoidably lost" definition to include gas flared once connected to a gas pipeline. However, if such a definition change is not made, section 3179.7 should be simplified to expedite the approval process and modified to apply to both existing and new pads with gas pipeline connections.

Gas pipelines require long term planning and investment, including lengthy ROW and permitting processes, particularly on tribal land. Often the slowest permits are related to the BIA, USFS, and BLM jurisdictions, and the State Director Decision recognizes these ROW challenges and deems all flaring while a ROW is pending to constitute "unavoidable loss". In addition, the "North Dakota Industrial Commission Order 24665 Policy/Guidance" document issued by the NDIC expressly provides for temporary exemptions for ROW delays. The local BLM authority in the Bakken and the State both recognize that flexibility is required for ROW delays. This concept is absent from the Proposed Rule and needs to be included.

Midstream companies gather gas from many pads from many operators under dedications because production from multiple locations is necessary to invest in the infrastructure, especially with rapid decline rates such as in the Bakken. It would be difficult and uneconomic for any single operator to pay for a dedicated gas pipeline and processing system with a few wells that

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[74] *See* SDR No. 922-15-07 issued February 11, 2016 by Aden L. Seidlitz, Acting State Director, at 9, 10, 12.

quickly decline to low volumes. To support infrastructure investment, gas gatherers require commitments from producers to ensure gas will flow through their infrastructure. These commitments vary by agreement and market but almost universally limit alternate gathering options. Furthermore, most dedicated contractual obligations make it difficult to bring a long-term secondary gathering system to the same pad location. If such a secondary agreement were allowed, it would only be allowed on an interruptible basis and would only be used sporadically, thereby making a secondary system even more uneconomic and infeasible.

Gas gatherer economics (a full discussion of which is beyond the scope of these comments) are heavily dependent on capturing volumes because most gas gathering agreements charge per unit of gas transported across the system. Gas gathering systems rely on pad-specific infrastructure that typically consists of a pipeline and measurement equipment that connects the pad to a commingled system of lower pressure trunklines, compressors, and higher pressure discharge lines to efficiently move the gas from the pad to a treating and/or processing facility to make the gas and associated liquids (if any) marketable to the downstream markets. Early production in a well's life is critical for the gas gatherer to recoup the investment for the pad-specific infrastructure. Any operation mode (e.g. automatic shut-ins or waiting until infrastructure "catches up") that risks flattening the decline curve by capping production could be expected to jeopardize gas gatherer economics and further hinder infrastructure investment.

Building a separate gathering system for each operator would not only be economically prohibitive, but it would also be redundant and require multiple ROWs in the same area and across the same landowner property. Repeated ROW requests increase surface use and have led historically to landowners unreasonably or intentionally blocking easements and demanding exorbitant compensation from operators.[75] A redundant plant and the necessary compressor stations further lead to increased surface use.

Any backup gas gathering infrastructure must be completely redundant and would require a cost burden of approximately 10 times the market value of the recovered gas, assuming gas

[75] The North Dakota Industrial Commission recognizes the difficulty in obtaining rights-of-way and specifically allows temporary exemptions for right-of-way delays.

volumes available for redundant sales of approximately 20%, based on current Bakken flare percentages. Lessees cannot afford this undue burden.

4. BLM should consider flaring associated with pigging activities "unavoidably lost."

Due to the high liquid content of the gas in some areas, the gas gatherers must frequently pig their lines, sometimes multiple times in the same day, to manage liquid buildup. Pigging essentially involves launching a malleable or hard plug (called a pig) from an upstream location and allowing pressure to carry the pig to a receiver. The pig sweeps liquid forward and thus reduces liquid in the line. As the pig and liquid front sweep through the system, pressure increases upstream and can thus reduce sales volumes.

Pigging is generally not considered a force majeure event, but it can cause operational outages similar to a force majeure event. Furthermore, during pigging operations, it is undesirable to completely shut-in upstream wells as the drive mechanism for the pig will be lost and the likelihood of a stuck pig scenario will be increased, which would only exacerbate flaring or keep wells shut-in longer.

Flaring during pigging operations should be considered "unavoidable". Given the frequency of pigging, it is infeasible and unduly burdensome for the gatherer to document and provide notice of all pigging events. Therefore, proper gathering line operation and pigging further justify that all flaring from wells connected to pipeline constitutes "unavoidably lost" gas without necessity of BLM approval.

5. It is not a given that associated gas produced from a well will be of sufficient quality to be marketed, and in some instances the cost of processing gas to bring it to pipeline specification may exceed the value of the recovered product. We urge BLM to consider exempting gas based on the presence of CO_2, Oxygen, Nitrogen, H_2S, and other impurities.

C. Royalty rates for newly-issued competitive leases

1. The process for raising the royalty rate above 12.5%

In accordance with the MLA, the Propose Rule would authorize BLM to set the royalty rate on competitive leases issued after the effective date of the rule at not less than 12.5%. BLM states that it "does not currently anticipate increasing the base royalty rate for new competitively issued leases above 12.5 percent," and that "[b]efore making such a change, the BLM would announce the change prior to the effective date, and would provide for a public comment period."[76] It also lists some of the "relevant factors" that it would "potentially" take into account in any decision to raise the royalty rate. BLM requests comment on "the adequacy of the public process [it] outlined."

As was made clear in the numerous responses that BLM received in response to its Advanced Notice of Proposed Rulemaking on the subject of raising royalty rates,[77] any decision to do so would be highly significant to a wide variety of stakeholders, and should be informed by a wide variety of considerations. The public process for making such a decision should not therefore be based on BLM's non-binding statements in the preamble to the Proposed Rule; it should be set forth in the rule itself. Indeed, even if the public process were not set forth in the rule, a decision to raise the royalty rate would be a "rule" as defined by the Administrative Procedures Act,[78] and therefore could not be made except in compliance with the notice and comment requirements of that Act. Moreover, the Proposed Rule should state that royalty rates will not be raised on existing leases.

The Proposed Rule should identify the specific factors BLM shall consider in making a decision to raise the royalty rate in advance of any leases to which the increase rate would apply (including, at a minimum, the factors it identified in the preamble to the Rule), and should state that: 1) BLM will give public notice of its intent to raise the royalty rate at least one year in

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[76] 81 Fed. Reg. at 6660.

[77] Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments, 80 Fed. Reg. 22,148 (Apr. 21, 2015) (advance notice of proposed rulemaking).

[78] 5 U.S.C. § 551(4).

advance of doing so; 2) the notice will include a full explanation of BLM's reasons for believing that a royalty rate increase is needed; 3) the public will be given at least 90 days to comment on the notice; and 4) BLM will respond in writing to the comments it receives before issuing its decision.

Moreover, even though BLM states that it "does not currently anticipate increasing the base royalty rate for new competitively issued lease above 12.5%," it is important to remind BLM that increasing the royalty rate above 12.5% would almost certainly have negative impact on oil and gas production on federal lands. John Dunham & Associates, an economic consultancy, has modeled the impact on federal production under twenty-four scenarios involving varying degrees of change to royalty rates and rental rates on federal leases.[79] Net expected production was calculated at a base royalty rate of 12.5%, and potential increases to 14.75%, 16.75%, 17.75%, and 18.75% with corresponding rental rates of the current $1.50/$2.00 per acre, $2.00 per acre, $3.00 per acre, $4.00 per acre, and $5.00 per acre. Under every scenario, raising royalty rates and rental rates had a negative impact on federal oil and natural gas production. The net result of that lost production is a reduction in federal energy revenues of up to about $51 million.[80]

While federal royalty rates are presently lower than royalty rates in some states,[81] there are good reasons why royalties on federal leaseholds are lower. For federal leases to be attractive to operators compared to leases on state and private lands, the federal lease rate must account for the time and expense involved in obtaining the lease, complying with overlapping state and federal regulations, performing the requisite environmental review required under federal law, and the difficulty involved with accessing federal lands. Our members' experience reveals that the overall cost of developing leases on federal and Indian lands is consistently higher than for similar projects on state and fee lands. While it is reasonable for BLM to attempt to set royalty

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[79] Dunham & Associates' full report describing the modeling efforts and conclusions is attached as Exhibit A to these comments.
[80] *See* Ex. A at 1. It must be noted that the model used for this analysis only assesses development in thirteen western states: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Some states with meaningful activity on federal lands, particularly California and Alaska, are not included in the model. As a result, the model likely underestimates the value of lost revenue attributable to higher royalty rates and lease fees.
[81] *See id.* at 3, Table 2.

rates at values that maximize the federal government's return on federal leases, the marketplace sets a limit on how high rates can be before federal leases become an unattractive asset.

Higher royalty rates and associated lease fees impact federal oil and natural gas production in at least two ways: (i) higher costs make marginal projects uneconomical;[82] and (ii) higher costs increase the risk premium that oil and natural gas producers will require before bidding on leases.[83] The extent of the impact on production is likely to vary based on a host of geologic and economic factors. Under current production costs and economic conditions, for example, royalty rate changes may have little impact on projects focused on natural gas because commodity prices make new development uneconomic under any royalty scenario. In legacy oil fields, however, where many drilling permits are issued and the drilling of inexpensive vertical wells is common, the impact of increasing royalties and associated leasing fees is much more significant.

Nor are losses limited to lost royalty revenue. The oil and natural gas industry currently generates more than 173,000 direct jobs (not including additional secondary jobs) in the thirteen states the model analyzes. Depending on which of the twenty-four scenarios examined is ultimately adopted, as many as 1,330 direct jobs could be lost in these states alone. And because workers in the oil and natural gas sector tend to be highly compensated relative to workers in other economic sectors, job losses in oil and natural gas development disproportionately impact overall economic activity.[84]

Under the modeled scenarios, the loss of direct revenue to the federal government from oil and natural gas leasing resulting from a reduction in wells developed due to increased royalty rates and lease fees could be as much as $37 million annually. This represents meaningful losses

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[82] Higher costs also mean that projects that are not presently economic are even less likely to occur in the future because more significant economic change is necessary before those projects can become economic. At least one federal agency has concluded that the development of marginally economic projects is already deterred because of the federal government's "regressive fiscal regime." Irena Agalliu, U.S. Dep't. of the Interior, Bureau of Ocean Energy Management, Comparative Assessment of the Fed. Oil & Gas Fiscal System . 5 n.5 (2011), http://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Fair-Market-Value/CERA-Final-Report.aspx. Higher royalty rates and lease costs would further exacerbate this existing problem.

[83] One strategy that operators are likely to employ to achieve this risk premium is offering lower bonus bids when bidding on federal leases. *See* discussion *infra* Part II.C.

[84] Ex. A at 10-11.

to the federal government, but also to the states that receive fifty percent of all monies from oil and natural gas production on federal lands within a state's borders.[85] But losses are not limited to the revenues from wells that are not drilled. Federal, state and local governments also stand to lose business, property and personal tax revenue from companies and individuals in the oil and natural gas activity, as well as the benefits of economic activity associated with full employment in the oil and natural gas industry. Modeling results suggest that these losses could well exceed $13.8 million for the federal government alone.

2. Fluctuating royalty rates

Although it has not been formally proposed, BLM states that it is "considering a provision that would allow royalty rates on new competitively issued leases to vary after the first year, based on the lease holder's record of routine flaring of associated gas from the lease during the previous year."[86] The purpose of the provision, which BLM refers to as a "royalty adder provision," would be: "(1) To create an incentive for bidders to consider the availability of gas capture infrastructure and the proximity of gas processing facilities as attributes that add significant value to Federal oil development leases; and (2) To create an incentive for Federal lease holders to plan for gas capture prior to or in conjunction with the development of oil wells."[87] Such a provision would be both an abuse of the Secretary's discretion and inconsistent with the Rule, and should not be given any further consideration by BLM.

The MLA gives the Secretary the discretion to set the royalty rate for competitive leases, as long as the rate is not less than 12.5%. The Secretary is to use her discretion to set the rate at a level that will insure a fair return to the government for the use of public resources. It would be an abuse of that discretion for the Secretary to use her authority instead to promote her policy to reduce flaring.

The adder provision would also be inconsistent with the Proposed Rule. Under the Proposed Rule, BLM is telling operators of new leases that flaring done in compliance with the

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[85] *See* 30 U.S.C. § 191(a).
[86] Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. at 6660.
[87] *Id.*

1,800 Mcf/month flaring limit will not be considered a "waste" of gas, and will therefore not be subject to a royalty. Under the adder provision, however, BLM would be telling those same operators that unless they flare at a significantly lower rate, "the threshold flaring rate", they will have to pay additional royalty. BLM gives no adequate explanation for this disconnect; it justifies the adder provision solely in terms of its ability to incentivize lease holders to plan ahead for gas capture. But the flaring limit in the rule and the requirement that operators develop waste minimization plans were supposed to provide that incentive. It would be arbitrary to say that flaring in compliance with the rule's 1,800 Mcf/month limit is not a "waste" of gas, and to then turn around and say that compliance with anything less than the adder provision limit would be a "waste" of gas, and would subject operators to a royalty increase.

We endorse the comments submitted to OMB by the Council of Petroleum Accountants Societies on this subject. They demonstrate the impracticability of this provision from an accounting perspective.

D. State or Tribal Variances

As detailed in the preamble, states, tribes, and EPA all have programs that deal in one way or another with the venting and flaring issue. It is thus extremely important that the Proposed Rule contain a variance provision that is workable and that will give timely relief to operators from duplicative or conflicting requirements. We would prefer a general deferral to existing state and tribal programs, but the variance provision offers at least the possibility of eliminating overlapping and duplicative requirements as a means of reducing administrative costs and improving efficiencies. If BLM is unwilling to defer to existing State and tribal programs, the following changes should be made in section 3179.401. Also, a variance provision should be added to the section 3160 to allow for a State to request a variance from the waste minimization plans.

1. The section should state that the request for a variance automatically tolls any deadline for compliance with the federal requirement from which a variance is being sought. Failure to

provide such a provision will make the provision for a variance practically meaningless, as operators will be left in regulatory limbo.

2. The section should state that any request for a variance that is not approved by the BLM State Director within 60 days of its submission shall be deemed approved. This will insure that the variance provision does not become a bottleneck that leaves operators uncertain for indefinite periods of time about the requirements that will apply to them.

3. The provision states that BLM "reserves the right to rescind a variance or modify any condition of approval." This unfettered discretion which allows BLM to revoke a variance for any reasons or no reason at all is clearly unreasonable and should not be part of the Proposed Rule. It will put the plans and investments of operators at continual risk, as operators will always have to reckon with the possibility that BLM will arbitrarily revoke a variance on which they have based their operational and investment decisions.

4. The section should state that States and tribes may appeal any denial of a request for variance or any revocation or modification of a variance. Without the right to appeal BLM's decisions, there is no protection against a completely arbitrary denial or revocation of a variance. Indeed, without a right to appeal, and hold BLM accountable for its decisions, the right to request a variance is of little practical value.

Conclusion

In closing, we reiterate the tremendous progress that America's oil and natural gas industry has made, and will continue to make, in addressing issues associated with venting, flaring, and methane emissions. However, after a careful examination of the Proposed Rule, we have concluded that it is arbitrary and in excess of BLM's authority and should not be promulgated. If BLM nonetheless proceeds with the rule, it needs to be substantially re-written to make it workable for industry and BLM, consistent with the many recommendations that we have made above. At a minimum, BLM should suspend work on the Proposed Rule until it is clear how EPA will regulate air emissions from existing oil and gas sources. This would be consistent with BLM's policy of avoiding duplicative or conflicting federal mandates. In the meantime, we would request that BLM direct its resources toward the timely processing of ROW applications, as that would have a much greater impact upon the reduction of flaring than the Proposed Rule.

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APPENDIX A

MEMORANDUM

TO: Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance
FROM: Mike Stojsavljevich
DATE: April 12, 2016
RE: Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR 3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)

Executive Summary:

As per your request John Dunham and Associates (JDA) has reviewed *Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)*, which was produced by the Bureau of Land Management (BLM) in January 2016.[1]

This analysis of the proposed rules estimates the costs far exceeding the benefits. The proposed rules are estimated by the BLM give a high end cost of between $117 - $174 million (assuming either a 3 percent or 7 percent discount rate, Environmental Protection Agency (EPA) finalizing or not finalization of Subpart OOOOa, and various methane reduction assumptions).[2]

JDA estimates that the costs exceed $1.26 billion, while the benefits as estimated by the BLM are between $115 - $384 million (assuming either a 3 percent or 7 percent discount rate, EPA finalizing or not finalizing of Subpart OOOOa, and various methane reduction assumptions).[3] A more reasonable estimate of the benefits suggest that they are at best $90 million[4], hence the cost-benefit ratio of the proposed rules is nearly 14:1 cost to benefit.

The $1.26 billion cost of the proposed rule to the industry is best examined in three primary components. First, based on the costs of implementation outlined in the RIA prepared by the BLM, JDA estimates an economic impact on jobs, wages, and lost output of $997,199,000. Additionally, those economic losses create an additional loss of $114,112,000 in federal and state taxes. Finally, a conservative estimate suggests a total of $174 million in costs associated with implementing the rule.[5] This can be viewed as an annual incremental cost to the industry.[6]

Additionally, a reduction in oil well development from the proposed rules will leave 112.4 million barrels of developable oil in the ground.[7] This undeveloped oil is best viewed as oil that is shut-in due to the regulatory burden of implementing the proposed BLM rules.

Also, the BLM claims benefits of about $23 million in Federal royalties and 16.5 million metric tons of carbon dioxide equivalent emissions. This reasoning does not reflect the current state of the market. JDA estimates that the $23 million dollar figure presented by the BLM would drop to $3.68 million or possibly

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1 U.S. Bureau of Land Management, *Regulatory Impact Analysis for: Revisions to 43 CFR 3100(Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and gas Operations)*, at: www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.11216.File.dat/VF%20Regulatory%20Impact%20Analysis.pdf

2 Ibid., pages 6-8.

3 Ibid., pages 6-8.

4 Based on JDA estimates

5 Cost estimates rise to $319 million if all rules are implemented, EPA does not finalize Subpart OOOOa, and there are no methane offsets, which we detail below.

6 The economic impact of $1.26 billion is based on $997 million in economic impact, $114 million in lost taxes and $174 million in costs to the industry, which is our low end estimate based on BLM's RIA. JDA's internal cost estimates rise to $319 million and could increase the total economic impact to $1.43 billion.

7 Based on internal JDA estimates

considerably less, even approaching $0 when examining the current pricing environment and understanding the super-cyclical nature of the current oil and gas industry where inventory builds may create a situation where there is no additional demand for oil or gas

Background

This analysis also examines the claims and procedures of the regulatory impacts done by the Bureau of Land Management (BLM) and their proposed rulemaking, which would update 43 CFR Part 3100 (Onshore Oil and Gas Leasing) and 43 CFR Part 3160 (Onshore Oil and Gas Operations) and propose new regulations 43 CFR Chapter II, Subpart 3178 (Royalty-Free Use of Lease Production) and Subpart 3179 (Waste Prevention and Resource Conservation). The proposed Subparts 3178 and 3179 would update and replace the BLM's current policy document Notice to Lessees-4A (or "NTL-4A").

The BLM rule claims to have five specific goals:

1) Modify the requirements that limit the venting and flaring of produced natural gas. The proposed rule would prohibit venting of gas except in certain circumstances, and would limit gas flaring during normal production operations from development oil wells to 7,200 Mcf/month (on average, per well, across all of the producing wells on a lease) for the first year of the rule's implementation, 3,600 Mcf/month/well for the second year of the rule's implementation, and 1,800 Mcf/month/well thereafter. Gas flared from a well that is connected to infrastructure would be royalty-bearing except in certain narrow circumstances, such as emergencies.

2) Limit losses of gas through venting and leaks by placing requirements on other activities and equipment, including well drilling, completions and workovers, production testing, pneumatic controllers and pumps, storage tanks, liquids unloading, and leak detection and repair (LDAR). As a practical matter, many of the proposed requirements would impact only existing equipment or facilities that are not regulated by the EPA's existing New Source Performance Standards (NSPS) Subpart OOOO (nor by the EPA's recently proposed Subpart OOOOa, if that rule is finalized).

3) Conform the BLM's royalty rate provisions for competitive oil and gas leases to the corresponding statutory text, which prescribes a rate "not less than" 12.5 percent.

4) Require the operator to submit additional information to the BLM with its Application for Permit to Drill (APD) for a new oil well. Specifically, the operator must submit its plan to minimize the waste of natural gas from the planned well to the degree reasonably possible.

5) Clarify the parameters for an operator to use production on lease without paying royalties on that production. The changes would ensure that the royalty free use of production applies only to uses on the lease, unit, or CA. The changes would not prohibit the operator from using the production off the lease, unit, or CA, but those uses would incur royalties.

Conduct of a Regulatory Impact Analysis:

As part of the rulemaking process, all Federal regulatory agencies are required to conduct a Regulatory Impact Analysis (RIA). While these analyses are designed to determine if a proposed regulation will have a reasonable effect on the environment while not costing society substantial resources, they are also designed to determine if there are other alternative measures that the regulatory agency should take rather than proposing new rules. Unfortunately, the Bureau of Land Management (BLM), which developed this RIA has built a case for this regulatory endeavor by using outdated data sources and this flawed data and methodology have led to flawed conclusions.

The BLM performed an impact analysis for individual rulemakings under the Act's authority. The analysis must contain an analysis of each of the following impacts:

- The costs of compliance,
- Any potential inflationary or recessionary effects,
- Effects on competition with respect to small businesses,
- Effects on consumer costs, and
- Effects on energy use.[8]

This is not a true regulatory impact analysis but rather a general accounting based on outdated data sources of the direct costs of the proposed regulation. More importantly, two long-standing Presidential Executive Orders require all agencies, including the BLM, to conduct an analysis of the benefits and costs of a proposed significant regulatory action, including a comparison of the benefits and costs of alternative regulatory approaches.[9] Executive Order 12866 requires that all regulatory actions be reviewed by the Office of Management and Budget (OMB) and gave the Office broad powers to review and request revisions to all regulatory proposals.

This same Executive Order requires that an agency, including BLM, "Shall ... propose or adopt a regulation only upon reasoned determination that the benefits of the intended regulation justify (emphasis added) its costs."[10]

The Requirements of an RIA:

According to the Office of Management and Budget (OMB), there are 16 key elements that every Regulatory Impact Analysis (RIA) needs to address.[11] The OMB even provides agencies with a detailed primer on how to conduct an RIA in accordance with its guidelines and the underlying Executive Orders.[12] Additional requirements from the various laws governing RIAs such as the Unfunded Mandates Reform Act and the Regulatory Flexibility Act also need to be met by the BLM.

The OMB suggests that each agency include are:

1. A reasonably detailed description of the need for the regulatory action;
2. An explanation of how the proposed regulatory action will meet that need;
3. An appropriate baseline assessment of how the world would look in the absence of the proposed action;
4. An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action;
5. An explanation of why the planned regulatory action is preferable to the potential alternatives;
6. An uncertainty analysis;
7. A description and discussion of the distributive impacts of the potential alternatives;
8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action;
9. A clear and transparent table presenting anticipated benefits and costs.

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8 *Economic impact assessment*, United States Code, Title 42, Chapter 85, Subchapter III, Sec. 7617, at: http://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapIII-sec7617.htm

9 Federal Register, Vol. 58, No. 190, *Executive Order 12866 of September 30, 1993*, Monday, October 4, 1993, at: https://www.archives.gov/federal-register/executive-orders/pdf/12866.pdf

10 Ibid.

11 Office of Management and Budget, *Agency Checklist: Regulatory Impact Analysis*, www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/RIA_Checklist.pdf.

12 Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, at: www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf.

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner;
11. Provide the data, sources and methods used in the RIA to the public via the internet;
12. Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible;
13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible;
14. Explain and support how the benefits of the intended regulation justify its costs;
15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach;
16. Use appropriate discount rates for benefits and costs expected to occur in the future.

In addition to these 16 items, a proper RIA must examine a number of additional impacts including international effects and the effects on small businesses.

Very few RIAs ever fully follow the OMB guidelines, even though they represent best practices for this sort of analysis. This is definitely the case with the RIA performed by the BLM staff for this proposed rule. Not only does the RIA fail to perform 10 of the 16 checklist items, the analysis presented is biased, and uses many flawed assumptions.

Critique of the Analysis Prepared by the BLM:

This critique examines each of the items suggested by the OMB and outlines particular issues with how the BLM performed this particular study.

1. <u>A reasonably detailed description of the need for the regulatory action</u>: **The RIA does document a need for regulatory action on the part of the BLM.** According to the RIA, a large amount of natural gas is being wasted through venting and flaring at oil and gas production sites on Federal and Indian lands, despite the fact that this gas could be economically captured and delivered to the market. The RIA cites a 2008 GAO estimate that about 128 billion cubic feet of natural gas was either vented or flared from Federal leases, of which 50 billion cubic feet was economically recoverable.[13] The BLM claims that this recoverable volume represents about $23 million in lost Federal royalties and 16.5 million metric tons of carbon monoxide equivalent emissions.

   This reasoning does not reflect the current state of the market. First, the average natural gas price for the full year 2008 was $8.85 per MCF. This compares to a spot price in March of 2016 of just $1.40.[14] This is an 84 percent drop in the price of natural gas since the 2008 time frame which the GAO uses in its report. Based on the 84 percent reduction in the price of natural gas, the $23 million dollar figure presented by the BLM would drop to $3.68 million.

   Further, the RIA states that in 2013, about 98 Bcf of natural gas was vented and flared from Federal and Indian leases. At a $4/Mcf price of natural gas, this volume has a sales value of $392 million and a royalty value of $49 million. Of the 98 Bcf, the BLM estimates that 22 Bcf was vented and 76 Bcf was flared. The agency also estimates that 44 Bcf of the flared gas came from the Federal and Indian mineral estates with 32 Bcf coming from the estates of other mineral owners.[15]

   Therefore, the BLM in its analysis neglects to evaluate the current market landscape in terms of prices and industry dynamics which indicate rising inventory levels of natural gas and the potential for a

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13 Op. cit. Regulatory Impact Analysis, page 2.

14 Braziel, E. Russell, The Race To Liquids, Oil & Gas Finance Journal, August 1, 2010, on-line at: www.ogfj.com/articles/print/volume-7/issue-8/features/the-race_to_liquids.html; CNBC.com for March 14, 2016 natural gas price.

15 Op. cit. Regulatory Impact Analysis, page 3.

supply glut. Natural gas prices have been as low as $1.40 per Mcf in March of 2016 or 65 percent lower than the RIA estimate, implying a sales value not of $392 million and a royalty of $49 million but a number closer to $137.2 million in sales and $17.15 million in royalties.

Adding in the economic marginal impact of the additional volume in a market landscape with heavy inventories it could easily be assumed that all of that volume may be much lower and could have a marginal value approaching $0.

2. <u>An explanation of how the proposed regulatory action will meet that need</u>:
The BLM, with this proposed regulatory action explicitly seeks to enhance waste prevention and resource conservation. Explicitly stated and often discussed is methane reduction. The ability to measure methane reduction and tie it to conservation is not readily achievable. Air quality and pollution control regulations address "negative externalities" which represent the cost of pollution which is borne by society rather than producers. The RIA presupposes that methane emissions impose costs on society, such as negative climate, health, and welfare impacts that are not reflected in the market price of the petroleum produced. This can indicate that there is a need to promulgate regulations that minimize these costs. However, many scholars, including for example, Nobel Lauriat Ronald Coase, have suggested that there are other ways for society to alleviate the consequences of negative externalities. In fact, correcting an externality may impose externalities on different groups of people. This is why the OMB requires that all RIA submissions include an alternatives analysis.

   Without a proper baseline to measure the effects of the regulations, it is impossible to determine if they will meet the need of reducing any economic costs associated with "methane reduction."

3. <u>An appropriate baseline assessment of how the world would look in the absence of the proposed action</u>: **BLM does not provide a "null analysis" in its RIA.** There are no estimates of how this additional volume of natural gas that is brought to market would impact the current price of natural gas.

4. <u>An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action</u>: **Only a very general alternatives analysis is presented in the RIA.** Royalty rate alternatives were discussed in general terms with no analysis performed. In fact, only one actual alternative was presented and it related to the flaring of gas. This alternative simply reduced the amount of gas flared to 20 million cubic feet. This is not, as suggested by OMB, a range of potentially effective and reasonably feasible regulatory alternatives including deferral to state or local regulation, the use of economic incentives to encourage the desired behavior, market-oriented approaches, different compliance dates or different requirements depending on firm size. The whole reason for an RIA is to examine alternatives and weigh the costs and benefit of different approaches to achieving the same goal. The BLM's RIA completely fails on this important aspect. Additionally, this arbitrary number does not examine a significant issue, the appropriate amount of venting or flaring to achieve maximum safety.

5. <u>An explanation of why the planned regulatory action is preferable to the potential alternatives</u>: **One alternative was presented, but there is no explanation of why the BLM's preferred regulatory action is preferable. Additionally, very uncertain and potentially unrealistic natural gas price estimates were used.**

6. <u>An uncertainty analysis</u>: The BLM presents a sizable degree of uncertainty in just about every listed benefit that it claims the proposed rule would generate. In fact, the Agency suggests that it cannot even determine what the price of natural gas will be in the future. The BLM states that it "believes" that there are economical and cost-effective measures that operators could take to minimize waste

based on advancements in technology, yet they cite no advancements that would be relevant to minimizing waste.

7. A description and discussion of the distributive impacts of the potential alternatives: While the RIA contains a section labeled *Distributional Effects,* it only examines the impact of the regulations across two categories: Small vs. large businesses and across potential pollution sources. OMB states that the analysis of the distributional effects should examine the impact of the proposed action across the population and economy divided up by a range of demographic and economic categories.[16] **This is not an analysis of the distributional impacts of the proposed rule as laid out in OMB Circular A-4.**

   The need for a distributional analysis is particularly acute in that these regulations are geared toward a single industry – oil and natural gas production. Other methane producing industries are not included. Higher costs in one industry reduce investment and activity in that sector and as such, encourage investment and activity in another. If capital were to move from the production of oil and natural gas to the production of say beef cattle, then the amount of methane produced may actually increase. If this has an effect on "climate change," the effect may be greater. More importantly, since oil and natural gas can be produced in many different countries the regulations may simply transfer activity from the United States to Russia, Mexico, Iraq or Nigeria. This can not only impact the American economy but could also lead to increased methane production.

   Most importantly, the RIA completely fails to examine how the proposed regulations impact different segments of society and different areas of the country, a requirement specifically outlined in OMB Circular A-4.

8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action: **This is included in the analysis**.

9. A clear and transparent table presenting anticipated benefits and costs: **The analysis presents the calculated benefits and costs in a clear table.**

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner: As with many RIA documents, the agency involved is using the analysis to justify its proposed regulatory action. First the best data are not used. Specifically, data for natural gas prices at the peak of their historical range (2008) are utilized. Additionally, company profitability estimates come a select list of10-K financial filings from 2012-2014 for a sample of companies that are assumed to represent the industry. Survey data is also analyzed second-hand and not provided in raw form to the public.[17] What is even more astounding is that nowhere in the RIA is the volatility and economic hardship of the industry in 2015/2016 even stated. Much of this data is

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16 Specifically Circular A-4 States: *Those who bear the costs of a regulation and those who enjoy its benefits often are not the same people. The term "distributional effect" refers to the impact of a regulatory action across the population and economy, divided up in various ways (e.g., income groups, race, sex, industrial sector, geography). Benefits and costs of a regulation may also be distributed unevenly over time, perhaps spanning several generations. Distributional effects may arise through "transfer payments" that stem from a regulatory action as well. For example, the revenue collected through a fee, surcharge in excess of the cost of services provided, or tax is a transfer payment.*

Your regulatory analysis should provide a separate description of distributional effects (i.e., how both benefits and costs are distributed among sub-populations of particular concern) so that decision makers can properly consider them along with the effects on economic efficiency. See: Office of Management and Budget, *Circular A-4*, September 17, 2003, at: www.whitehouse.gov/omb/circulars_a004_a-4#f.

17 This specific survey data was analyzed by Carbon Limit (a consulting firm).

now out of date and not indicative of either the pricing environment for oil or gas, nor are the company financial filings reflective of the current financial state of the industry.

BLM bases its assumptions on the benefits related to reduced methane emissions, on past Environmental Protection Agency (EPA) analysis and on pronouncements from a Federal interagency working group. The RIA states that BLM has estimated "the quantity of methane reduction using emissions factors and reductions data made available by EPA."[18] BLM also states that it estimates the social cost of methane using the values presented by Marten et al (2014), EPA's analysis of Subpart OOOOa and EPA's New Source Standards for Municipal Solid Waste Landfills. Further, BLM states that they estimated social cost of carbon dioxide on the Interagency Working Group on Social Cost of Carbon.[19]

This is not a complete analysis and is clearly biased because the BLM must first have established that those methane emissions that might be prevented by this rule actually impact "climate change" in some way. OMB requires agencies to establish a baseline which represents the agency's best assessment of what the world would be like absent the action. This baseline needs to focus on benefits and costs that accrue to citizens and residents of the United States. According to OMB, where the agency chooses to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.[20] Nowhere in the document does the BLM document any baseline cost of climate change on the economy of the United States. As such it is impossible to determine if the benefits anticipated by the BLM even accrue to the American economy. It is also impossible to determine if they have any meaningful effect on the overall factor being measured, that is the perceived economic cost of "climate change."
Without a proper baseline to measure the effects of the regulations, it is impossible to determine if they will meet the need of reducing any economic costs associated with "climate change."

Additionally, the entire benefits calculation done by BLM is based on an EPA analysis which in itself is based on an extremely fragile examination of the "climate change" benefits. The values are not derived from any models presented in the study, but rather from a book published in 2000 which purports to measure the cost of supposed "climate change" due to carbon dioxide (CO2) emissions.[21]

The EPA analysis which BLM incorporates, states that although several researchers that had directly estimated the social cost of non-CO2 GHG emissions, there was considerable variation among these published estimates both in terms of the models and assumptions. Furthermore, none of the other published estimates of the social cost of non-CO2 GHG were consistent with the CO2 estimates developed by an interagency working group (IWG) that included other executive branch agencies which used three integrated assessment models (IAMs) to develop the CO2 estimates used in this RIA. These CO2 estimates were first released in February 2010 and updated in 2013. In other words, the analysis uses assumptions unilaterally decided on by the Federal Government to measure a social cost of CO2 emissions.

Also, BLM goes on to suggest that a paper published by Marten (2014) provides the first set of published methane estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the CO2 estimates. What the agency fails to mention is that the authors of this paper are all staff of the EPA. In fact, the Marten article does not even generate its own estimates of the potential economic benefits of reduced methane emissions, but rather calculates estimates of

18 Op. cit. Regulatory Impact Analysis, page 32.

19 Ibid

20 Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, at: www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf.

21 Nordhaus, William D. and Joseph Boyer, Warming the world : economic models of global warming, Massachusetts Institute of Technology, 2000. Available on line at: http://eml.berkeley.edu/~saez/course131/Warm-World00.pdf

climate impacts of methane relative to CO_2. In doing this the authors come up with a range of values of from $349 and $1,183 per ton, a 239 percent difference. In short, the figures used to calculate the purported benefits are based on an EPA sponsored paper that examines data on CO_2 and makes a number of assumptive jumps to methane impacts. Even this paper admits to an extreme level of variation in its modeled figures.

This particular failing of the RIA is critical. In fact, this entire RIA presents little in the way of actual analysis. Rather it ties together a number of policy statements, and uses policy documents to support them. The RIA first determines that the production of oil and gas leads to the emissions of methane. From this point, the entire calculation of benefits is based on findings that are determined by the BLM to be self-evident, but which are not supported by facts. First, all of the literature cited about potential "climate change" costs of methane actually discusses CO_2. The BLM bases their analysis on EPA, which then uses a paper produced by its own staff, which describes internal procedures used by EPA to translate methane into CO_2 equivalents. While this paper may appear in a "peer-reviewed" journal, the paper and the journal were about internal bureaucratic processes, not chemistry.[22] In other words, it is saying "trust us" we know how this works.

BLM then multiplies these derived CO_2 equivalents by a cost factor that comes not from independent research, but rather from an internal Administration working group. As such, these cost figures are not determined in an unbiased and independent manner, but by the agency that is promulgating the regulations. In fact, the entire process hinges on the unsupported assumption that the minor levels of methane emissions identified as coming from oil and natural gas developments have a negative effect on the economy. The entire analysis can be summarized by the simple statement, "Methane emissions have a negative effect on the economy because we (the BLM) say so." **This suggests that the RIA might not have been conducted in a non-biased manner.**

11. <u>Provide the data, sources and methods used in the RIA to the public via the internet</u>: While the report is extensively cited, much of the source material is not readily available or is not available without some additional cost. **The BLM does not provide a library of the materials or data used in its analysis that is available to the public without additional cost.**

12. <u>Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible</u>: **The RIA does not demonstrate a way to monetize the proposed benefits, but only quantifies a purported economic benefit from the regulatory action which is between $255 and $384 million annually depending upon various assumptions**.[23] There are some major analytical leaps to monetize these benefits, and the actual figures are all based on 2008 commodity prices, material lifted from 10-K reports from 2012-2014, and survey data from 2012 – 2014, which was analyzed second hand by a firm called Carbon Limits which focuses on climate change mitigation.[24]

    Also for example, the largest line item, leak detection and repair (LDAR) compromises $88-$119 million dollars of the $255 to $384 million benefit (roughly one third). In regards to this, the BLM states that "the impacts of an LDAR requirement are uncertain."

    Also, flaring requirement estimates show a potential $7 to $16 million cost (not benefit).

[22] Peer review is not a euphemism for fact. Many journals publish papers on topics that the reviewers are not familiar with. Papers may be published because the present an interesting data set, a new process, or a formal analysis. In this case, the paper was published because it described an internal EPA process, not because it presented the results from a chemical experiment.

[23] Op. cit. Regulatory Impact Analysis, page 6.

[24] Op. cit. Regulatory Impact Analysis, page 222.

The old data, broad ranging estimates and potential negative values significantly lower the actual benefits. Utilizing current data and modern analytical techniques would bring the total benefit $90 million.

13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible: According to the RIA, the costs to implement the proposed regulations could reach $174 million per year.[25] This is well below the actual cost of implementing the rules as proposed. In fact, JDA estimates that the total cost of implementation of the proposed rules to the industry is a staggering $1.26 billion dollars on an annual basis.

The cost components are in eight categories: Flaring Requirements, Well Completion, Pneumatic Controllers, Pneumatic Pumps, Liquids Unloading, Storage Tanks, LDAR, Administrative burden.

These numbers are derived primarily from certain key assumptions contained in the RIA and cited by the BLM. These are:

- A total of 37,000 – 38,000 wells are potentially impacted by LDAR inspections
- Flaring limits affect no more than the RIA's stated 1,111 well sites
- Flare metering rules affect no more than 635 sites
- Well drilling, completions and maintenance proposed rules will affect no more than 1,575 wells
- Liquids unloading proposed rules affect more than 1,550 well
- There are no additional exploration leasing and permitting costs

Table 1 presents the eight components and the costs per well.

Table 1
Costs by Component[26]

Affected Component	Cost per well	Number of affected wells
Flaring (total including limits and metering)	$73,583	1,111
Well Completion	$7,619	1575
Pneumatic Controllers	$384	15,600
Pneumatic Pumps	$307.69	8775
Liquids Unloading	$3,871	1550
Storage Tanks	$20,625	3,200
LDAR	$3,736.00	38,000
Administrative burden	$67.34	38,000
Total	$110,193	

The BLM's high end estimate would be the lowest reasonable cost estimate. However, the number of wells serviced per year could be much higher than 38,000 and potentially double the amounts listed above, which could drive these costs much higher. If the given range is $117 - $174 million, doubling of the wells service count would increase the cost range to $234 - $348 million.

14. Explain and support how the benefits of the intended regulation justify its costs:

[25] Op. cit. Regulatory Impact Analysis, page 81.
[26] Assumes that there are no additional remediation costs as no exploration or new wells are being produced.

Any benefits at all rely on two criteria, the recovery and sale of natural gas and natural gas liquids and the assumed benefits of reduced methane emissions.

From a macro level the recovery and sale of natural gas and gas liquids is a highly questionable endeavor in these market conditions, The RIA states that the BLM is "unable to account for existing LDAR programs, and that these benefits likely overstate the true benefit of the rule."[27] The LDAR benefit is the largest benefit component of the rule.

Further, market dynamics continue to be highly volatile as commodities specifically natural gas are currently perceived to be super-cyclical with global demand weakening inventory build may take years to work themselves out. During this period of time adding additional volume to the market could very well not be feasible.

Additionally, in regards to methane benefits, the science is unclear as to whether a social cost benefit exists for reduced methane. As discussed in point 10 above, BLM bases their methane benefit on EPA analysis, which rests on a potentially unstable academic foundation. Without further analysis and robust debate, the BLM cannot assume that there is any benefit at all to reduced methane emissions.

15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach: **A new estimate based on 2016 data, specifically prices should be conducted to reflect accurate net benefits.**

16. Use appropriate discount rates for benefits and costs expected to occur in the future: The BLM discounts its cost estimates using discount rates of three percent and seven percent; however, these are applied individually as separate analyses, and not used appropriately to discount effects on private capital (7 percent) and effects on private consumption (3 percent) as suggested by the OMB. **The discounting performed in the RIA is, therefore, not properly conducted.**

The Economic Impact of the Proposed Rules:

Table 2
Reduction in Oil Well Development Due to Proposed Rules

State	Estimated BLM Wells	Estimated Lost Wells	Well Loss Percent	Potential Lost Barrels of Oil
Arizona	2	-	0.00%	-
Colorado	6,878	(934)	-13.58%	(4,664,186)
Montana	2,819	(115)	-4.07%	(855,323)
Nebraska	31	(31)	-100.00%	(24,849)
Nevada	118	-	0.00%	-
New Mexico	30,490	(1,330)	-4.36%	(12,209,466)
North Dakota	1,874	(1,335)	-71.23%	(87,290,963)
South Dakota	87	(8)	-9.73%	(2,290)
Utah	8,909	(416)	-4.67%	(3,589,667)
Wyoming	31,647	(537)	-1.70%	(3,726,608)
Total	82,855	(4,707)	-5.68%	(112,363,352)

27 Op. cit. Regulatory Impact Analysis, page 130.

The costs imposed by the proposed rules would significantly impact the economic dynamics of the oil and gas industry. Based on JDA's dynamic model of the oil and natural gas industry, it is likely that as many as 4,700 fewer oil wells would be undertaken as a result of the rules.

Table 3
Economic Impact of Proposed Rules

State	Direct Jobs	Total Jobs	Direct Wages	Total Wages	Direct Output	Total Output
Colorado	(313)	(461)	$ (31,354,725)	$ (40,564,096)	$ (111,825,404)	$ (135,583,684)
Montana	(22)	(35)	$ (1,891,244)	$ (2,442,224)	$ (6,906,425)	$ (8,671,377)
Nebraska	(4)	(4)	$ (203,759)	$ (218,971)	$ (823,259)	$ (871,976)
New Mexico	(284)	(432)	$ (22,738,385)	$ (29,643,023)	$ (88,125,869)	$ (109,183,574)
North Dakota	(936)	(1,777)	$ (101,895,616)	$ (144,462,783)	$ (253,428,069)	$ (377,768,038)
South Dakota	(1)	(2)	$ (51,516)	$ (92,917)	$ (228,566)	$ (395,277)
Utah	(103)	(202)	$ (8,035,385)	$ (12,813,377)	$ (27,294,340)	$ (42,191,094)
Wyoming	(118)	(144)	$ (11,446,685)	$ (12,736,722)	$ (50,313,519)	$ (54,363,414)
Entire United States	(1,780)	(3,845)	$ (177,617,315)	$ (308,296,515)	$ (538,945,451)	$ (977,199,362)

By reducing new oil and natural gas development, and potentially reducing continuing operation of marginal fields, the proposed regulations could have significant impacts on employment in regions where there are developments on BLM lands. This is particularly important considering that the industry is already suffering substantial job losses due to the current low market prices for petroleum products. Based on models developed by John Dunham and Associates for Western Energy Alliance, these proposed rules could result in as many as 1,780 lost jobs for people directly involved with oil and natural gas development and production, and as many as 3,850 jobs once all supplier and induced impacts are taken into account.[28] These are real people with real jobs, currently receiving as much as $308.3 million in wages and benefits. All told, the economy could lose as much as $977.2 million in overall economic output annually.

This lost economic activity will have a significant and direct fiscal effect, that in and of itself would be larger than any potential benefits that might result from the proposed rules. It is estimated that the annual fiscal effect of the proposed rules would be as high as $114.1 million, of which $65.6 million represents lost federal taxes. The remaining $48.5 million in lost revenues would be seen by states and local governments that depend in part of revenues from the development of oil and natural gas fields.

Table 4
Fiscal Impact of Proposed Rules

State	Federal Taxes	State Taxes	Total Taxes
North Dakota	$ (26,243,000)	$ (11,087,000)	$ (37,330,000)
Colorado	$ (7,591,000)	$ (4,964,000)	$ (12,554,000)
New Mexico	$ (5,548,000)	$ (4,771,000)	$ (10,319,000)
Wyoming	$ (3,162,000)	$ (2,272,000)	$ (5,434,000)
Utah	$ (2,130,000)	$ (2,026,000)	$ (4,155,000)
Montana	$ (464,000)	$ (337,000)	$ (800,000)
Nebraska	$ (7,000)	$ (21,000)	$ (28,000)
South Dakota	$ (8,000)	$ (7,000)	$ (15,000)
United States	$ (65,601,000)	$ (48,511,000)	$ (114,112,000)

Conclusions:

28 Based on John Dunham and Associates, *Western Oil & Natural Gas Employs America*, prepared for Western Energy Alliance, 2014, at: www.westernenergyalliance.org/employsamerica

A careful analysis of the facts laid out in the RIA leads to one clear conclusion, and that is that the costs of $1.26 billion annually to the economy far outweigh even the highest end BLM benefit estimate of $384 million.[29] This is based on a price for natural gas of $2.00/Mcf.[30]

This year, natural gas prices have dropped to as low as $1.57 per million BTU and $1.40 Mcf according to the EIA and media sources cited above. Discounting the idea that a reduction in potential methane emissions would have any benefit on the environment that could be monetized[31], a more reasonable calculation of the potential benefit of the proposed rule would be $90 million.

With a cost of $1.26 billion and a potential benefit of just $90 million, this rule does not produce a net social benefit.

In addition to not completing the RIA in accordance with published OMB guidelines, the BLM included a number of assumptions that were on their face either false, or should not have been used as part of this type of analysis. The most glaring problem is the BLM's inflated commodity price estimate which underlies the entire economic benefit claimed. BLM fails to acknowledge that at current commodity prices the oil and natural gas industry is in its biggest bear market in 30 years, and implementing this extremely expensive rule would have a very adverse impact in such a depressed market, and will lead to lost development on federal lands. Additionally, BLM fails to address the fact that the rule in its imposition of a no venting standard would lead to unsafe drilling, completion and storage practices, which is not examined in any real depth in the RIA.

The BLM's failure to conduct a comprehensive alternative analysis was clearly in violation of the OMB guidelines. An alternatives analysis may have shown that the proposals could actually lead to increased and significant economic costs to the oil and gas industry.

Given such flawed analysis and self-reported doubts by the BLM in the RIA, it is very possible that a new analysis would find significantly varied results.

29 Op. cit. Regulatory Impact Analysis, pages 6-8.

30 Op. cit. Regulatory Impact Analysis, page 42.

31 The benefits as laid out by the BLM are also speculative at best as they rely on passage of EPA Subpart OOOOa and rely on certain assumptions that methane gas reductions have a social cost benefit.

APPENDIX C

LETTER • OPEN ACCESS

Designing better methane mitigation policies: the challenge of distributed small sources in the natural gas sector

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LETTER

Designing better methane mitigation policies: the challenge of distributed small sources in the natural gas sector

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Supplementary material for this article is available online

Abstract

Methane—a short-lived and potent greenhouse gas—presents a unique challenge: it is emitted from a large number of highly distributed and diffuse sources. In this regard, the United States' Environmental Protection Agency (EPA) has recommended periodic leak detection and repair surveys at oil and gas facilities using optical gas imaging technology. This regulation requires an operator to fix all detected leaks within a set time period. Whether such 'find-all-fix-all' policies are effective depends on significant uncertainties in the character of emissions. In this work, we systematically analyze the effect of facility-related and mitigation-related uncertainties on regulation effectiveness. Drawing from multiple publicly-available datasets, we find that: (1) highly-skewed leak-size distributions strongly influence emissions reduction potential; (2) variations in emissions estimates across facilities leads to large variability in mitigation effectiveness; (3) emissions reductions from optical gas imaging-based leak detection programs can range from 15% to over 70%; and (4) while implementation costs are uniformly lower than EPA estimates, benefits from saved gas are highly variable. Combining empirical evidence with model results, we propose four policy options for effective methane mitigation: performance-oriented targets for accelerated emission reductions, flexible policy mechanisms to account for regional variation, technology-agnostic regulations to encourage adoption of the most cost-effective measures, and coordination with other greenhouse gas mitigation policies to reduce unintended spillover effects.

1. Introduction

Global natural gas use is very likely to increase in coming decades [1]. Replacing coal with natural gas significantly reduces almost all air quality impacts, solving a profound challenge facing the rapidly growing megacities of Asia [2]. And in developed economies, natural gas could become more, not less, important because gas turbines readily support flexible power grids with large fractions of renewable power. These trends are strengthened by recent breakthroughs in unconventional gas production that promise decades of gas supply at affordable prices. However, increased use of natural gas has heightened climate concerns because leaked natural gas, which is comprised mainly of methane, is a potent greenhouse gas (GHG) [3, 4].

Globally, methane accounts for 16% of all GHGs in the atmosphere, second only to carbon dioxide [5]. A third of all methane emissions in the United States (US) come from the hydrocarbon (HC) sector (natural gas and petroleum systems) [6]. Recognizing this, the US aims to reduce HC sector methane emissions in 2025 to 40%–45% below 2012 levels [7]. More recently, Canada, US and Mexico agreed to jointly reduce methane emissions [8]. Concurrently, several important developments have brought public attention to the methane leakage issue. Recent incidents—like the Aliso Canyon blowout in California, [9] and deadly explosions in distribution systems in Taiwan [10] and Argentina [11] have increased public scrutiny of gas infrastructure.

However, reducing methane emissions from our HC system is a challenge. There are approximately 1 M oil and gas wells in the US, thousands of processing and handling facilities, and millions of km of transmission and distribution piping below our factories and cities [4]. Each well can contain hundreds of possible points of leakage, and facilities can contain thousands of components. Thus, mitigating methane from the HC sector requires a completely different approach than regulations based on monitoring a small number of large point sources (e.g. power plant CO_2 emissions).

In this context, the US EPA recently finalized updates to the 2012 New Source Performance Standards, henceforth called the *final rule*, to regulate methane emissions from the HC sector [12]. The *final rule* expects to mitigate about 0.46 million metric tons (Mt) of methane in 2025, and result in climate benefits worth 690 M$, at a cost of 530 M$. By comparison, total methane emissions from the oil and gas industry stood at 9.8 Mt (−16%/34%) in 2014 [6]. The *final rule* targets emissions across the natural gas supply chain, including production, processing, gathering and boosting, and transmission and storage sectors. It specifies equipment replacement and operational modifications, as well as periodic leak detection and repair (LDAR) surveys. EPA recommends the use of optical gas imaging (OGI) technology in LDAR surveys, as an alternative to the older standard 'Method-21' (M21), which relied on point-source concentration measurements. OGI technology relies on images and videos of methane leaks that are made visible using infrared imaging cameras. In the *final rule*, OGI-based LDAR is estimated to mitigate 60% or 80% of emissions for semiannual or quarterly surveys, respectively [12]. However, a recent analysis of OGI technologies showed that OGI performance varies significantly with environmental conditions, operator practices, and characteristics of the facility [13]. Therefore, further study is needed to understand whether OGI-based LDAR will result in expected emissions reductions.

Technology effectiveness aside, recent studies of methane emissions provide more cause for concern. For example, many studies have found 'super-emitting' leaks, which are few in number but can cause most of the emissions from a facility. There is also significant regional variation [4] in emissions. To illustrate, a recent study [14] found gathering and processing leakage rates varied from less than 0.2% to about 1% in different regions. Similarly, the Bakken region of North Dakota was found to be leaking up to 6% of produced gas [15, 16] while similar measurements made in Texas [17] show much lower emissions rates. In the face of this diversity, an important question arises: Will the new policies help achieve methane mitigation targets, and if not, are there effective alternative frameworks?

In this work, we analyze the effectiveness of the *final rule* and develop a framework to design improved policies for methane emissions reduction. Our findings are as follows:

1. variation in the baseline emissions estimate between facilities leads to large variability in mitigation effectiveness
2. highly heterogeneous leak-sizes found in various empirical surveys strongly affect emissions reduction potential;
3. emissions reductions from OGI-based LDAR programs depend on a variety of facility-related and mitigation-related factors and can range from 15% to over 70%;
4. while implementation costs are 27% lower than EPA estimates, mitigation benefits can vary from one-third to three times EPA estimates;
5. a number of policy options will help reduce uncertainty, while providing significant flexibility to allow mitigation informed by local conditions.

To support these conclusions below, we first describe our simulation framework. Then we explore uncertainty arising from various facility-related, and mitigation-related factors. We discuss the implications of this uncertainty on the costs and benefits of regulation. Lastly, we develop recommendations that form a framework to effectively mitigate emissions from distributed sources.

2. Methods

General approach: We use an open-source model, the Fugitive Emissions Abatement Simulation Toolkit or FEAST [18], that simulates methane leakage from natural gas facilities at the component level with high time resolution. FEAST uses information about model-plant parameters, generates leaks from an empirical leak-population and applies OGI-based leak detection technology to evaluate mitigation effectiveness. Once 'detected' by the technology module, the leaks are removed from the field. New leaks are added over time in a stochastic manner. All simulations are conducted for a total time of 8 years, with capital costs distributed evenly at 7% interest, as per EPA calculations. At the end of every simulation, the per-site time-averaged leak rate is calculated and compared to the time-averaged no-LDAR leak rate to estimate the additional emission reductions due to policy intervention (see supplementary note 2.1 at stacks.iop.org/ERL/12/044023/mmedia).

OGI technology model: The OGI technology module in this work is modeled after FLIR's GasFind IR-320 camera used for methane leak detection. Images of plumes, as seen by the camera, are simulated using first-principles modeling of the infrared molecular absorption spectrum of methane and

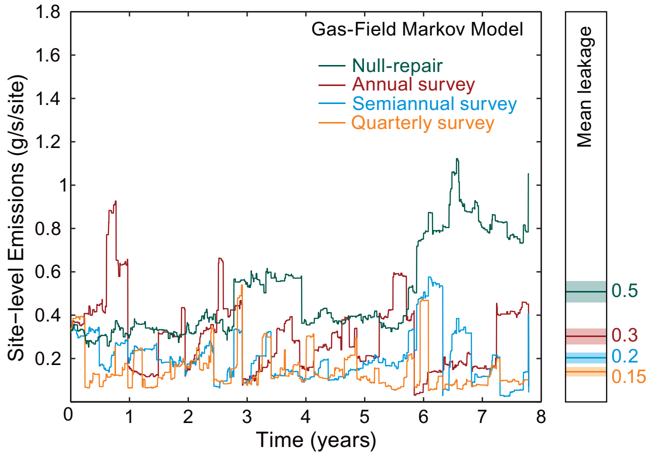

Figure 1. Time-series of a single simulation of OGI-based LDAR programs at gas well-site facility. Four different scenarios are shown: the null-repair scenario (green) shows a facility where leaks are repaired periodically via voluntary mitigation efforts, such that the mean leakage corresponds to publicly-available measured data; and OGI-based LDAR implementation at annual (red), semiannual (blue), and quarterly (orange) survey schedule. The shaded area around mean leakage values (right side bar) represents standard error. Following EPA regulations, all detected leaks are immediately removed from the gas-field.

quantifying the influence of background thermal radiation [13]. Modeling of methane leaks is undertaken using a Gaussian plume dispersion model. We have previously shown that the effectiveness of using an IR camera for leak detection is strongly dependent on environmental conditions, operator practices, underlying leak-size distribution, and gas composition. We use this OGI technology module to evaluate emissions mitigation based on periodic LDAR surveys at natural gas well sites. To realistically model field conditions, we assume that the methane leaks are in thermal equilibrium with the surroundings at a temperature of 300 K, and the composite background emissivity is 0.5. More information on camera properties and other module parameters can be found in online supplementary note 2.2.

Data: Parameters for model plants of all facility-types are derived from the technical support documentation provided as part of EPA's *final rule* [19]. Some analysis also make use of EPA baseline emissions calculations for appropriate comparisons to our model. The population of ≈6000 leaks and the leak-size distribution are taken from various publicly available empirical datasets of natural gas systems in the production [20–22], gathering and boosting [23], and transmission and storage sectors [24]. Economic and policy parameters like capital costs, survey costs, repair and resurvey costs, and gas prices have been modeled after EPA's methodology [19] (also see supplementary note 3).

3. Simulation with an open-source model

FEAST simulates the evolution of leaks at gas facilities, using data from a variety of publicly available data-sets (see online supplementary note 3) to estimate methane emissions and model the effectiveness of LDAR programs. It uses components counts, site characteristics, economic data, and LDAR designs from EPA's analysis [19] (see online supplementary note 4). FEAST also contains an OGI-technology simulation module which simulates the physics of infrared methane imaging cameras [13] (see online supplementary note 2). In FEAST, leaks evolve via a two-state Markov process: each component is in a 'leaking' or 'non-leaking' state with a finite probability of changing state at any given time. The probability that a leak will be found and fixed depends on the LDAR technology employed as well as properties unique to the gas field. Each simulation is run for a period of 8 years with one day time steps.

FEAST contains a 'null-repair' scenario where the total leak rate reaches steady state in the absence of any LDAR program or policy intervention. This is due to a null repair rate that finds and fixes leaks from the system. The null repair rate represents periodic repairs from operators undertaken through voluntary leak mitigation programs. FEAST can then compare this null-repair scenario results to various LDAR implementations. FEAST outputs results showing the time-series of leakage from a particular realization (see figure 1). In the 'null-repair' scenario with no-LDAR performed, the leakage averages 0.5 g s^{-1}/site, with variation due to the random leak generation process. Figure 1 shows the leakage from the same modeled facility under three different LDAR programs: annual, semiannual, and quarterly OGI surveys. We see that the mean leakage in these cases reduces (0.3 to 0.15 g s^{-1}/site) as survey frequency increases.

4. Testing the mitigation policy

Uncertainties in mitigation effectiveness of the *final rule* can be studied systematically under two broad classes: facility-related uncertainty and mitigation-related uncertainty. Facility-related uncertainties refer to effects

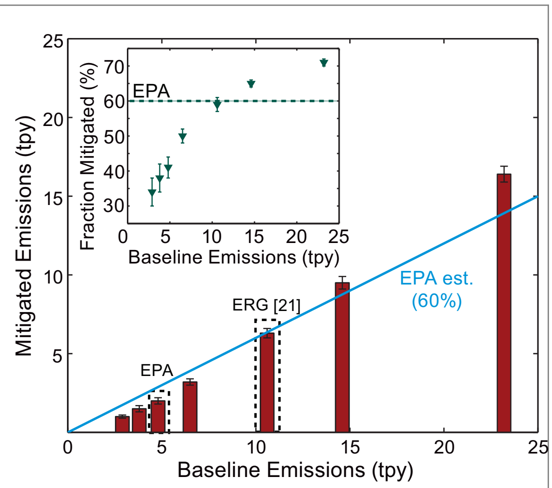

Figure 2. Effect of baseline emissions on the performance of OGI-based leak detection. Effect of baseline emission calculations on the total amount of methane mitigated at a gas well-site production facility. The blue line represents the 60% mitigation level as expected in the *final rule*. (inset) Fractional mitigation as a function of baseline emissions, with the EPA assumption of 60% shown as a dashed green line.

not related to the mitigation program: regional variation in leakage, facility-dependent emissions distributions, estimates of baseline emissions, or chemical composition of the gas resource. Mitigation-related uncertainties are driven by variation in detection technologies and their application in LDAR programs. These uncertainties include minimum detection limits of OGI-based cameras, the influence of environmental conditions during the survey, and sensitivity of OGI to non-methane emissions. We first examine facility-related uncertainties.

4.1. Baseline emissions: effects of voluntary mitigation

An important driver of mitigation effectiveness is the rate of baseline emissions. Baseline emissions are the steady-state leaks in a facility prior to the implementation of policy-mandated LDAR programs. They vary significantly across similar facilities because of regional differences, operator practices, and processing requirements. EPA calculates baseline emissions by multiplying emissions factors for each component at a given facility with the typical number of components at a 'model plant' [19]. Five different model plants with corresponding baseline emissions are specified in the *final rule*: gas well-sites (GW), oil well-sites (OW), gathering and boosting (G & B) stations, transmission (T), and storage (S). The assumed steady-state baseline emissions in a facility will strongly affect the benefits from an LDAR mandate. A higher baseline emissions rate would be associated with higher emission-reduction potential and larger potential cost recovery from saved gas.

To quantify the effect of variation in baseline emissions, we simulate a semiannual OGI-based LDAR survey at a GW site. The leak population and their size-distributions are derived from a survey of ≈400 GW sites in Texas [20] (see online supplementary note 3). Different baseline emissions are modeled by varying the repair rate of the null repair process—a high null-repair rate represents significant voluntary emissions reductions and diligent repair, leading to lower baseline emissions (online supplementary note 5.1). Figure 2 shows the average emissions mitigated in metric tonnes per year (tpy) under different baseline emissions scenarios. The diagonal blue line represents 60% emissions mitigation as expected by the EPA for a semiannual survey. Emissions mitigation range from about 1.1 tpy for a baseline leak rate of 3 tpy to over 16 tpy at a baseline leak rate of ≈ 23 tpy. This corresponds to fractional emission reductions ranging from 37% to 71% (see inset of figure 4). OGI-based reduction fractions vary because of two related processes. While the null repair rate is assumed to repair leaks independent of its size, the OGI-based process removes only the largest leaks. Thus, using OGI-based leak detection technology in a facility with baseline emissions lower than ≈ 10 tpy tends to result in mitigation percentages that are smaller than the expected 60%.

4.2. Effect of skewed leak-size distribution

An even more important facility-related uncertainty is the variability in leak size distribution. Various studies have demonstrated that leak size distributions are highly heterogeneous, with a small fraction of 'super-emitters' contributing a large fraction of total emissions [25]. Because the minimum detection limit of a leak-detection technology is fixed, differing leak-size distributions will significantly affect mitigation even if the total volume of leakage remains constant. Figure 3(*a*) shows normalized cumulative share plots of five artificial leak-size distributions, A–E (see online supplementary note 5.2). The emissions contribution from the largest 10% of emitters varies from 30% in distribution A (least skewed) to 70% in distribution E (most skewed). All facilities exhibit a total emissions volume of ≈10 tpy. We now plot the fractional mitigation resulting from a semiannual OGI survey (figure 3(*b*)). We see that in Facility A, OGI only mitigates 16% of the emissions; while Facility E, with the most-skewed leak population, mitigation exceeds 50%. Clearly, estimates of expected emissions reductions are highly dependent on facility leak size distributions.

We next use six publicly-available component-level leak data-sets from five studies on production [20–22], gathering and boosting [23], transmission [24], and storage [24] facilities (figure 3(*c*)). We simulate OGI based monitoring at the EPA-recommended survey schedule for each facility. In order to directly compare simulation results with EPA-expected emissions reductions, we force each facility to have baseline emission values that corresponds to EPA estimates for that facility type (see online supplementary table S3 for details).

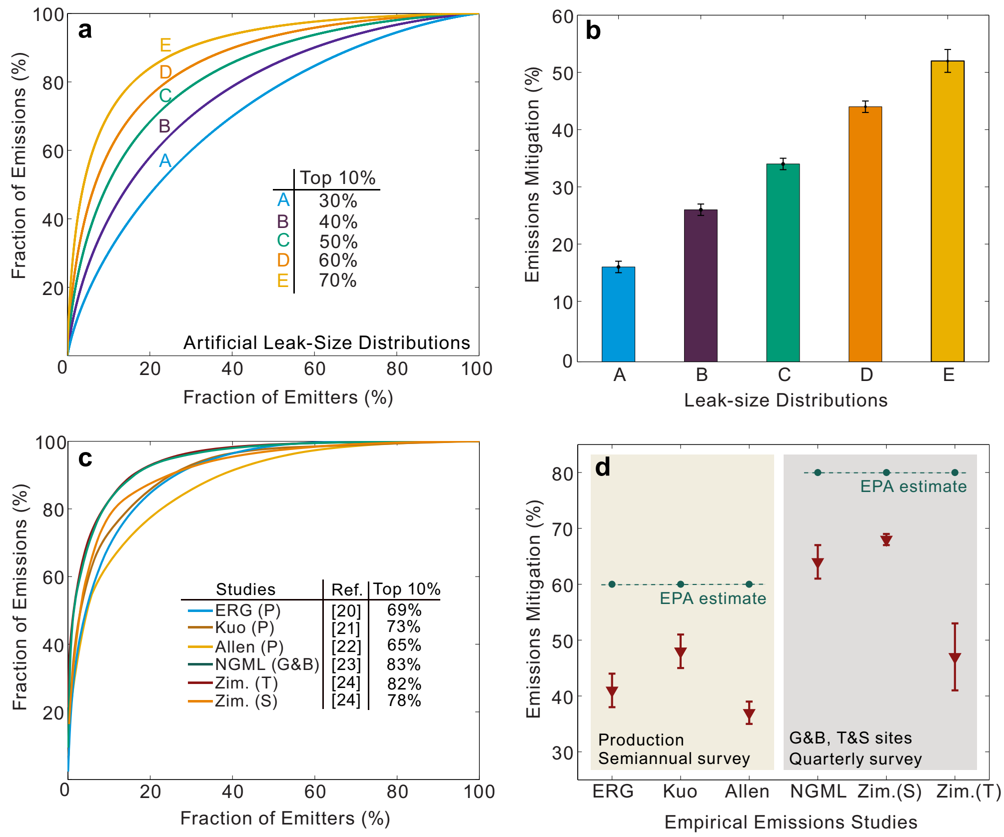

Figure 3. (*a*) Normalized cumulative leak-size distribution for a set of five artificial populations with a baseline emission of about 10 tpy. (*b*) Effect of artificial leak-size distributions shown in (*a*) on fractional emissions mitigation at typical gas well-site production facilities. (*c*) Normalized cumulative leak-size distribution showing the fraction of emitters (*x*-axis) and the fraction of emissions (*y*-axis) for five publicly available empirical studies—three in the production sector (ERG [20], Kuo [21], Allen [22]), and one each in the gathering and boosting (NGML [23]), transmission (Zim.(T) [24]), and storage (Zim.(S) [24]) sectors. (*d*) Emissions mitigation at each of the facilities shown in (*c*) on an OGI-based leak detection survey simulated at the *final rule* recommended frequency. EPA-estimated mitigation values are shown in dashed green lines.

Figure 3(*d*) shows the fractional mitigation for OGI-based leak detection surveys using these datasets with typical OGI survey conditions (see online supplementary note 2.2, but briefly: imaging distance of 5 m and ambient temperature of 300 K). In all cases, we find that simulated emissions mitigation falls short of the EPA-expected 60% (semiannual survey) or 80% (quarterly survey) mitigation levels (green dashed lines).

To explore the production sector cases in more detail: a semiannual LDAR survey only reduces emissions by 37%, 41%, and 48% in the facilities modeled using the Allen [22], ERG [20], and Kuo [21] distributions, respectively. These differences arise despite baseline emissions in all three analyses set equal to EPA-estimated 5 tpy. Variations observed, then, can be attributed to different leak-size distributions in the three studies considered. This shows that assuming a uniform baseline emissions volume for all facilities in a given industry segment is *not sufficient* to drive uniform mitigation benefits. The *final rule* does not model the direct relationship between leak volumes, leak size distributions, and leak detection effectiveness.

4.3. The role of technology and mitigation program

In addition to facility-related uncertainties explored above, mitigation-related uncertainties are also important. Here, we explore the impacts of four mitigation-related uncertainties: imaging distance, detection criteria, ambient temperature, and ambient wind conditions. In all cases, we model GW sites, using a large dataset of leaks generated from peer-reviewed studies (see online supplementary note 5.3 for details).

Figure 4(*a*) shows emissions reductions as a function of imaging distance and survey frequency. Reductions can vary from about 15% (imaging annually at 50 m) to as high as 70% (imaging quarterly at 5 m). Compared to EPA's estimate of 60% reduction from a semiannual survey schedule, we see large variability in mitigation potential. Our results indicate that a 60% emissions reduction from semi-annual surveys is possible only when leaks are imaged at a distance less than 5 m from the leak source. Importantly, the *final rule* does not specify an acceptable survey distance. Furthermore, over 50% of total achievable mitigation at any imaging distance is realized from an annual survey schedule, leading to less variability with changing survey interval than might be imagined. Note that the *final rule* focuses on specifying the time interval of LDAR surveys, but does not specify a more impactful parameter, the survey distance.

Another mitigation-related uncertainty is the detection sensitivity. In OGI-based LDAR, detection

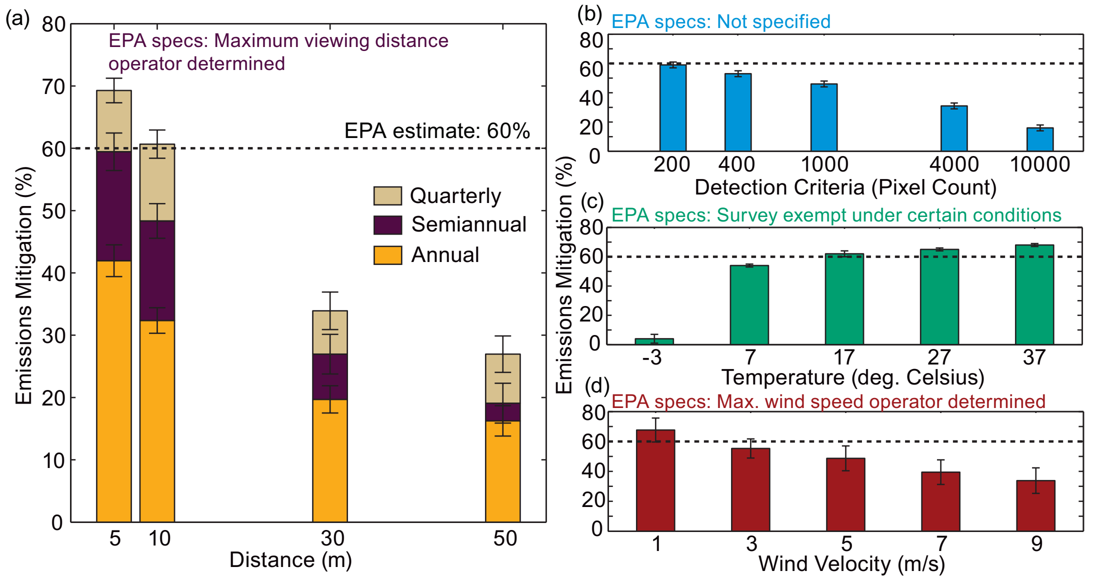

Figure 4. Effect of mitigation-related factors on the performance of OGI-based leak detection. Emissions mitigation at gas well-site production facilities as a function of, (*a*) imaging distance at three different survey schedules: annual (orange bars), semiannual (purple bars), and quarterly (beige bars), (*b*) detection criteria (pixel counts) of the OGI instrument, (*c*) ambient temperature—the temperature of the leak plume is assumed to be 2 K above the ambient temperature, and (*d*) wind velocity. Each sub-figure also notes EPA specifications as mentioned in the *final rule*.

depends on the visual acuity and experience of the operator. We model this factor by varying the minimum number of pixels affected in order for a plume to be detected. Figure 4(*b*), shows that emissions mitigation drops from ≈60% at a detection criterion of 200 pixels to 16% at a detection criterion of 10 000 pixels. In all simulations, a pixel 'registers' the plume if the signal-to-noise ratio (SNR) of the pixel is greater than or equal to 1. Specifying a higher SNR to reduce the occurrence of false positives will also reduce the detection effectiveness [13].

Environmental factors also affect OGI. The effects of temperature and wind velocity are shown in figures 4(*c*) and (*d*), respectively. Mitigation effectiveness abruptly drops near and below 270 K. This abrupt reduction indicates the temperature at which the temperature-emissivity contrast between the plume and its surroundings fall below the SNR of the camera modeled here. Any infrared imaging based detection system should account for significant reduction in detection effectiveness at low temperatures [13]. Wind velocity affects the dispersion of the plume in the atmosphere. Low wind-speeds are preferable to ensure that the plume body remains concentrated and therefore registers a high SNR on camera pixels. This is shown quantitatively in figure 5(*d*) where emissions mitigation reduced from 68% at calm atmospheric conditions with 1 m s^{-1} winds, to about 34% at winds of about 9 m s^{-1}.

5. Fixed costs, variable benefits

The costs of mitigation associated with the *final rule* can be decomposed into three categories: (1) one-time costs to develop compliance plans and other capital expenditures, (2) annual recurring costs associated with conducting LDAR surveys, and (3) costs of the repair and resurvey process. Because of the way the *final rule* is designed, the implementation costs do not vary considerably between similar facilities. On the other hand, the benefits from the expected sale of mitigated gas ('recovery credits'), are highly variable. Here, we analyze these costs and benefits at a GW site on a semiannual OGI-based LDAR schedule. A comparison of economic parameters between our model and that of EPA is summarized in table S6 (see supplementary note 4.5).

Figure 5 shows the implementation costs (red) and recovery credits (blue) at a site as a function of above-explored uncertainties. Two important results include: (1) implementation costs are fairly constant in both our model and EPA estimates, but costs in our model are 27% lower than EPA estimates; and (2) recovery credits vary significantly with mitigation-related and facility-related uncertainties explored above.

For semiannual LDAR monitoring, EPA estimates the implementation cost for all gas well-site production facilities to be \$2285/site (figure 5, red dashed line). By comparison, we estimate a cost of about \$1670 on average, a reduction of 27% from EPA estimates (figure 5, red triangles). The one-time costs and the annual recurring costs of OGI-based LDAR surveys are identical in both models. The difference arises because EPA has higher repair and resurvey costs compared to our model. This occurs because the EPA likely over-estimates the number of leaks found through an OGI-based LDAR survey, as discussed below. It should be noted that both models assume repair and resurvey costs are based on the number of leaks detected rather than the leak size—a reasonable assumption given that studies have shown no

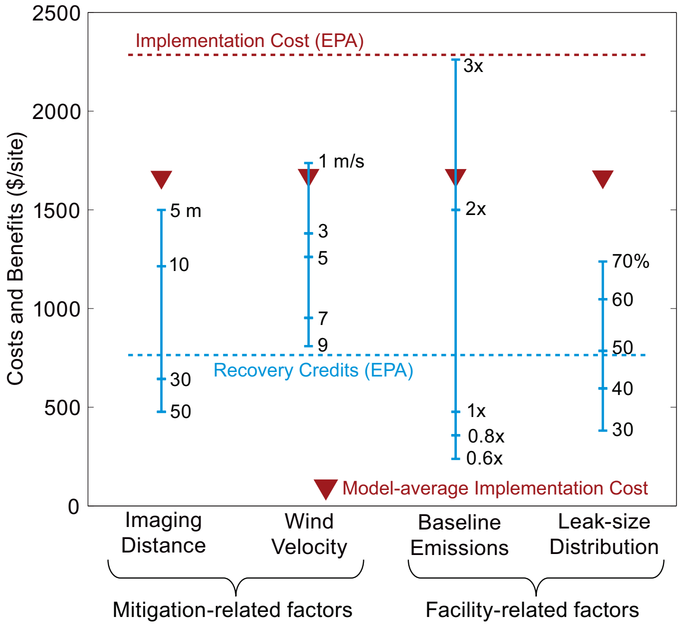

Figure 5. Implementation costs and recovery credits for a semiannual OGI-based LDAR survey at gas well-site facilities. EPA-estimated implementation cost (red-dashed line) is about 27% higher than our model-estimate averages (red triangles). Recovery credits (blue vertical lines) obtained from the sale of captured gas varies significantly based on both mitigation-related and facility-related factors. The tick marks on the recovery credits correspond to various values of the parameters—imaging distance is in m, wind velocity in m s^{-1}, baseline emissions as factors of EPA estimates, and leak-size distribution as the emissions contribution from the largest 10% of emitters. EPA estimate is shown as a dashed blue line.

correlation between repair costs and leak size [23, 26] (also see online supplementary note S5.4).

In estimating repair and resurvey costs, EPA assumes that 1.18% of all components are found leaking using OGI technology [19]. However, this number is inferred from prior measurements of valves in petroleum refineries using an M21 device at the 10 000 ppm screening level [27]. M21 relies on a local concentration measurement (i.e. device returns a ppm CH_4 reading) and concentrations above a screening threshold (i.e. 10 000 ppm) are considered leaking. However, this M21 leak definition cannot be directly applied to natural gas well-sites on an OGI monitoring schedule because of significant differences in detection thresholds. For example, one study which surveyed and quantified thousands of leaks at production sites using both M21 and OGI [20] showed that only 0.175% of components were found leaking using OGI, while 1.07% were found leaking with M21. An earlier EPA study found 2.2% of components leaking with a M21 threshold screening value of 10 000 ppm [23, p. iii], while a recent study using OGI found 0.28% of components leaking [21]. Thus, available evidence suggests that the number of components found to be leaking will be an order of magnitude lower using OGI (0.1%−0.3%) rather than M21 (1%−2%). This difference translates to significantly lower repair and resurvey costs, and hence, lower LDAR implementation costs. In our model the total implementation costs are dominated by the cost of conducting semiannual LDAR surveys: about 80% of GW site costs are from surveys. This results in a case where implementation costs are fairly constant, and independent of mitigation effectiveness.

However, the recovery credits from sale of captured gas vary significantly from EPA's estimates of $764/site. Here, we consider four different factors that affects the amount of emissions mitigated—imaging distance, wind velocity, baseline emissions, and leak size distribution. As imaging distance varies from 5–50 m, the recovery credits decrease from $1499/site to $214/site, respectively. This exemplifies an issue with the *final rule*—by varying an operator-controlled parameter such as imaging distance, the policy benefits vary widely. Similar dynamics are also at play with variations in wind velocity and other parameters. We also consider cases where baseline emissions range from 0.6–3 times the EPA estimate. For facilities with baseline emissions lower than the EPA estimate, the recovery credits available from a semiannual survey are lower than $500/site, covering less than a third of the implementation cost. On the other hand, facilities with high baseline emissions can accrue recovery credits that are higher than the implementation cost, resulting in a highly desirable net-negative cost of emissions control (see online supplementary note 6). Similarly, by varying leak-size distributions, we see that recovery credits vary from $381/site to about $1200/site with more heavy-tailed distribution. This indicates that 'super-emitters' greatly enhance the economics of OGI because the technology favors detection of the largest leaks.

6. Lessons for future mitigation policies

Combining our analysis with other recent findings, we propose improvements to methane mitigation regulation. First, an outcome-oriented policy with targets and an appropriate incentive structure will accelerate emissions mitigation. Second, a mechanism that accounts for regional variability can be more cost-effective. Third, technological flexibility can reduce costs and increase mitigation potential. And fourth, coordination with other emissions mitigation policies like the Clean Power Plan (CPP) [28] will be crucial to prevent unintended emissions spill-over effects. These four recommendations are discussed in further detail below.

Performance oriented targets for accelerated emissions reduction: First, performance based leakage targets based on either a mass-based (absolute emissions cap) or a rate-based (fraction of system throughput) will reduce the variability in mitigation effectiveness. This is because mitigation benefits can vary considerably based on technology, facility characteristics, and individual operator practices. At the same time, LDAR costs are directly proportional to the number of surveys. As we have seen, a poor survey implementation may result in highly sub-optimal emissions reduction. Such a standard perversely penalizes responsible operators with already low baseline emissions by forcing them to implement an LDAR program with minimal benefits. Also, the *final rule* only mandates that the behavior of LDAR is to be performed at some frequency. Such designs raise the possibility of not achieving mitigation goals if operators work to 'check the box' of the regulation requirements at lowest cost. A regulation that instead sets emission targets would allow operators to develop the most cost-effective means to achieve the target. Obviously, such targets would need to be enforced with periodic audits by regulatory agencies.

An outcome-oriented policy objective could have incentive structures that reward emissions mitigation that exceeds targets, while simultaneously penalizing non-compliance. This 'carrot-and-stick' approach can mitigate emissions at a rate faster than what conventional periodic LDAR surveys would allow. To illustrate, 'sticks' can take the form of fines or fees based on actual emission levels and a social cost of methane [29]; 'carrots' can include a system that rewards better-than-required performance (e.g. revenue recycling from fines or preferential permitting for excellent operators). Such target-based approaches would give operators the flexibility to choose mitigation technologies that are uniquely suited for their operations, improving cost-effectiveness.

Flexible policy mechanisms to account for regional variation: National emissions estimates, while important for accounting purposes, should not determine policy for all regions. There is growing evidence from a number of studies that methane emissions vary significantly based on basin characteristics and type of operation. For example, in a study of 114 gathering facilities across eight states, loss rates ranged from a low of about 0.2% to approximately 1% [14]. Measurements at production sites also show very different leak size distribution characteristics—the top 5% of emitters account for about 50% of total emissions in Barnett shale region [20], but over 90% in the Marcellus shale region [30]. Such differences in emission profiles will require different mitigation strategies. In this regard, states like Colorado have provided a template for effective regulation—in addition to LDAR programs at production and compressor facilities, Colorado instituted specific emissions management systems for storage tanks, where 'super-emitters' were more likely to occur. Estimates of expected emissions reductions should be tailored to reflect regional differences, and consequently, should also dictate the stringency and targets for mitigation programs.

Technology-agnostic regulations to improve cost-effectiveness: It would seem logical to specifically target and repair as quickly as possible the small number of super-emitters, resulting in large marginal abatement benefits. In this regard, OGI technology is ideally suited due to its ease in finding large leaks. However, as we saw in figure 4, the performance of this technology is sensitive to environmental conditions and 'detection' relies on the subjective judgment of the operator. Moreover, a semi-annual LDAR schedule could mean that large leaks go un-noticed for up to 6 months. When looking for super-emitters, continuous-monitoring technologies can trade-off sensitivity for lower cost, paving the way for real-time leak detection and mitigation. In addition to numerous technology start-ups, the Department of Energy's MONITOR program [31] is dedicated to developing cost-effective leak detection systems. However, it is unclear if and when such systems will be available on the market. Nevertheless, many other start-up companies promise to conduct leak detection surveys cost-effectively, with the main issue being the difficulty of demonstrating equivalence to EPA approved technologies. Policies should acknowledge future availability of newer and potentially cheaper technologies for leak detection and design regulations that allow for technological flexibility. Indeed, a mass or rate-based mitigation goal, as discussed previously, can be technology-agnostic, resulting in the flexibility that operators and states can use to great advantage, as long as mitigation targets are met and compliance is verified. Such technology-agnostic policies can have the dual advantage of giving operators choice in designing mitigation programs, while ensuring that a pre-determined methane mitigation goal is achieved in a cost-effective manner. As a spillover effect, such policies can establish a robust market for new technologies.

Coordination with other GHG mitigation policies to reduce unintended spillover effects: Finally, we stress the importance of coordinating a methane mitigation policy into the broader context of reducing GHG emissions from different sectors of the economy. The CPP, relies to a large extent on switching high-emitting coal-based power plants with low-emitting natural gas plants. Such fuel-switching, coupled with the shale-gas boom, can significantly increase natural gas production, along with associated methane leakage. Studies have shown that increased methane leakage in the natural gas sector can potentially erode the benefits of the Clean Power Plan [32]. Policy coordination is essential to avoid unintended negative spill-over effects in GHG emissions.

Aside from an emissions perspective, there is also evidence that mitigating all GHGs simultaneously as opposed to focusing on just carbon dioxide will be more cost-effective. Modeling results [33, 34] show that costs are 20%–50% higher when carbon pricing is applied only to carbon dioxide rather than all GHGs, for the same cap on atmospheric CO_2-equivalent concentrations. These results suggest that there might be low-cost options to mitigate non-CO_2 GHGs, in addition to policies that target CO_2 emissions.

While the four policy options discussed here are not cumulative, one can recognize significant co-benefits in implementing these regulations simultaneously. Furthermore, we argue that lessons on effective methane mitigation as described here are widely applicable. Recent work by Kirschke *et al* [35] indicates that emissions from fossil fuels dominate the regional methane budgets in Europe, Middle-East and Russia. Despite global differences in gas composition and extraction systems, methane emissions sources from fossil fuel infrastructure are fairly comparable. Typically, leaks are highly distributed over multiple point sources that include thousands of components like valves, connectors, seals, etc or various points along the millions of km of transmission and distribution pipelines. Each of the components are prone to leaking to varying degrees and at unpredictable times. For this reason, any global effort to reduce fossil-based methane emissions would require mitigation policy that follows the broad recommendations discussed here.

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APPENDIX D

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February 22, 2018

Mr. Peter Tsirigotis, Director
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U.S. Environmental Protection Agency
Mail Code: D205-01
109 T. W. Alexander Drive
Durham, NC 27709

Re: Leak Monitoring Data Analysis in Support of EPA's Reconsideration of the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule"

Dear Mr. Peter Tsirigotis:

The American Petroleum Institute ("API") is pleased to submit the attached information in support of EPA's reconsideration of the New Source Performance Standards ("NSPS") 40 C.F.R. Part 60 Subpart OOOOa, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule" 81 Fed. Reg. 32826 (June 3, 2016).

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Most of our members conduct oil and gas development and production operations and are directly impacted by the final rule.

Throughout the development of the 2012 oil and gas NSPS rule and its amendments in 2016, API has constructively engaged with the agency to provide operational knowledge and emissions data to inform these important rules. During this time, our objective has remained the identification of cost-effective emission control requirements that reduce VOC emissions for new sources and, as a co-benefit, also reduce methane emissions.

Following publication of the 2016 NSPS rule, API filed a petition with EPA seeking administrative reconsideration of certain requirements in the final rule. In the petition, API also included issues where changes to the rule were needed. These issues were included because, were EPA to grant reconsideration of any issues, it would be efficient for EPA to make these changes during the reconsideration process. Among the supplemental list of issues was a recommendation that the agency revisit the leak detection and repair survey frequencies for both well sites and compressor stations.

To further support this recommendation, API initiated an analysis (see attached) following data collection from companies to determine how the implementation of leak monitoring and repair programs might further inform a reduced leak survey frequency. Based on our analysis, it was determined that the initial or uncontrolled leak incidence – the number of components found leaking divided by total number of components surveyed – is significantly lower than the basis of EPA's original rule analysis. A lower initial leak incidence results in a lower baseline mass of emissions from leaks. Using EPA's cost effectiveness calculations with the lower initial leak incidence of 0.4% calculated from this analysis, it is clear that leak detection and repair programs at oil and gas well sites are not cost-effective, even under the multi-pollutant scenario EPA utilized in the rulemaking. This conservative analysis supports justification for a reduced survey frequency at well sites from semi-annual to annual. While the revised analysis results in a value greater than the agency's historical threshold of cost-effective control, the recommendation for an annual frequency is based on established industry practice for new operations. API requests that EPA review this new information as the agency reconsiders Subpart OOOOa. An electronic version of this analysis can be made available upon request.

Please contact me at toddm@api.org or 202-682-8319 with any additional questions regarding the content of this submittal.

Sincerely,

/s/

Matthew Todd

cc: Mandy Gunasekara, USEPA
Penny Lassiter, USEPA
David Cozzie, USEPA

API's Leak Monitoring and Repair Analysis in Support of EPA's Reconsideration of "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule"

81 Fed. Reg. 35826 (June 3, 2016)

1. Background

As noted in API's December 4, 2015 comments on the proposed Subpart OOOOa, EPA overestimated the environmental benefit from leak detection and repair (LDAR) programs at oil and natural gas facilities, while at the same time underestimating the costs associated with implementation of LDAR programs. As a result, EPA underestimated the cost of control ($/ton) of LDAR at well sites and compressor stations as documented in EPA's Technical Support Document (TSD) that accompanied the final Subpart OOOOa rule[1].

Since the time of the proposal of Subpart OOOOa, API member companies have established LDAR programs as part of both voluntary and regulatory efforts (e.g., Subpart OOOOa, CO, WY, CA, OH, PA, etc.). API previously shared results of some such programs in Colorado and in the Barnett Shale area of Texas in our August 2, 2016 petition for reconsideration. That data indicated an average leak incidence of 0.2% of the total components surveyed that were found leaking based on annual survey data. Similarly, Chevron submitted comments during the original rulemaking sharing their observed leak incidence range between 0.04 to 0.16%[2]. In an effort to develop a larger data set across a wider range of companies and operating areas, API conducted a blinded survey of available LDAR data to review the actual initial leak incidence being observed by operators.

2. API LDAR Survey and Initial Leak Incidence Assessment

API completed a blinded survey of operating companies that resulted in the collection of data from LDAR surveys completed using optical gas imaging (OGI) from six (6) member companies.[3] The data cover a wide range of operators and facility types at sites located in more than 14 states[4]. Only the results from the initial leak survey (the first survey) conducted at an individual

[1] https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631
[2] https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-6929
[3] These six companies provided data specific to count of leaks identified during each leak survey and also provided equipment information for the site in order to derive the total count of components at each site where a survey was conducted.
[4] This includes sites located in Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

well site was considered for this analysis. Following are key summary statistics from the LDAR surveys for determining the initial leak incidence rate at well pads:

- Six (6) companies providing LDAR survey results at well site locations
- 4,117 well sites
  - 1,841 Oil well sites
    - 1,164 single well sites
    - 677 multi well sites
  - 2,276 Gas well sites
    - 1,521 single well sites
    - 755 multi well sites
- 1,958,033 components surveyed
  - 95,187 components available directly from actual component count data provided for 93 sites
  - 1,862,846 estimated components based on major equipment count information for 4,024 sites using the default average component counts for onshore natural gas and crude oil production equipment as listed in 40 CFR Part 98, Subpart W Table W-1B and Table W-1C.

Utilizing the number of leaks found at the 4,117 surveyed well sites, the average initial leak incidence for all well sites was determined to be 0.4% of components surveyed. This leak incidence indicates that for sites just beginning an LDAR program – that is sites for which no organized leak detection and repair efforts had previously been made, only 4 out of every 1,000 components surveyed were found to be leaking. Table 1 below summarizes the API member company leak data.

Table 1. Summary of Initial Leak Incidence Assessment

Number of Well Sites Included in Analysis	4,117
Estimated Number of Total Components Surveyed	1,958,033
Number of Leaking Components Detected using OGI	7,838
Leak Incidence Rate	0.4%

3. EPA Leak Rate Assumptions – Subpart OOOOa Basis

In the Subpart OOOOa rulemaking, EPA relied upon various sources of information to estimate the leak incidence rate and associated emissions from leaking components. For determining the number of components that would require repair and the cost associated with repairing those components, EPA estimated that 1.18% percent of components were leaking at well sites. The leak incidence of 1.18% was obtained from Table 5 for baseline gas valves from the memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, *Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011*[5]. Note that the 1.18% percent of leaking components used by EPA to estimate the cost of repair was not directly used to estimate the baseline emissions in EPA's original analysis.

To estimate the emissions from the model well sites used to represent oil and gas facilities, EPA relied upon emission rates (kg/hr/source) for components in gas service from Table 2-4 of EPA-453/R-95-017 "*Protocol for Equipment Leak Emission Estimates*[6] *(EPA Protocol)*. As described in the EPA Protocol, the values in Table 2-4 were derived from studies completed by EPA and API in the early 1990s. Appendix C of the EPA Protocol provides additional details regarding the derivation of the data in Table 2-4. Notably, Table C-1 indicates that data from only 775 total components were considered in the development of the average emission factors, of which only 368 were from oil and gas production operations.

The EPA Protocol also notes on page 5-54: *"At a process unit, the initial leak frequency can be determined based on collected screening data. If no screening data are available, the initial leak frequency can be assumed to be equivalent to the leak frequency associated with the applicable average emission factor. However, if a process unit already has some type of LDAR program in place, the average emission factor may overestimate emissions."* Table 2-4 is the source of the "applicable average emission factor" for oil and gas facilities.

4. Updated Cost-Effectiveness Values based on New Initial Leak Incidence Data

A more accurate estimate of emissions from oil and gas operations, before the implementation of an LDAR program, can be developed from new leak screening data from API member companies. This assessment consisted of the following step-wise approach, which is described in more detailed in this section:

[5] https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4493&contentType=pdf

[6] https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

A. Utilize correlation equations within EPA's Leak Protocol with Table 2-4 average emission rates to establish the baseline leak incidence rate for each component type embedded within EPA's original analysis.

B. Use the derived leak incidence from Step A for each component type with the number of components in EPA's model plant to obtain the overall average leak incident rate in EPA's original analysis.

C. Re-assess the baseline emission rates for each component type using the actual observed leak incidence of 0.4% in comparison to the overall leak incidence used in EPA's original analysis identified in Step B.

D. Apply new baseline emission rates from Step C for each component in EPA's cost-effectiveness analysis for LDAR.

The EPA Protocol Table 2-4 emission rates from leaks utilized in the calculations supporting the TSD[7] were established to provide estimates of emissions from components that are not yet part of an LDAR program, and when no leak screening data is available. Section 5.3.1 of the EPA Protocol provides correlation equations that can be used to estimate leak emission rates based on the leak incidence (fraction of leaking components). For the case of oil and gas fugitive components, Table 5-7 provides correlation equations that estimate mass emission rates for different leak concentrations levels[8] (in parts per million or ppm). These emission rates are based on the average fraction of components found to be leaking during leak surveys. An example formula from Table 5-7 is shown below for gas connectors at the 10,000 ppm leak definition. All correlation equations have been provided within Attachment B for reference.

$$ALR = (0.026 \times LKFRAC) + 1.0E\text{-}05$$

Where:

ALR = Average leak rate (kg/hr per source)

LKFRAC = Leak fraction

Utilizing the formulas in Table 5-7, it is possible to back calculate the incidence rate (leak fraction) inherent to the average leak emission rates in Table 2-4. Table 2 below provides the summary of the leak incidence rates for all component types calculated using the Table 2-4 average leak emission rates with the corresponding equations at both the 10,000 ppm and

[7] https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631

[8] Table 5-7 correlation equations are stated for leak concentrations at 500 ppm, 1000 ppm, 2000 ppm, 5000 ppm, and 10000. A lower leak definition correlates to a higher incidence rate for each component type and vice versa.

500 ppm leak definition levels. To estimate the overall average leak incidence for a typical well pad, the leak incidence rates for each component were combined with the component counts and number of well pads assumed by EPA to be impacted by Subpart OOOOa in the TSD. This leads to an overall average leak incidence of 0.0165 at the 10,000 ppm leak definition and 0.0250 at the 500 ppm leak definition, versus the 0.004 observed by API members.

Table 2. Summary of Initial Leak Incidence at 10,000 ppm and 500 ppm Derived from EPA's Table 2-4 Uncontrolled Emission Factors and Table 5-7 Correlation Equations from the EPA Leak Protocol

	Derived Leak Incidence Rate (10,000 ppm leak definition)	**Derived Leak Incidence Rate (500 ppm leak definition)**
Valves	0.046	0.064
Flanges	0.005	0.009
Connectors	0.007	0.012
OEL	0.036	0.054
PRV	0.098	0.160
Overall Average Leak Incidence (calculated)[a]	*0.0165*	*0.0250*

a. The overall average was derived from the average leak incidence rates for each component combined with the component counts and number of well pads assumed by EPA to be impacted by Subpart OOOOa in the TSD.

In order to update the uncontrolled leak emission rates, API multiplied the average leak incidence rate for each component (as listed in Table 2 above) by the ratio of the new API average incidence rate (0.004) divided by the EPA average leak incidence rate (0.0165). The resulting updated leak emission rates for each component are provided in Table 3. Note the baseline emissions were conservatively updated using the leak incidence rates at the 10,000 ppm leak definition though OGI detects leaks at much lower leak concentrations[9]. The use of 10,000 ppm is conservative since, in this analysis, it leads to a smaller fraction of components leaking in EPA's basis (albeit at a higher mass rate). This in turn leads to the use of a smaller ratio for updating the uncontrolled leak rate.

[9] EPA states on Pages 41-42 of Subpart OOOOa TSD: *"The OGI camera is capable of viewing leaks at a 500 ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level."*

Table 3. EPA Leak Emission Rate and Updated Leak Emission Rates Based on Lower Observed Initial Leak Incidence

	EPA Table 2-4 Uncontrolled (kg/hr/comp)	Updated Table 2-4 Uncontrolled (kg/hr/comp)[a]
Valves	0.0045	0.0011
Flanges	0.00039	0.00009
Connectors	0.0002	0.00005
OEL	0.002	0.00048
PRV	0.0088	0.00021

a. Emission values updated using 10,000 ppm leak definition.

Next, API used the updated leak rates in Table 3 in place of the original Table 2-4 leak rates to recalculate EPA's analysis presented in its *"Modified Final_Rule_OOOOa_TSD_Section_4_-_OGI_Well_Pad_050216.xlsx"* workbook provided with the TSD, which accompanied the final rule. API also replaced the assumed 1.18% value EPA used to estimate effort to repair leaks with the actual 0.4% observed by API members. In summary, the following two changes were made to EPA's cost-effectiveness analysis:

1. Replace the Table 2-4 average emission rates with the updated leak emission rates provide in Table 3 that reflect the lower overall observed leak incidence rate observed by operators.
2. Replace EPA's assumed 1.18% leak incidence for repairs with the 0.4% leak incidence derived from actual LDAR survey data.[10]

The "Model Plant 2012" tab of EPA's workbook provides cost-effectiveness estimates for implementation of LDAR at quarterly, semiannual, and annual frequencies. The tables in Attachment A of this document provide comparison of the cost effectiveness considering the updated values reviewed by API and described above versus the original values used by EPA. As the first table in Attachment A shows, the updated cost-effectiveness values are approximately 4 times higher than the values EPA originally estimated. As this data clearly shows, if the more accurate representation of initial (uncontrolled) leak incidence from API member data were available at the time of the original rulemaking, LDAR would not have been considered cost-effective, even at an annual frequency.

No other changes were made to the cost-effectiveness calculations in this assessment, even though API has commented previously on numerous issues with the overall approach and

[10] This update has the effect of lowering EPA's cost-effectiveness estimate because EPA directly used the leak incidence of 1.18% to estimate time for repair of components.

analysis conducted for the original rulemaking as it relates to LDAR. As API outlined in our December 4, 2015 comments during the rulemaking, other key issues include:

- EPA underestimated the programmatic costs to implement an LDAR program for oil and gas sites.
- EPA applied incorrect values for emissions reductions that would occur for different leak frequencies (i.e., annual, semi-annual, quarterly) and the actual reductions are less than EPA assumed.
- EPA overestimated component counts for the model plant gas and oil well sites, thus overstating baseline emissions.

If the above issues were also addressed and corrected, the result would be to further increase the cost-effectiveness ($/ton) value associated with applying LDAR. For instance, applying the correct 50% control factor for semi-annual LDAR instead of the 60% used by EPA would increase the Cost of Control ($/ton) values for semi-annual LDAR by a factor of 1.2. This analysis supports justification for a reduced survey frequency at well sites from semi-annual to annual.

ATTACHMENT A

LDAR Cost Effectiveness Estimates

(Updated and Original EPA Multi-Pollutant Values)

API Updated Cost-Effectiveness Analysis

Model Plant 2012 - Multi Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$759	$1,094	$971	0.53	0.148	$1,027	$912	$3,696	$3,279	1,782	495	$2,539,249	$3,661,461	$3,248,433
Oil Well Sites (GOR < 300)	6,812	$759	$1,094	$1,067	0.12	0.032	$4,574	$4,458	$17,051	$16,619	815	219	$5,169,565	$7,454,236	$7,265,331
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$759	$1,094	$1,033	0.27	0.073	$2,053	$1,937	$7,504	$7,081	2,486	680	$7,080,452	$10,209,633	$9,633,275
All Wells Weighted Averages							**$2,098**	**$1,982**	**$7,648**	**$7,226**					
Semi-Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$801	$1,837	$1,652	0.80	0.222	$1,150	$1,034	$4,137	$3,720	2,673	743	$2,679,903	$6,147,634	$5,528,092
Oil Well Sites (GOR < 300)	6,812	$801	$1,837	$1,796	0.18	0.048	$5,119	$5,004	$19,086	$18,654	1,222	328	$5,455,917	$12,515,746	$12,232,388
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$801	$1,837	$1,745	0.40	0.109	$2,298	$2,182	$8,400	$7,976	3,730	1,020	$7,472,651	$17,142,089	$16,277,552
All Wells Weighted Averages							**$2,348**	**$2,232**	**$8,561**	**$8,138**					
Quarterly Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$885	$3,323	$3,076	1.07	0.296	$1,560	$1,444	$5,613	$5,196	3,564	991	$2,961,210	$11,119,981	$10,293,924
Oil Well Sites (GOR < 300)	6,812	$885	$3,323	$3,268	0.24	0.064	$6,945	$6,829	$25,893	$25,461	1,630	437	$6,028,620	$22,638,766	$22,260,955
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$885	$3,323	$3,200	0.53	0.146	$3,118	$3,002	$11,395	$10,972	4,973	1,361	$8,257,050	$31,007,000	$29,854,284
All Wells Weighted Averages							**$3,185**	**$3,069**	**$11,614**	**$11,191**					

While API outlined additional issues with the overall approach for estimating costs and benefits of implementing LDAR in our December 4, 2015 comments, only the following changes were made in this analysis:

1) Replaced the Table 2-4 emission rates with the updated leak emission rates that reflect the lower observed leak incidence rate, and

2) Replaced EPA's assumed 1.18% leak incidence for repair costs with the 0.4% leak incidence derived from actual LDAR survey data observed by operators.

EPA 's Original Cost Effectiveness (Model Plant 2012 Sheet in "Final_Rule_OOOOa_TSD_Section_4_-_OGI_Well_Pad_050216.xls")

Model Plant 2012 - Multi Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$759	$1,318	$809	2.20	0.611	$300	$184	$1,079	$662	7,355	2,044	$2,539,249	$4,411,155	$2,706,234
Oil Well Sites (GOR < 300)	6,812	$759	$1,318	$1,204	0.49	0.132	$1,335	$1,219	$4,977	$4,545	3,364	902	$5,169,565	$8,980,511	$8,200,737
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$759	$1,318	$1,063	1.10	0.301	$599	$483	$2,190	$1,767	10,263	2,808	$7,080,452	$12,300,083	$9,920,962
All Wells Weighted Averages							***$612***	***$496***	***$2,232***	***$1,810***					
Semi-Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$801	$2,285	$1,521	3.30	0.917	$347	$231	$1,247	$830	11,032	3,067	$2,679,903	$7,647,023	$5,089,641
Oil Well Sites (GOR < 300)	6,812	$801	$2,285	$2,114	0.74	0.199	$1,543	$1,427	$5,752	$5,319	5,046	1,353	$5,455,917	$15,568,296	$14,398,635
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$801	$2,285	$1,903	1.65	0.451	$693	$577	$2,531	$2,108	15,395	4,212	$7,472,651	$21,322,989	$17,754,307
All Wells Weighted Averages							***$708***	***$592***	***$2,580***	***$2,157***					
Quarterly Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$885	$4,220	$3,201	4.40	1.222	$480	$364	$1,726	$1,310	14,710	4,089	$2,961,210	$14,118,757	$10,708,915
Oil Well Sites (GOR < 300)	6,812	$885	$4,220	$3,991	0.99	0.265	$2,136	$2,020	$7,964	$7,532	6,728	1,805	$6,028,620	$28,743,865	$27,184,318
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$885	$4,220	$3,710	2.20	0.602	$959	$843	$3,505	$3,081	20,527	5,616	$8,257,050	$39,368,800	$34,610,558
All Wells Weighted Averages							***$980***	***$864***	***$3,572***	***$3,150***					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on date from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, initial activities planning, notification of initial compliance status, and purchase of M21 monitoring device.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $4/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semi-annual OGI camera monitoring and 80% reduction with quarterly OGI camera monitoring.

APPENDIX E

MEMORANDUM

TO: Kathleen Sgamma
FROM: John Dunham
DATE: April 15, 2018
RE: Review of *Waste Prevention, Production Subject to Royalties, and Resource Conservation: Rescission or Revision of Certain Requirements* (43 CFR 3160 and 3170)

As per your request John Dunham & Associates (JDA) has reviewed the proposed rule *Waste Prevention, Production Subject to Royalties, and Resource Conservation: Rescission or Revision of Certain Requirements* and the cost-benefit analysis of the same as recorded in the Federal Register on February 22, 2018.[1]

The proposed rule revises or eliminates most of the provisions established in an earlier rule entitled *Waste Prevention, Production Subject to Royalties, and Resource Conservation* enacted on November 18, 2016. According to the BLM, the costs resulting from the enacted rule were underestimated and would add regulatory burdens that would encumber energy production. The Agency states that the enacted rule generates fewer benefits that originally estimated, and the compliance costs would exceed the benefits.[2] The estimated net cost of the 2016 rule is now estimated to be between $581 and $945 million over a ten year period (depending on the discount rate used) which is very close to the net cost of between $876 million and $1,170 million estimated by JDA in its 2016 review of the rule.[3] This differs substantially from the net benefits of between $119 million and $245 million estimated at the time of the original rulemaking.[4]

The BLM also recognizes in this revision to the 2016 rule that there would be significant burdens placed on marginal and low-producing wells.[5] This too mirrors JDA's conclusions that the 2016 rule would leave 112.4 million barrels of developable oil in the ground. This equated to a loss of about $528 million in direct economic activity at the time.

The new rule examined the Regulatory Impact Analysis performed by the BLM in 2016 and found that it likely overstated the benefits and underestimated costs.[6] It also recognized that there were other flaws in

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1 Department of the Interior, Bureau of Land Management, *Waste Prevention, Production Subject to Royalties, and Resource Conservation: Rescission or Revision of Certain Requirements*, Federal Register, Volume 83, Number 36, page 7924, February 22, 2018.

2 Ibid.

3 Memorandum to Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance, from Mike Stojsavljevich, John Dunham & Associates, regarding *Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR 3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)*, April 12, 2016. Available from the author at admin@guerrillaeconomics.com

4 U.S. Bureau of Land Management, *Regulatory Impact Analysis for: Revisions to 43 CFR 3100(Onshore Oil and Gas Leasing) and 43 CFR 3600 (Onshore Oil and gas Operations)*, at: www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.11216.File.dat/VF%20Regulatory%20Impact%20Analysis.pdf

5 Op. cit. Federal Register

6 US Bureau of Land Management. *Regulatory Impact Analysis for the Proposed Rule to Rescind or Revise Certain Requirements of the 2016 Waste Prevention Rule*, February 5, 2018

the analysis, many of which were identified in our earlier report. JDA also made these conclusions in a declaration presented in The United States District Court for The District of Wyoming.[7]

At that time, I personally stated that the 2016 RIA was seriously flawed in that it did not meet 10 of the 16 items that the Office of Management and Budget suggests should be included in a proper analysis as per *OMB Circular A-4*, dated September 17, 2003. Most importantly, the 2016 RIA included no alternatives analysis as required by the OMB. The only alternatives to the Rule were different assumptions as to the royalty rate which should not impact the cost/benefit component of the RIA materially, and these were discussed in general terms with no analysis performed and a cost analysis for marginal changes in the rule that reduced the required amount of gas flared. Neither of these is an appropriate alternative, which, as suggested by OMB, would include *a range of potentially effective and reasonably feasible regulatory alternatives including deferral to state or local regulation, the use of economic incentives to encourage the desired behavior, market-oriented approaches, different compliance dates or different requirements depending on firm size*. The main purpose for an RIA is to examine alternatives and weigh the costs and benefit of different approaches to achieving the same goal.

In addition, I reported in the declaration that the so-called benefits reported in the 2016 RIA were not appropriate to include in such an analysis in that they were based on an estimate of environmental benefits that would accrue worldwide. OMB Circular A-4 specifically states that an *analysis should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.* No distinction was made in the Original RIA between benefits accruing to residents of the United States and anyone else. The calculation of benefits to operators from recovered natural gas used in the Original RIA was also flawed in that it based the value on estimates of natural gas prices that were significantly higher than those in effect when the Rule was drafted. The Original RIA bases its recoverable gas prices on a figure of between $3.69 and $5.67 per thousand cubic feet, with a 2017 estimated price of $3.80. The current spot price is well under $3.00 per Mcf.[8]

The 2016 RIA also miscalculated costs. By focusing solely on the engineering costs of the rule, it failed to account for the cost to society of reduced petroleum production that would result from the proposed rules. OMB Circular A-4 clearly states *with regard to measuring costs, you should be sure to include all the relevant costs to society whether public or private.*

Based on its assertion that the original 2016 RIA was fundamentally flawed, the BLM has decided to promulgate new rules that significantly change the requirements under the provisions enacted in 2016. Specifically, the new rules would rescind a number of requirements enacted in 2016:

- Waste Minimization Plans
- Well drilling requirements
- Well completion and related operational requirements
- Pneumatic controller equipment requirements
- Pneumatic diaphragm pump requirements
- Storage vessel requirements
- LDAR requirements

7 *Declaration of John Dunham* In The United States District Court For The District Of Wyoming, State Of Wyoming, et al., Petitioners, and State Of North Dakota, et al., Intervenor-Petitioners, v. United States Department Of The Interior, et al. Respondents, and Wyoming Outdoor Council, et al., Intervenor-Respondents, Civil Case No. 2:16-cv-00285-SWS [Lead] Consolidated with: Case No. 2:16-cv-00280-SWS.

8 Currently the price is about $2.55 per Mcf based on the Henry Hub price as of March 28, 2018, US Department of Energy, Energy Information Administration, *Natural Gas Weekly Update for week ending March 28, 2018*, March 29, 2018, at: www.eia.gov/naturalgas/weekly/#tabs-prices-2

In addition, the proposed rule would modify certain requirements enacted in 2016. These are:

- Gas capture requirements
- Downhole well maintenance and liquids unloading requirements
- Measuring and reporting volumes of gas vented and flared requirements

According to the new Regulatory Impact Analysis prepared by the BLM, these changes would lead to a reduction in costs relative to the baseline scenario in which the 2016 final rule remains in effect, of between $1.320 and $2.025 billion, and a reduction in benefits of between $695 and $1,083 million.[9] This means that the BLM estimates that these proposed changes in the 2016 Rule would have a net benefit of between $578 and $942 million depending on the selected alternative and discount rate assumptions.[10]

Conduct of a Regulatory Impact Analysis:

As part of the rulemaking process, all Federal regulatory agencies are required to conduct a Regulatory Impact Analysis (RIA). While these analyses are designed to determine if a proposed regulation will have a reasonable effect on the environment while not costing society substantial resources, they are also designed to determine if there are other alternative measures that the regulatory agency should take rather than proposing new rules. As suggested in its reasoning behind the proposed modifications, the BLM itself recognized that the original 2016 RIA was significantly flawed.

Two long-standing Presidential Executive Orders require all agencies, including the BLM, to conduct an analysis of the benefits and costs of a proposed significant regulatory action, including a comparison of the benefits and costs of alternative regulatory approaches.[11] Executive Order 12866 requires that all regulatory actions be reviewed by the Office of Management and Budget (OMB) and gave the Office broad powers to review and request revisions to all regulatory proposals.

This same Executive Order requires that an agency, including BLM, "Shall ... propose or adopt a regulation only upon reasoned determination that the benefits of the intended regulation justify (emphasis added) its costs."[12]

The Requirements of an RIA:

According to the Office of Management and Budget (OMB), there are 16 key elements that every Regulatory Impact Analysis (RIA) needs to address.[13] The OMB even provides agencies with a detailed primer on how to conduct an RIA in accordance with its guidelines and the underlying Executive Orders.[14] Additional requirements from the various laws governing RIAs such as the Unfunded Mandates Reform Act and the Regulatory Flexibility Act also need to be met by the BLM.

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9 US Bureau of Land Management. *Regulatory Impact Analysis for the Proposed Rule to Rescind or Revise Certain Requirements of the 2016 Waste Prevention Rule*, February 5, 2018

10 Ibid.

11 Federal Register, Vol. 58, No. 190, *Executive Order 12866 of September 30, 1993*, Monday, October 4, 1993, at: https://www.archives.gov/federal-register/executive-orders/pdf/12866.pdf

12 Ibid.

13 Office of Management and Budget, *Agency Checklist: Regulatory Impact Analysis*, www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/RIA_Checklist.pdf.

14 Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, at: www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf.

The OMB suggests that each agency include are:

1. A reasonably detailed description of the need for the regulatory action;
2. An explanation of how the proposed regulatory action will meet that need;
3. An appropriate baseline assessment of how the world would look in the absence of the proposed action;
4. An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action;
5. An explanation of why the planned regulatory action is preferable to the potential alternatives;
6. An uncertainty analysis;
7. A description and discussion of the distributive impacts of the potential alternatives;
8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action;
9. A clear and transparent table presenting anticipated benefits and costs.

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner;
11. Provide the data, sources and methods used in the RIA to the public via the internet;
12. Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible;
13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible;
14. Explain and support how the benefits of the intended regulation justify its costs;
15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach;
16. Use appropriate discount rates for benefits and costs expected to occur in the future.

In addition to these 16 items, a proper RIA must examine a number of additional impacts including international effects and the effects on small businesses.

Very few RIAs ever fully follow the OMB guidelines, even though they represent best practices for this sort of analysis. This is definitely the case with the original 2016 RIA performed by the BLM. As JDA concluded in an examination of that RIA, not only did the Agency fail to perform 10 of the 16 checklist items, the analysis presented in the 2016 RIA was biased, and used many flawed assumptions.

Critique of the Analysis Prepared by the BLM for the Modified Rule:

This critique examines each of the items suggested by the OMB and outlines particular issues with how the BLM performed this particular study. Unlike the original RIA, it appears as if the BLM took the analysis more seriously, meeting most of the 16 checklist items.

1. <u>A reasonably detailed description of the need for the regulatory action</u>: **The RIA does document a need for regulatory action on part of the BLM.** According to the RIA, on March 28, 2017, the President issued E.O. 13783, "Promoting Energy Independence and Economic Growth." Section 7(b) of that order directs the Secretary of the Interior to review four specific rules, including the 2016 final rule, for "consistency with the policy set forth in section 1 of [the] order and, if appropriate . . . publish for notice and comment proposed rules suspending, revising, or rescinding those rules." The policy set forth in Section 1 of E.O. 13783 is that "it is in the national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation." (Section 1 (a)). Further, "it is also the policy of the United States that necessary and

appropriate environmental regulations comply with the law, are of greater benefit than cost, when permissible, achieve environmental improvements for the American people, and are developed through transparent processes that employ the best available peer-reviewed science and economics" (Section 1 (e)).

The BLM reviewed the 2016 final rule and is undertaking two regulatory actions as a result of that review, as directed by this Executive Order, and by Secretarial Order No. 3349, "American Energy Independence." First, on October 5, 2017, the BLM published a proposed rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Delay and Suspension of Certain Requirements," 82 FR 46458 (Oct. 5, 2017). After the public comment period, the BLM finalized that rule on December 8, 2017, which suspended or delaying the implementation of certain requirements of the 2016 final rule until January 17, 2019 (2017 Suspension Rule), 82 FR 58050 (Dec. 8, 2017).

Second, the BLM is proposing a rule entitled, "Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements." This proposed rule would revise the 2016 final rule in a way that tries to reduce previous unnecessary compliance burdens and re-establishes and strengthens the requirements that the 2016 final rule replaced. This proposed rule is the subject of this new Regulatory Impact Analysis.

This revised BLM Rule much like the previous 2016 Rule would still impose net costs, although they are significantly lower.

2. An explanation of how the proposed regulatory action will meet that need: The BLM, with this proposed regulatory action explicitly seeks to reduce to the compliance costs of the 2016 Rule, while also maximizing net benefits. **The RIA outlines in detail how the proposed modifications would meet these requirements.**

3. An appropriate baseline assessment of how the world would look in the absence of the proposed action: **BLM provides a "null analysis" in its RIA.** This null case is what is outlined in the 2016 RIA as listed on page 37 of the RIA.

4. An assessment of potentially effective and reasonably feasible alternatives to the proposed regulatory action: An alternatives analysis is presented; however, it is somewhat general in nature. This is a standard problem with RIAs and while the agency attempted to meet this goal, it could go further. Only two alternatives were proposed: A proposed modifications to the 2016 Rule, and an alternative 2 scenario in which the BLM retains and implements the 2016 final rule's gas capture requirements and the associated measurement/metering requirements while rescinding the operational and equipment requirements addressing vented volumes (i.e., the requirements for pneumatic equipment, storage tanks, liquids unloading, and LDAR).

5. An explanation of why the planned regulatory action is preferable to the potential alternatives: **The BLM documents why the proposed alternative is superior to the others outlined in the RIA.** On pages 7-13 of the RIA, the BLM RIA does explain why their alternatives could be preferable to the current rule which is in effect. The BLM has recognized that the baseline or current rule is extremely harmful to the oil and natural gas industry and will reduce both jobs and production.

6. An uncertainty analysis: **The BLM identifies nine areas where uncertainty can greatly impact its estimates; however, no actual uncertainty analysis is performed which quantifies a range on cost impacts.** The areas of uncertainty are listed on page 37 of the RIA.

7. A description and discussion of the distributive impacts of the potential alternatives: While the RIA contains a section labeled *Distributional Effects*, beginning on page 48, it only examines the impact of the regulations across geographic and business categories. OMB states that the analysis of the distributional effects should examine the impact of the proposed action across the population and economy divided up by a range of demographic and economic categories.[15] **This is not an analysis of the distributional impacts of the proposed rule as laid out in OMB Circular A-4.**

8. A clear, plain-language executive summary including an accounting statement that summarizes the benefit and costs for the regulatory action: **This is included in the analysis**.

9. A clear and transparent table presenting anticipated benefits and costs: **The analysis presents the calculated benefits and costs in a clear table.**

In addition, the OMB states that each regulatory impact analysis:

10. Use the best reasonably obtainable scientific, technical economic information and present it in a clear, complete and unbiased manner: Many RIA documents are based on relatively slim data. The BLM recognized that scientific and technical information used in the prior 2016 RIA was biased or flawed and not peer reviewed. In particular, a 2014 Carbon Limits Study used in the 2016 RIA was identified as not being peer reviewed, nor is data available for commenters to provide a review and highly unreliable.[16] In the current RIA, the BLM referenced another document which also does not have underlying data available for review, the 2016 ICF International study.[17] This study was prepared for the Environmental Defense Fund, and without further analysis or access to underlying data for public review, should also be considered unreliable. While peer review is important, it is not always necessary when the underlying data are made available. **This suggests that the BLM could have worked harder to find better data; however, unlike the 2016 RIA it has been conducted in an unbiased manner.**

11. Provide the data, sources and methods used in the RIA to the public via the internet: While the report is extensively cited, much of the source material is not readily available or is not available without some additional cost. **The BLM does not provide a library of the materials or data used in its analysis that is available to the public without additional cost.**

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15 Specifically Circular A-4 States: *Those who bear the costs of a regulation and those who enjoy its benefits often are not the same people. The term "distributional effect" refers to the impact of a regulatory action across the population and economy, divided up in various ways (e.g., income groups, race, sex, industrial sector, geography). Benefits and costs of a regulation may also be distributed unevenly over time, perhaps spanning several generations. Distributional effects may arise through "transfer payments" that stem from a regulatory action as well. For example, the revenue collected through a fee, surcharge in excess of the cost of services provided, or tax is a transfer payment.*

Your regulatory analysis should provide a separate description of distributional effects (i.e., how both benefits and costs are distributed among sub-populations of particular concern) so that decision makers can properly consider them along with the effects on economic efficiency. See: Office of Management and Budget, *Circular A-4*, September 17, 2003, at: www.whitehouse.gov/omb/circulars_a004_a-4#f.

16 *Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras*, CL Report CL-13.27, Carbon Limits, March 2014.

17 *Leak Detection and Repair Cost-Effectiveness Analysis*, Prepared for Environmental Defense Fund by ICF International, December 4, 2015, Revised May 2, 2016.

12. Quantify and monetize the anticipated benefits from the regulatory action to the extent feasible: **The RIA quantifies the benefits from the rule, which it determines to be between $1,320 million and $2,025 million on a net present value basis, or roughly $188 million to $237 million per year**.[18] The BLM's proposed rule would remove almost all of the requirements in the 2016 final rule that were estimated to impose a compliance burden on operators. The 2016 rule estimated that the costs imposed on industry would be between $117 million and $161 million per year on a discounted basis. JDA's estimates of the cost of the 2016 rule were in the neighborhood of $234 million to $348 million.[19] This suggests that the benefits calculated in the proposed rule (that is the mitigation of costs from the 2016 rule) are within reason.

When JDA first estimated the average per well cost of compliance under the 2016 rule, our analysis found that the per well cost of the rule would be as high as $318,967,988 and that as many as 38,000 wells could be impacted for an average per well cost of $8,394. These higher costs would lead to the reduction of about 4,700 wells from production.

Since then, the overall petroleum market has changed dramatically, with much lower prices and operating margins. In addition, there are a larger number of wells on BLM leases in our updated model. Based on the updated (2016 model), the average per well cost of compliance under the prior rule was $7,466 per impacted well.[20] Under the proposed rule, the compliance cost would be $82 per impacted oil well.[21] This includes per-well cost of compliance for several component parts of the 2016 rule; One-time compliance costs (equipment installation, etc.) and future annual costs (LDAR surveys, compliance with narrowing gas capture thresholds).

While the per well costs are small when calculated across the thousands of wells in operation, the impact really falls on marginal wells, since even a small change in costs can make a well producing 1 or even 10 barrels of oil per day unprofitable to operate. Therefore, rather than examining company profit margins, or even average per well costs, it is critical to accurately assess how higher production costs impact the most marginal wells. If the 2016 rule were to remain in effect, under the current pricing structure, it is likely that rather than 4,700 wells being removed from production, prior rule from 2016 were to remain, there would be 12,646 number of marginal wells that would be shut-in, abandoned or plugged because they will have become uneconomic, where the costs associated with operating the well exceed the oil or gas revenue generated. This compares to 678 marginal wells that would be shut-in, abandoned, or plugged based the proposed BLM rule. The table below demonstrates the effect on marginal wells from the revised costs attributed to the 2016 rule versus the proposed rule.

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[18] Op. cit. Regulatory Impact Analysis, page 6.

[19] Memorandum to Kathleen Sgamma, VP of Government & Public Affairs, Western Energy Alliance, from Mike Stojsavljevich, John Dunham & Associates, regarding *Cost-Benefit Analysis of the Impact of Onshore Oil and Gas Leasing (43 CFR 3100), Onshore Oil and Gas Operations (43 CFR 3600), Royalty-Free Use of Lease Production (43 CFR 3178), and Waste Prevention and Resource Conservation (43 CFR 3179)*, April 12, 2016. Available from the author at admin@guerrillaeconomics.com

[20] Note that only oil wells with associated natural gas are impacted. Natural gas wells by their very nature are designed to capture natural gas.

[21] Estimates of BLM wells lost are based on 2016 industry data from IMPLAN and EIA.

Table 1
Marginal Well Impact by State on BLM Leases
(2016 BLM Rule vs. Proposed 2018 Rule)

			2016 Enacted Rule			2018 Proposed Rule		
State	BLM Active Wells	BLM Oil Wells	Estimated Cost	Cost Per Well	Est. Marginal Well Reduction	Estimated Cost	Cost Per Well	Est. Marginal Well Reduction
AZ	1	0	$1,420	$7,466	0	$16	$82	0
CO	6,752	3,296	$24,609,136	$7,466	-1,121	$271,654	$82	-225
ID	-	-	$0	$0	0	$0	$0	0
MT	2,742	1,650	$12,317,670	$7,466	-424	$135,971	$82	-11
ND	2,255	2,211	$16,508,474	$7,466	-12	$182,233	$82	0
NE	31	28	$211,286	$7,466	-8	$2,332	$82	-2
NM	30,563	15,092	$112,680,976	$7,466	-5,323	$1,243,854	$82	-104
NV	97	95	$710,562	$7,466	-42	$7,844	$82	-2
OR	-	-	$0	$0	0	$0	$0	0
SD	84	62	$466,601	$7,466	0	$5,151	$82	-15
UT	8,879	4,885	$36,470,000	$7,466	-932	$402,582	$82	-60
WA	-	-	$0	$0	0	$0	$0	0
WY	32,294	10,681	$79,744,572	$7,466	-4,782	$880,278	$82	-259
Total	83,698	38,000	$283,720,696	$7,466	-12,646	$3,131,915	$82	-678

The economic life cycle of an oil and natural gas well is complex. Many wells are drilled and their production never meets expectation. Other wells may produce large amounts of petroleum for a few years, and then continue to produce at lower levels over time. In this analysis, marginal wells are defined as those that produce an average of less than 15 barrels of oil equivalent per day. A well may also be economically marginal for a number of other reasons, including high production costs due to a remote location far from necessary infrastructure, a well that is has exhausted its ability to produce without expensive re-completion, or perhaps high co-production of substances that must be separated out and disposed. Examples would include saline water, non-burnable gasses mixed with the natural gas. A key economic concept that should be understood is the oil and gas industry pricing structure can vary due to global supply and demand dynamics. Marginal wells become unprofitable to produce whenever oil and/or gas prices drop below a fluctuating crucial price point, or when costs are increased either through regulation or operational dynamics.

BLM had stated in its 2016 RIA that the per company profit margin was 0.15 percent. However, and as can be seen in table 1 above, this likely does not account for the dynamic in which marginal wells and losses associated with them can drag industry profit pools to zero or negative. Therefore, per-well cost is the only appropriate metric for determining the Rule's impacts.

Operators may choose to keep marginal wells if costs are low and the price of oil or recovered gas is high. The model used to initially analyze the effects of the 2016 Rule (both by JDA and by the BLM) assumed much higher prices than today, Higher prices can allow producers to keep wells active even when costs rise; however, at the current wellhead prices for both oil and natural gas, the impact of even small cost increases can be very dramatic. This is why JDAs newest model predicts that many more wells would be shut-in that was the case in 2016. It is also possible that higher operational costs would preclude some new development since the break-even point would be raised.

While the 2016 analysis generally underestimated the number of wells that could be shut-in, it also overestimated the barrels of production lost. In 2016 JDA forecast that a reduction of over 112 million barrels of oil production due to the rule. This was an overestimate as it was based on average production per well in each state. Using a more sophisticated model where wells are classified across

22 production categories, the figure would have been much lower – about 8.5 million barrels.[22] Using this same model, the proposed rule would still lead to a reduction of about 768,000 barrels of oil production on BLM and Native American lands.

Table 2
Estimated Lost Oil Production

	Initial 2016 Model			Revised 2016 Rule Estimate			Proposed Rule Estimate		
State	Well Loss Estimate	Lost Barrels Est.	Barrels Per Day Per Lost Well	Well Loss Estimate	Lost Barrels Est.	Barrels Per Day Per Lost Well	Well Loss Estimate	Lost Barrels Est.	Day Per Lost Well
AZ	-	-	-	0	36	1.5	104	156,272	4.1
CO	934	4,664,186	13.7	1,121	556,291	1.4	225	28,156	0.3
ID	-	-	-	-	-	-	259	578,275	6.1
MT	115	855,323	20.4	424	185,112	1.2	11	137	0.0
ND	1,335	87,290,963	179.1	12	150	0.0	-	-	-
NE	31	24,849	2.2	8	2,315	0.8	60	4,380	0.2
NM	1,330	12,209,466	25.2	5,323	3,913,220	2.0	-	-	-
NV	-	-	-	42	39,472	2.6	-	-	-
OR	-	-	-	-	-	-	0	-	-
SD	8	2,290	0.8	0	3	0.0	2	970	1.3
UT	416	3,589,667	23.6	932	351,427	1.0	0	5	0.1
WA	-	-	-	-	-	-	15	-	-
WY	537	3,726,608	19.0	4,782	3,431,871	2.0	2	72	0.1
Total	4,706	112,363,352	65.4	12,646	8,479,896	1.8	678	768,266	3.1

Also, there are some areas where the BLM likely overestimated these benefits, in that the new rule still imposes significant administrative costs on operators.

In the RIA, the BLM recognizes that there will still be significant administrative costs to industry even after the proposed rule were to take effect. The agency estimates these to be minor, just $261,973 annually, based on an assumption that 4,010 hours of work would be required.[23] This is likely underestimated for two reasons.

First, the BLM significantly underestimates the number of wells that would be subject to requests for approval for royalty-free testing. The agency suggested that there were 1,111 well sites subject to flaring restrictions in the 2016 RIA. It is expected that operators of these wells would at least apply to be approved by the BLM for royalty-free flaring status for on-lease operations, or during some period of well testing. This means that at least 1,111 administrative filings would be conducted at some point in time so rather than 1,500 hours being spend on these requests, 2,200 hours would be spent.

Second, under the provisions outlined in 43 CFR 3179. In the absence of State regulations for Federal lands and tribal regulations for tribal lands regarding the venting or flaring of oil-well gas, there would be a requirement for an evaluation on case-by-case basis. The RIA suggests that this could take 80 hours of administrative time, but only speculates that 20 of these would be performed per year. Since much of the growth in the industry is occurring in new development areas , it is likely that this would be much more significant. In the 2016 RIA, flare metering rules were expected to

22 When JDA analyzed the RIA for the 2016 rule when it was being proposed, well loss figures were derived based on the costs associated with the proposed rule. The model used to develop these figures was based on a descending cascade of existing wells beginning with the least productive and ending with the most productive. As is the case with this analysis, it was assumed that the most marginal wells would be taken out of production first. As such, the well-loss figures are consistent between the two reports. When figures were developed to estimate the loss of production for the 2016 report, the number of lost wells was multiplied by *average* production in each state. As such, a well producing only a few barrels of oil per day was assigned a much larger production value. This led to an overestimation of lost oil production at that time.

23 This figure represents the administrative burden in the 13 states covered by this analysis. The BLM estimates the total administrative burden across all states at $349,000.

impact 635 sites. This is more likely to be close to the number impacted by this rule, meaning that the number of hours required for compliance would grow from 1,600 to 50,800.

Taking these two changes into account, the proposed rule would still impose about $3.521 million in administrative costs on the industry.

13. Quantify and monetize the anticipated costs from the regulatory action to the extent feasible: **The RIA Does Calculate Costs Associated with the Proposed Rule**. As with benefits, the costs associated with the rescission of the 2016 rule are based on the purported benefits of its enactment. These benefits included the value of increased natural gas production resulting from the emissions restrictions placed on the industry and certain environmental benefits related to *climate change*. According to the 2016 RIA, these benefits ranged from $270 million to $354 million depending on the assumptions.

As JDA reported in 2016, these benefits were grossly overestimated and were based on some major analytical leaps. First, the benefit from the sale of additional natural gas was based on 2008 commodity prices, and the actual price of natural gas had fallen considerably since that time. The RIA for the revised rule corrects for this by using more recent data form the US Department of Energy.

More importantly, the benefits outlined in the 2016 RIA were mainly generated by the monetized value of reduced methane emissions. The calculations of these benefits were based on past Environmental Protection Agency (EPA) analysis and on pronouncements from a Federal interagency working group the estimated the social cost of carbon dioxide.

As we reported in detail, this was not a complete analysis and is clearly biased because the EPA never established that those methane emissions that might be prevented by this rule actually impact "climate change" in some way.[24]

Additionally, the entire benefits calculation done by BLM at the time was based on an EPA analysis which in itself is based on an extremely fragile examination of the "climate change" benefits. The values are not derived from any models presented in the study, but rather from a book published in 2000 which purports to measure the cost of supposed "climate change" due to carbon dioxide (CO2) emissions. In sum the 2016 RIA presented little in the way of actual analysis, but rather tied together a number of policy statements. The BLM first determined that the production of oil and gas leads to the emissions of methane and then calculated benefits based on figures determined by the BLM to be self-evident, but which are not supported by facts.

The 2016 RIA also failed to identify benefits that would accrue to citizens of the United States as required by OMB.

The RIA for the revised rule discounts many of the benefits previously identified by the OMB in its calculation of the costs of the rescission. Even so, it still continues to overestimate the costs of potential increased methane emissions. The RIA for the proposed rule only estimates the forgone climate benefits using a measure of the domestic social cost of methane; however, it still uses circular logic to assign a value. In this case it uses *interim values for use in regulatory analyses* established under Executive 13783. Again, these are based on a model of the social cost of carbon dioxide, not methane, and rely on three government assessment models all of which rely on the same underlying data and assumptions as the model used in the prior RIA. As with the 2016 RIA, this analysis does

24 Ibid

not establish that those methane emissions that might be prevented by this rule actually impact "climate change" in some way. In effect the majority of the cost elements outlined in the RIA for the revised rules are likely overestimated in much the same was as they were in 2016.

14. Explain and support how the benefits of the intended regulation justify its costs: All of the benefits calculated for the proposed rule are actually industry cost reductions that occur through the elimination of requirements imposed by the 2016 rule. As such, they are based on a flawed analysis that minimized the overall costs of the 2016 rule (though not to a great extent based on JDA's own analysis).[25] Costs estimates for the proposed rule, on the other hand rely on two criteria, a reduction in the recovery and sale of natural gas and natural gas liquids and the assumed costs of increased methane emissions.

In the new RIA, the BLM likely overestimates these costs in that it assumes that the levels of recoverable natural gas and gas liquids was properly quantified in the 2016 RIA. As was mentioned before, these volumes were speculative in nature, and relied on questionable sources. In addition, even though this new RIA reevaluates the price that operators may receive for recovered natural gas, the price used is still probably too high considering current market conditions.

Additionally, in regard to the purported costs of increase methane emissions, the science is unclear as to whether a social cost benefit exists for reduced methane. As discussed in point 10 above, BLM bases their methane cost estimates on EPA analysis, which rests on a potentially unstable academic foundation. Without further analysis and robust debate, the BLM cannot assume that there is any benefit at all to reduced methane emissions.

Taken as a whole the benefits outlined in the RIA are likely underestimated, while the costs are overestimated, meaning that the net benefits of the proposed rule are likely larger than those calculated by the BLM. **As such, the RIA does support that the benefits of the proposed rule outweigh the potential costs.**

15. Ensure that the preferred option has the highest net benefits unless the law requires a different approach: **A higher net benefit is included in this RIA and it is the preferred option.**

16. Use appropriate discount rates for benefits and costs expected to occur in the future: The BLM discounts its cost estimates using discount rates of three percent and seven percent; however, these are applied individually as separate analyses, and not used to discount effects on private capital (7 percent) and effects on private consumption (3 percent) as suggested by the OMB. **The discounting performed in the RIA is, therefore, not properly conducted.**

The Economic Impact of the Proposed Rules:

The costs that are still imposed by the 2016 rule, even after the effects of the proposed rescission rules would still be large enough to impact the economic dynamics of the oil and gas industry. Based on JDA's dynamic model of the oil and natural gas industry, it is likely these continued administrative costs could lead to that as many as 678 fewer oil wells in operation on Federal and Indian leases (either through a halting of production on marginal wells, or marginal new wells not being drilled and completed). This is based on the assumption that administrative costs will increase by $3.521 million annually, with $3,131,915 of these costs associated with operations in the 13 western states included in this model. As

25 Ibid

Table 3 shows, assuming that marginal wells were no longer economically feasible to operate, this would still result in 768,266 fewer barrels of oil being produced on these leases annually (see Table 2).

By reducing new oil and natural gas development, and potentially reducing continuing operation of marginal fields, the proposed regulations could reduce employment in regions where there are developments on BLM lands. This is particularly important considering that the Federal Government has determined that domestic energy development is a key part of sustaining the current economic recovery.[26] Based on models developed by John Dunham & Associates for Western Energy Alliance, these proposed rules could still result in as many as 169 lost jobs for people directly involved with oil and natural gas development and production, and as many as 421 jobs once all supplier and induced impacts are taken into account.[27] These are real people with real jobs, currently receiving as much as $31.9 million in wages and benefits. All told, the economy could lose as much as $115.7 million in overall economic output annually.

These are economic losses above what would be the baseline cost expectations of the proposed rule.

Table 3
Economic Impact of Proposed Rules

State	Direct Jobs	Total Jobs	Direct Wages	Total Wages	Direct Output	Total Output
Arizona	(0)	(0)	$ (18,873)	$ (27,116)	$ (114,547)	$ (139,722)
Colorado	(70)	(103)	$ (6,981,423)	$ (9,031,976)	$ (24,898,975)	$ (30,188,978)
Idaho	-	-	$ -	$ -	$ -	$ -
Montana	(1)	(1)	$ (51,042)	$ (65,912)	$ (186,393)	$ (234,026)
Nebraska	(0)	(0)	$ (772)	$ (829)	$ (3,117)	$ (3,302)
Nevada	(7)	(25)	$ (538,056)	$ (1,504,704)	$ (1,585,150)	$ (4,554,280)
New Mexico	(18)	(27)	$ (1,416,510)	$ (1,846,641)	$ (5,489,887)	$ (6,801,697)
North Dakota	(0)	(0)	$ (4,407)	$ (6,249)	$ (10,962)	$ (16,340)
Oregon	-	-	$ -	$ -	$ -	$ -
South Dakota	(0)	(0)	$ (2,125)	$ (3,833)	$ (9,429)	$ (16,307)
Utah	(9)	(18)	$ (701,625)	$ (1,118,824)	$ (2,383,257)	$ (3,683,995)
Washington	-	-	$ -	$ -	$ -	$ -
Wyoming	(65)	(79)	$ (6,299,956)	$ (7,009,959)	$ (27,691,247)	$ (29,920,203)
Entire United States	(169)	(421)	$ (16,014,789)	$ (31,920,210)	$ (62,372,964)	$ (115,714,371)

Conclusions:

The Bureau of Land Management has determined that the Regulatory Impact Analysis used to justify natural gas venting rules that were adopted in 2016 was fundamentally flawed. In response, and based on an Executive Order from the President, has issued new rules that dramatically roll-back the 2016 regulations. A careful analysis of the facts laid out in the RIA prepared to examine the costs and benefits of the new proposed rule shows that it was prepared with more attention to both detail and to the regulations regarding RIAs than the prior analysis.

Generally speaking the RIA presents a good analysis of the costs and benefits associated with the rule rescinding the 2016 regulations. At worst, the RIA tends to underestimate the benefits of the new proposed rule and overestimate the costs.

26 See for example: *President Trump Vows to Usher in Golden Era of American Energy Dominance*, Press Release, June 30, 2017, at: https://www.whitehouse.gov/articles/president-trump-vows-usher-golden-era-american-energy-dominance/

27 Based on John Dunham and Associates, *Western Oil & Natural Gas Employs America*, prepared for Western Energy Alliance, 2014, at: www.westernenergyalliance.org/employsamerica

Even if the proposed rule were to be put into effect, there are still substantial compliance costs for the oil and natural gas industries. These are likely underestimated in the RIA and could be as high as $3.521 million annually ($3,131,915 in the 13 western states). This equals $82.40 per operational oil well. This analysis suggests that these costs are likely, and could in and of themselves, lead to reduced production on Federal and Indian owned leases.

Overall, JDA estimates that 678 oil wells will either not be drilled or would be retired as the result of these increased costs. At a minimum this would reduce production from Federal leases by about 768,000 barrels per year. This reduced economic activity would also cost the industry as many as 169 direct and 421 total jobs and would reduce economic activity in the United States by roughly $115.7 billion.

APPENDIX F

EXHIBIT 2

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF WYOMING

STATE OF WYOMING, et al., Petitioners, v. UNITED STATES DEPARTMENT OF THE INTERIOR, et al. Respondents.	)	Civil Case No. 2:16-cv-00285-SWS [Lead] Consolidated with: Case No. 2:16-cv-00280-SWS Assigned: Hon. Scott W. Skavdahl

DECLARATION OF JOHN DUNHAM

I, John Dunham, do certify under penalty of perjury as follows:

1. I am Managing Partner of Guerrilla Economics, LLC, located at 32 Court Street, Suite 207, Brooklyn, New York 11201. I can be contacted at 212.239.2105.

2. I am over the age of twenty one, and I have personal knowledge of the facts stated herein. If called upon to testify as to the matters set forth herein, I would be competent to do so.

3. I am a professional economist with an undergraduate degree from the University of Colorado, a master's degree in economics from the New School of Social Research, and a master's degree in business administration from Columbia University. I have operated an independent economic consulting firm since 2002 and have been qualified as an expert in a number of different cases in both State and Federal courts.

COSTS AND IMPACTS OF THE RULE ARE VASTLY UNDERESTIMATED

4. In its proposed rule, BLM estimated that the proposed rule would pose costs of approximately $117 to $174 million per year, depending on the discount rate used. In the final Rule, BLM adjusted its projections, estimating that the Rule will cost between $110 and $279 million per year. I performed an analysis using the range of potential costs from the proposed rule. My conclusions, however, do not change very much based on the final Rule's estimated costs as they remain within roughly the same range, albeit with a much higher potential cost.

5. My calculations suggest that the cost of implementing the proposed rule would be $319 million per year, which is nearly double BLM's upper estimate of $174 million per year. *See* Table 1.

Table 1
Annual Costs are Nearly Double BLM's Upper Estimate in the Proposed Rule

Impacted Component	Cost per Well	Number of Wells Impacted	Total Cost
Flaring (total including limits and metering)	$ 73,583.00	1,111	$ 81,750,713
Well Completion	$ 7,619.00	1,575	$ 11,999,925
Pneumatic Controllers	$ 384.00	15,600	$ 5,990,400
Pneumatic Pumps	$ 307.69	8,775	$ 2,699,980
Liquids Unloading	$ 3,871.00	1,550	$ 6,000,050
Storage Tanks	$ 20,625.00	3,200	$ 66,000,000
LDAR	$ 3,736.00	38,000	$ 141,968,000
Administrative Burden	$ 67.34	38,000	$ 2,558,920
Total	$ 110,193.03		$ 318,967,987.75

6. While BLM stated that it did not "anticipate a significant number of individual well shut-ins or any lease-wide shut-ins as a result of the [Leak Detection and Repair] requirements," this is simply not the case based on BLM's own cost projections. Oil and natural gas wells are all different, and a large proportion of them are considered low-production, or "marginally economic" (in the 13 western states covered by our model, 67.9 percent of all active wells were considered to be low production, while 80.1 percent of all wells were either dry or low production). Even a modest cost such as $3,736 per well just for Leak Detection and Repair (LDAR) would lead to reduced production. This also does not take into account the reclamation costs that would be involved for wells that were abandoned and shut-in.

7. Based on our dynamic model of the oil and natural gas industry, which prices each component of development in each state and is based on data provided by IMPLAN, Inc., it is likely that as many as 4,700 fewer oil drilling projects would be undertaken as a result of the Rule at 2014 petroleum prices (this may be adjusted slightly under the final Rule's cost projections). Based on 2014 models developed by John Dunham and Associates for Western Energy Alliance, this Rule could result in as many as 1,780 lost jobs directly involved with oil and natural gas development and production, and as many as 3,850 lost jobs once all supplier and induced impacts are taken into account (again, this may be adjusted slightly based on the final Rule). All told, the economy could lose as much as $977.2 million in overall economic output annually.

8. We estimate that the annual fiscal effect of the proposed rules would be as high as $114.1 million, of which $65.6 million represents lost federal taxes. The remaining $48.5 million in lost revenues would be experienced by states and local governments that depend in part on revenues from the development of oil and natural gas fields.

9. Taken together, these direct and economic costs to the economy, using BLM's cost estimates, equate to approximately $1.26 billion in total costs once the Rule is implemented. The costs associated with lost production would continue into the future

BLM'S COST METHODOLOGIES LACK MEANING

10. BLM estimates that the Rule will cost on average between $44,600 and $65,800 per company per year. The BLM does not suggest how it develops per-company compliance costs. Nevertheless, dividing a cost number by a total impacted company count is not relevant. A cost to the largest operator is not the same thing as a cost to a very small operator who is likely to have between three and fifteen employees. For example, a $65,800 cost increase would not even show up on a Fortune 500 company's balance sheet, while it might put a small firm out of business completely. Moreover, it is not plausible that a company with thousands of wells affected by the Rule would only experience an increased cost of $65,000. Rather, larger companies are expected to each experience millions of dollars of costs associated with the Rule.

11. What is important is the additional cost to drill a well. There is a range of profitability for each oil or natural gas well drilled, which depends on numerous factors. The vast majority may not pay out at all, while a few large producers might be extremely profitable. Development firms must take this variability into account when they decide to develop any specific field or play. Increasing the overall average cost would lead companies to decide not to develop marginal opportunities, and this could have a very significant impact on specific companies or locations.

12. The fact BLM failed to estimate the cost of this Rule on a per-well basis or otherwise acknowledge the disparity in profitability on a per-well basis across different sized companies is a fundamental flaw in BLM's cost estimate. Thus, based on BLM's methodology, it is not possible to know the actual implementation costs of the Rule with any certainty or by

any meaningful metric, nor predict with any accuracy how the Rule might affect marginally economic wells or result in permanent well shut-ins.

INACCURATE AND MEANINGLESS CLAIMS ABOUT PROFIT REDUCTIONS

13. BLM claims the Rule will reduce profits by 0.15 percent per company. The claim that company profit margins would be marginally impacted by the rule is based on three key assumptions: (1) the cost per firm is equal to the total compliance cost as calculated by the agency divided by the number of firms; (2) average profit margins are representative of actual company margins; and (3) the profit margins of 26 publicly traded firms is equivalent across all 14,549 firms that BLM claims would be impacted by the rule.

14. None of BLM's assumptions are mathematically correct.

a. First, BLM's upper estimate of the compliance costs of the proposed rule was about $174 million per year, while a more detailed analysis (described above) suggests that the costs could be about double that estimate based on BLM's own assumptions. Since the relationship between costs and profits is not linear, any difference in actual costs would be magnified as more and more marginal companies are impacted.

b. Second, it is incorrect to assume that an average profit margin can be applied across all 14,549 impacted firms. This might be the case if the distribution of profit margins was normal and tight—in other words BLM's analysis assumes that one company is virtually interchangeable with another and they all have very similar cost structures. This is rarely the case with oil and natural gas companies. Drilling companies will have different profit margins than oil service companies. Concluding that all companies have average profit margins is similar to saying that the average of Warren Buffett's income and the average American worker is approximately $1 billion per year. When data are skewed like this an average should never be used in a statistical analysis, rather a median number (a mid-point) is more appropriate.

c. Finally, the analysis assumes that the profit margins for 26 smaller publicly traded companies is a good proxy for the industry. This is simply not true. In order for this survey of firms to be statistically significant, it would require data from about 375 small companies, not just 26. Even more importantly, BLM's analysis only examined small firms not the 318 large firms in the industry, all of which likely have a very different cost and revenue structure. In sum, the claim that profits would be reduced by just 0.15 percent is not supported by the data.

DR. HANNEMAN

15. Dr. Hanneman's opinions are not relevant to the cost of this Rule. Dr. Hanneman is correct in suggesting that Arthur Pigou defined the concept of an externality in the 1920s. However, this is irrelevant to the analysis in question. Dr. Hanneman does not produce any data or analysis as to how the Rule would either alleviate an externality, nor does he do any more than state his opinion that these particular methane emissions create a negative externality in the United States. Even if there are economic externalities associated with global climate change, international costs and benefits are not supposed to be considered as part of a regulatory impact analysis, as BLM does here. Moreover, BLM has applied no analysis to isolate climate change impacts from the Rule to the United States.

16. The use of estimates of the Social Cost of Methane (SCM), which is the only way BLM can justify this rule from a cost-benefit perspective, is highly flawed. Based on the

available literature, there is currently no understanding of exactly how reductions in methane emissions from a limited number of oil and natural gas fields in the United State might impact the general global climate (if at all). The Environmental Protection Agency (EPA) has suggested in an extremely fragile analysis that changes in methane emissions could lead to "climate change" benefits. However, EPA's benefit values were not derived from any study, but rather from a single book published in 2000, which purports to measure the cost of climate change due to carbon dioxide (CO_2) emissions. EPA has acknowledged considerable variation among published estimates on the social cost of non-CO_2 emissions, both in terms of the models and assumptions. Furthermore, none of the other published estimates of the social cost of non-CO_2 greenhouse gases (GHGs) were consistent with the CO_2 estimates developed by an interagency working group (IWG) that included EPA and other executive branch agencies. In short, there is not adequate scientific or economic data or methodology to support the use of the SCM in this rulemaking.

17. BLM relies on EPA's work on SCM, including EPA's suggestion that a paper (Marten, 2014) provides the first set of published methane estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the CO_2 estimates. What BLM fails to mention is that the authors of this paper are all EPA staff. In fact, the Marten article does not even generate its own estimates of the potential economic benefits of reduced methane emissions, but rather calculates estimates of "climate impacts" of methane relative to CO_2. CO_2 and methane are totally different gases, are produced in different places, and have different decay rates. This is why the authors come up with a sizable range of values of from $349 to $1,183 per ton, a 239 percent difference.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct and was executed in Brooklyn, New York on this 21st day of December, 2016.

John Dunham

APPENDIX G

FINAL REGULATION ORDER

California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4

(Note: The entire text of sections 95665, 95666, 95667, 95668, 95669, 95670, 95671, 95672, 95673, 95674, 95675, 95676, and 95677 set forth below is new language in “normal type” proposed to be added to title 17, California Code of Regulations.)

Adopt new Subarticle 13, and sections 95665, 95666, 95667, 95668, 95669, 95670, 95671, 95672, 95673, 95674, 95675, 95676, 95677, Appendix A, Appendix B, and Appendix C, title 17, California Code of Regulations, to read as follows:

Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

§ 95665. Purpose and Scope.

The purpose of this subarticle is to establish greenhouse gas emission standards for crude oil and natural gas facilities located in sectors identified in section 95666. This subarticle is designed to serve the purposes of the California Global Warming Solutions Act, AB 32, as codified in sections 38500-38599 of the Health and Safety Code.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95666. Applicability.

(a) This subarticle applies to owners or operators of equipment and components listed in section 95668 located within California, including California waters, that are associated with facilities in the sectors listed below, regardless of emissions level:

(1) Onshore and offshore crude oil or natural gas production; and,
(2) Crude oil, condensate, and produced water separation and storage; and,
(3) Natural gas underground storage; and,
(4) Natural gas gathering and boosting stations; and,
(5) Natural gas processing plants; and,
(6) Natural gas transmission compressor stations.

(b) Owners and operators must ensure that their facilities, equipment, and components comply at all times with all requirements of this subarticle, including all of the standards and requirements identified in section 95668. Owners and operators are jointly and severally liable for compliance with this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95667. Definitions.

(a) For the purposes of this subarticle, the following definitions apply:

(1) "Air district or local air district" means the local Air Quality Management District or the local Air Pollution Control District.

(2) "Air Resources Board or ARB" means the California Air Resources Board.

(3) "API gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, condensate, produced water, or natural gas. The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.

(4) "Blowout" means the uncontrolled flow of gas, liquids, or solids (or a mixture thereof) from a well onto the surface.

(5) "Centrifugal compressor" means equipment that increases the pressure of natural gas by centrifugal action through an impeller. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purpose of this subarticle.

(6) "Centrifugal compressor seal" means a wet or dry seal around the compressor shaft where the shaft exits the compressor case.

(7) "Circulation tank" means a tank or portable tank used to circulate, store, or hold liquids or solids from a crude oil or natural gas well during or following a well stimulation treatment but prior to the well being put into production.

(8) "Commercial quality natural gas" means a mixture of gaseous hydrocarbons with at least 80 percent methane by volume and less than 10 percent by weight volatile organic compounds and meets the criteria specified in Public Utilities Commission General Order 58-A (November 10, 2016), which is incorporated herein by reference.

(9) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas powered pneumatic device, natural gas powered pneumatic pump, or reciprocating compressor rod packing or seal.

(10) "Condensate" means hydrocarbon or other liquid, excluding steam, either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.

(11) "Continuous bleed" means the continuous venting of natural gas from a gas powered pneumatic device to the atmosphere. Continuous bleed pneumatic devices must vent continuously in order to operate.

(12) “Critical component” means any component that would require the shutdown of a critical process unit if that component was shutdown or disabled.

(13) "Critical process unit" means a process unit or group of components that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

(14) “Crude oil” means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.

(15) “Crude oil and produced water separation and storage” means all activities associated with separating, storing or holding of emulsion, crude oil, condensate, or produced water at facilities to which this subarticle applies.

(16) “Emissions” means the discharge of natural gas into the atmosphere.

(17) “Emulsion” means any mixture of crude oil, condensate, or produced water with varying quantities of natural gas entrained in the liquids.

(18) “Equipment” means any stationary or portable machinery, object, or contrivance covered by this subarticle, as set out by sections 95666 and 95668.

(19) “Facility” means any building, structure, or installation to which this subarticle applies and which has the potential to emit natural gas. Facilities include all buildings, structures, or installations which:

(A) Are under the same ownership or operation, or which are owned or operated by entities which are under common control;

(B) Belong to the same industrial grouping either by virtue of falling within the same two-digit standard industrial classification code or by virtue of being part of a common industrial process, manufacturing process, or connected process involving a common raw material; and,

(C) Are located on one or more contiguous or adjacent properties.

(20) “Flash or flashing” means a process during which gas dissolved in crude oil, condensate, or produced water under pressure is released when the liquids are subject to a decrease in pressure, such as when the liquids are transferred from an underground reservoir to the earth’s surface or from a pressure vessel to an atmospheric tank.

(21) “Flash analysis testing” means the determination of emissions from crude oil, condensate, and produced water by using sampling and laboratory procedures used for measuring the volume and composition of gases released from the liquids, including the molecular weight, the weight percent of individual compounds, and a gas-oil or gas-water ratio.

(22) “Fuel gas system” means, for the purposes of this subarticle, any system that supplies natural gas as a fuel source to on-site natural gas powered equipment other than a vapor control device.

(23) “Gas disposal well” means, for the purpose of this subarticle, any well that is used for the subsurface injection of natural gas for disposal.

(24) “Gauge tank” means a tank found upstream of a separator and tank system which is used for measuring the amount of liquid produced by an oil well and receives or stores crude oil, condensate, or produced water.

(25) "Inaccessible component" means any component located over fifteen feet above ground when access is required from the ground; or any component located over six (6) feet away from a platform or a permanent support surface when access is required from the platform.

(26) "Intermittent bleed" means the intermittent venting of natural gas from a gas powered pneumatic device to the atmosphere. Intermittent bleed pneumatic devices may vent all or a portion of their supply gas when control action is necessary but do not vent continuously.

(27) “Leak or fugitive leak” means the unintentional release of emissions at a rate greater than or equal to the leak thresholds specified in this subarticle.

(28) “Leak detection and repair or LDAR” means the inspection of components to detect leaks of total hydrocarbons and the repair of components with leaks above the standards specified in this subarticle and within the timeframes specified in this subarticle.

(29) “Liquids unloading” means an activity conducted with the use of pressurized natural gas to remove liquids that accumulate at the bottom of a natural gas well and obstruct gas flow.

(30) “Natural gas” means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases. Its constituents include the greenhouse gases methane and carbon dioxide, as well as heavier hydrocarbons. Natural gas may be field quality (which varies widely) or pipeline quality.

(31) "Natural gas gathering and boosting station" means all equipment and components located within a facility fence line associated with moving natural gas to a natural gas processing plant, transmission pipeline, or distribution pipeline.

(32) “Natural gas processing plant” means a plant used for the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures.

(33) “Natural gas transmission compressor station” means all equipment and components located within a facility fence line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines, or within natural gas underground storage fields.

(34) "Natural gas transmission pipeline" means a state rate-regulated Intrastate pipeline, or a pipeline that falls under the “Hinshaw Exemption” as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. sections 717-717z.

(35) “Natural gas underground storage” means all equipment and components associated with the temporary subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns. Natural gas storage does not include gas disposal wells.

(36) “Non-associated gas” means natural gas that is not produced as a byproduct of crude oil production but may or may not be produced with condensate.

(37) “Offshore” means all marine waters located within the boundaries of the State of California.

(38) “Onshore” means all lands located within the boundaries of the State of California.

(39) “Operator” means any entity, including an owner or contractor, having operational control of components or equipment, including leased, contracted, or rented components and equipment to which this subarticle applies.

(40) “Optical gas imaging” means an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

(41) “Owner” means the entity that owns or operates components or equipment to which this subarticle applies.

(42) "Photo-ionization detector or PID instrument" means a gas detection device that utilizes ultra-violet light to ionize gas molecules and is commonly employed in the detection of non-methane volatile organic compounds.

(43) “Pneumatic device” means an automation device that uses natural gas, compressed air, or electricity to control a process.

(44) “Pneumatic pump” means a device that uses natural gas or compressed air to power a piston or diaphragm in order to circulate or pump liquids.

(45) "Pond" means an excavation that is used for the routine storage and/or disposal of produced water and which is not used for crude oil separation or processing.

(46) “Portable equipment” means equipment designed for, and capable of, being carried or moved from one location to another and which it resides for less than 365 days. Portability indicators include, but are not limited to, the presence of wheels, skids, carrying handles, dolly, trailer, or platform.

(47) "Portable pressurized separator" means a pressure vessel that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled and is capable of separating and sampling crude oil, condensate, or produced water at the temperature and pressure of the separator required for sampling.

(48) "Portable tank" means a tank that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled.

(49) "Pressure separator" means a pressure vessel used for the primary purpose of separating crude oil and produced water or for separating natural gas and produced water.

(50) "Pressure vessel" means any hollow container used to hold gas or liquid and rated, as indicated by an ASME pressure rating stamp, and operated to contain normal working pressures of at least 15 psig without continuous vapor loss to the atmosphere.

(51) “Production” means all activities associated with the production or recovery of emulsion, crude oil, condensate, produced water, or natural gas at facilities to which this subarticle applies.

(52) “Produced water” means water recovered from an underground reservoir as a result of crude oil, condensate, or natural gas production and which may be recycled, disposed, or re-injected into an underground reservoir.

(53) “Reciprocating natural gas compressor” means equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating supplied by the manufacturer.

(54) “Reciprocating natural gas compressor rod packing” means a seal comprising of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that vents into the atmosphere.

(55) “Reciprocating natural gas compressor seal” means any device or mechanism used to limit the amount of natural gas that vents from a compression cylinder into the atmosphere.

(56) “Separator” means any tank or pressure separator used for the primary purpose of separating crude oil, produced water, and natural gas or for separating natural gas, condensate, and produced water. In crude oil production a separator may be referred to as a Wash Tank or as a three-phase separator. In natural gas production a separator may be referred to as a heater/separator.

(57) "Separator and tank system" means the first separator in a crude oil or natural gas production system and any tank or sump connected directly to the first separator.

(58) "Successful repair" means tightening, adjusting, or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the minimum leak threshold or emission flow rate standard specified in this subarticle.

(59) “Sump” means a lined or unlined surface impoundment or excavated depression in the ground which, during normal operations, is used to separate, store, or hold emulsion, crude oil, condensate, or produced water.

(60) “Tank” means any container constructed primarily of non-earthen materials used for the purpose of storing, holding, or separating emulsion, crude oil, condensate, or produced water and that is designed to operate below 15 psig normal operating pressure.

(61) "Unsafe-to-Monitor Components" means components installed at locations that would prevent the safe inspection or repair of components as defined by

U.S. Occupational Safety and Health Administration (OSHA) standards or in provisions for worker safety found in 29 CFR Part 1910.

(62) "Vapor collection system" means equipment and components installed on pressure vessels, separators, tanks, or sumps including piping, connections, and flow-inducing devices used to collect and route emission vapors to a processing, sales gas, or fuel gas system; to a gas disposal well; or to a vapor control device.

(63) "Vapor control device" means destructive or non-destructive equipment used to control emissions.

(64) "Vapor control efficiency" means the ability of a vapor control device to control emissions, expressed as a percentage, which can be estimated by calculation or by measuring the total hydrocarbon concentration or mass flow rate at the inlet and outlet of the vapor control device.

(65) "Vent or venting" means the intentional or automatic release of natural gas into the atmosphere from components, equipment, or activities described in this subarticle.

(66) "Well" means a boring in the earth for the purpose of the following:

(A) Exploring for or producing oil or gas.
(B) Injecting fluids or gas for stimulating oil or gas recovery.
(C) Re-pressuring or pressure maintenance of oil or gas reservoirs.
(D) Disposing of oil field waste gas or liquids.
(E) Injection or withdraw of gas from an underground storage facility.

For the purpose of this subarticle, wells do not include active observation wells as defined in Public Resources Code Section 3008 subdivision (c), or wells that have been properly abandoned in accordance with Public Resources Code Section 3208.

(67) "Well casing vent" means an opening on a well head that blocks or allows natural gas to flow to the atmosphere or to a vapor collection system.

(68) "Well stimulation treatment" means the treatment of a well designed to enhance crude oil and natural gas production or recovery by increasing the permeability of the formation and as further defined by the Division of Oil, Gas, and Geothermal Resources SB 4 Well Stimulation Treatment Regulations, Title 14, Division 2, Chapter 4, Subchapter 2, Article 2, section 1761(a) (June 16, 2017), which is incorporated herein by reference.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95668. Standards.

The following standards apply at all times to facilities located in sectors listed in section 95666. The availability of an exemption for any particular component or facility, or compliance with one of the standards, does not exempt the owner or operator of a facility from complying with other standards for equipment or processes located at a facility.

(a) *Separator and Tank Systems*

(1) Except as provided in section 95668(a)(2), the following requirements apply to separator and tank systems located at facilities located in sectors listed in section 95666.

(2) The requirements of section 95668(a) do not apply to the following, provided that an owner or operator maintains, and makes available upon request by the ARB Executive Officer, records necessary to verify compliance with the following provisions:

(A) Separator and tank systems that receive an average of less than 50 barrels of crude oil or condensate per day. The average daily production shall be determined using the annual production certified reports submitted to the California Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR) and dividing by 365 days per year.

(B) Separator and tank systems used in non-associated gas production that receive an average of less than 200 barrels of produced water per day. The average daily production shall be determined using the annual production certified reports submitted to the California Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR) and dividing by 365 days per year.

(C) Separator and tanks systems that are controlled as of January 1, 2018 with the use of a vapor collection system approved for use by a local air district.

(D) Separator and tank systems that are controlled using a gas blanket system to protect tanks from corrosion.

(E) Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

(F) Tanks used for temporarily separating, storing, or holding liquids from any newly constructed well for up to 90 calendar days following initial production from that well provided that the tank is not used to circulate liquids from a well that has been subject to a well stimulation treatment.

(G) Tanks used for temporarily separating, storing, or holding liquids from wells undergoing rework or inspection for up to 90 calendar days provided they are not used to circulate liquids from a well that has been subject to a well stimulation treatment.

(H) Tanks that recover an average of less than 10 gallons per day of any petroleum waste product from equipment provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the amount of liquid recovered. The average daily production shall be determined by using annual production and dividing by 365 days.

(I) Gauge tanks with a capacity of less than or equal to 100 barrels.

(3) By January 1, 2018, owners or operators of existing separator and tank systems that are not controlled for emissions with the use of a vapor collection system shall conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system.

(4) Beginning January 1, 2018, owners or operators of new separator and tank systems that are not controlled for emissions with the use of a vapor collection system shall conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system within 90 days of initial system startup.

(5) Flash analysis testing shall be conducted as follows:

(A) Testing shall be conducted in accordance with the ARB Test Procedure for Determining Annual Flash Emission Rate of Gaseous Compounds from Crude Oil, Condensate, and Produced Water as described in Appendix C.

(B) Testing shall be conducted so that no crude oil, condensate, or produced water is diverted through a gauge tank that is open to the atmosphere and located upstream of the separator and tank system while testing is conducted.

(C) Calculate the annual methane emissions for the crude oil, condensate, and produced water using the test results provided by the laboratory.

(D) Sum the annual methane emissions for the crude oil, condensate, and produced water.

(E) Maintain a record of flash analysis testing as specified in section 95672 and report the results to ARB as specified in section 95673.

(F) The ARB Executive Officer may request additional flash analysis testing or information in the event that the test results reported do not reflect representative results of similar systems.

(G) An owner or operator may perform additional flash analysis testing within a single calendar year and use the average of all results within the calendar year to determine the annual emissions from the separator and tank system, provided that all test reports used in the averaging calculation are maintained and reported as specified in sections 95672 and 95673 of this subarticle.

(6) By January 1, 2019, owners or operators of an existing separator and tank system with an annual emission rate greater than 10 metric tons per year of methane shall control the emissions from the separator and tank system and uncontrolled gauge tanks located upstream of the separator and tank system with the use of a vapor collection system as specified in section 95671.

(7) Beginning January 1, 2018, owners or operators of new separator and tank systems with an annual emission rate greater than 10 metric tons per year of methane shall control the emissions from the separator and tank system and uncontrolled gauge tanks located upstream of the separator and tank system with the use of a vapor collection system as specified in section 95671 within 180 days of conducting flash analysis testing.

(8) Beginning January 1, 2019, owners or operators of a separator and tank system with an annual emission rate less than or equal to 10 metric tons per year of methane shall conduct flash analysis testing and reporting annually. If the results of three consecutive years of test results show that the system has an annual emission rate of less than or equal to 10 metric tons per year of methane the owner or operator may reduce the frequency of testing and reporting to once every five years.

(A) After the third consecutive year of testing, if the annual crude oil, condensate, or produced water throughput increases by more than 20 percent after one year from the date of previous flash analysis testing, then the annual methane emissions shall be recalculated using the laboratory reports from previous flash analysis testing.

(B) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the revised flash emission calculation as specified in Appendix A, Table A1 and shall report the results to ARB within 90 days as specified in section 95673 of this subarticle.

(b) *Circulation Tanks for Well Stimulation Treatments*

(1) By January 1, 2018, owners or operators of circulation tanks that conduct well stimulation treatments at facilities located in sectors listed in section 95666 shall implement a best practices management plan that is designed to limit methane emissions from circulation tanks, and shall make that plan available upon request by the ARB Executive Officer. Each plan must contain a list of best practices to address the following issue areas:

(A) Inspection practices to minimize emissions from circulation tanks.
(B) Practices to minimize venting of emissions from circulation tanks.
(C) Practices to minimize the duration of liquid circulation.
(D) Alternative practices to control vented and fugitive emissions.

(2) By January 1, 2019, each owner or operator that conducts well stimulation treatments shall provide the ARB Executive Officer with a written report that details the results of equipment used to control emissions from circulation tanks with at least 95 percent vapor collection and control efficiency as follows:

(A) Each owner or operator, individually or as part of a group of owners and operators, must conduct a technology assessment and emissions testing in at least three different production fields from wells with different characteristics, such as depth of well or API gravity of crude oil or condensate.

1. Individual owners or operators may conduct a technology assessment and emissions testing within one or more production fields and submit the results to ARB, which will be combined with technical assessments performed by other owners or operators, until at least three reports are submitted from three different production fields.

(B) Each owner or operator or group of owners and operators must notify the ARB Executive Officer prior to conducting the technology assessment and provide an explanation of equipment to be evaluated and plans for emissions testing.

(C) The technology assessment shall include, but is not limited to, the following information relating to vapor collection and control equipment:

1. List of vapor collection and control equipment evaluated;

2. Test results demonstrating the functionality, emissions results, and technical feasibility of the equipment with written statements provided by equipment manufacturers;
3. Costs of the equipment;
4. Safety aspects related to the installation of the equipment;
5. Test results that provide the fuel flow rate and Higher Heating Value of gas collected; and
6. Test results that provide the report shall include the results of testing conducted by the owner or operator or equipment manufacturers that demonstrate the vapor collection and control efficiency and methane, criteria pollutant, and toxic air contaminant emissions before and after installation of the equipment.

(3) The ARB Executive Officer will review the results of the technology assessment and emissions testing specified in section 95668(b)(2) and provide a determination on the installation of vapor collection and control equipment by no later than July 1, 2019.

(4) By January 1, 2020, an owner or operator that conducts well stimulation treatments shall control emissions from circulation tanks with at least 95 percent vapor collection and control efficiency, unless the ARB Executive Officer makes a determination that controlling emissions is not possible for reasons identified in the technology assessment specified in section 95668(b)(2).

(A) If ARB has not made a determination on the installation of vapor collection and control equipment by July 1, 2019, an owner or operator to whom that determination would apply may continue to operate circulation tanks at a level below 95 percent vapor collection and control efficiency until 180 days after ARB makes the late determination.

(c) *Reciprocating Natural Gas Compressors*

(1) Except as provided in section 95668(c)(2), the following requirements apply to reciprocating natural gas compressors located at facilities located in sectors listed in section 95666.

(2) The requirements of section 95668(c) do not apply to the following:

(A) Reciprocating natural gas compressors that operate less than 200 hours per calendar year provided that the owner or operator maintains, and makes available upon request by the ARB Executive Officer, a record of the operating hours per calendar year.

(3) The following requirements apply to reciprocating natural gas compressors located at onshore or offshore crude oil or natural gas production facilities:

(A) Beginning January 1, 2018, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669; and,

(B) The compressor rod packing or seal shall be tested during each inspection period in accordance with the leak detection and repair requirements specified in section 95669 while the compressor is running at normal operating temperature.

1. If the measurement is not obtained because the compressor is not operating for the scheduled test date and the remainder of the inspection period, then testing shall be conducted within 7 calendar days of resumed operation. The owner or operator shall maintain, and makes available upon request by the ARB Executive Officer, a copy of operating records that document the compressor hours of operation and run dates in order to demonstrate compliance with this requirement.

(C) Beginning January 1, 2019, compressor vent stacks used to vent rod packing or seal emissions shall be controlled with the use of a vapor collection system as specified in section 95671; or,

(D) A compressor with a rod packing or seal leak concentration measured above the minimum leak threshold specified in section 95669 shall be successfully repaired within 30 calendar days from the date of initial measurement.

1. A delay of repair may be granted by the ARB Executive Officer if the owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered.

a. A delay of repair to obtain parts or equipment shall not exceed 30 calendar days, or 60 days from the date from of the initial measurement, unless the owner or operator notifies the ARB Executive Officer to report the delay and provides an estimated time by which the repairs will be completed.

(E) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of a rod packing leak concentration measurement found above the minimum leak threshold as specified in Appendix A, Table A5 and shall report the results to ARB once per calendar year as specified in section 95673 of this subarticle.

(F) A reciprocating natural gas compressor with a rod packing or seal leak concentration measured above the minimum standard specified in section 95669 and which has been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be successfully repaired by the end of the next scheduled process shutdown or within 12 months from the date of the initial leak concentration measurement, whichever is sooner.

(4) The following requirements apply to reciprocating natural gas compressors at natural gas gathering and boosting stations, natural gas processing plants, natural gas transmission compressor stations, and natural gas underground storage facilities located in sectors listed in section 95666 and which are not covered under section 95668(c)(3):

(A) Beginning January 1, 2018, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669, except for the rod packing component subject to section 95668(d)(4)(B); and,

(B) The compressor rod packing or seal emission flow rate through the rod packing or seal vent stack shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature using one of the following methods:

1. Vent stacks shall be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or,

2. Vent stacks shall be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making individual or combined rod packing or seal emission flow rate measurements.

3. If the measurement is not obtained because the compressor is not operating for the scheduled test date and the remainder of the inspection period, then testing shall be conducted within 7 calendar days of resumed operation. The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a copy of operating records that document the compressor hours of operation and run dates in order to demonstrate compliance with this requirement.

(C) Beginning January 1, 2019, compressor vent stacks used to vent rod packing or seal emissions shall be controlled with the use of a vapor collection system as specified in section 95671; or,

(D) A compressor with a rod packing or seal with a measured emission flow rate greater than two (2) standard cubic feet per minute (scfm), or a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by two (2) scfm, shall be successfully repaired within 30 calendar days from the date of the initial emission flow rate measurement.

1. A delay of repair may be granted by the ARB Executive Officer if the owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered.

    a. A delay of repair to obtain parts or equipment shall not exceed 30 calendar days, or 60 days from the date from of the initial measurement, unless the owner or operator notifies the ARB Executive Officer to report the delay and provides an estimated time by which the repairs will be completed.

(E) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the flow rate measurement as specified in Appendix A, Table A7 and shall report the result to ARB once per calendar year as specified in section 95673 of this subarticle.

(F) A reciprocating natural gas compressor with a rod packing or seal emission flow rate measured above the standard specified in section 95668(c)(4)(D) and which has been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be successfully repaired by the end of the next scheduled process shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner.

(d) *Centrifugal Natural Gas Compressors*

(1) Except as provided in section 95668(d)(2), the following requirements apply to centrifugal natural gas compressors located at onshore or offshore crude oil or natural gas production facilities, natural gas gathering and boosting stations, natural gas processing plants, natural gas transmission compressor stations, and natural gas underground storage facilities located in sectors listed in section 95666.

(2) The requirements of section 95668(d) do not apply to the following:

(A) Centrifugal natural gas compressors that operate less than 200 hours per calendar year provided that the owner or operator maintains, and can make available upon request by the ARB Executive Officer, a record of the operating hours per calendar year.

(3) Beginning January 1, 2018, components on driver engines and compressors that use a wet seal or a dry seal shall comply with the leak detection and repair requirements specified in section 95669; and,

(4) The compressor wet seal shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature in order to determine the wet seal emission flow rate using one of the following methods:

(A) Vent stacks shall be equipped with a meter or instrumentation to measure the wet seal emissions flow rate; or,

(B) Vent stacks shall be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making wet seal emission flow rate measurements.

(C) If the measurement is not obtained because the compressor is not operating for the scheduled test date and the remainder of the inspection period, then testing shall be conducted within 7 calendar days of resumed operation. The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a copy of operating records that document the compressor hours of operation and run dates in order to demonstrate compliance with this requirement.

(5) Beginning January 1, 2019, centrifugal compressors with wet seals shall control the wet seal vent gas with the use of a vapor collection system as described in section 95671; or,

(6) A compressor with a wet seal emission flow rate greater than three (3) scfm, or a combined flow rate greater than the number of wet seals multiplied by three (3) scfm, shall be successfully repaired within 30 calendar days of the initial flow rate measurement.

(A) A delay of repair may be granted by the ARB Executive Officer if the owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered.

1. A delay of repair to obtain parts or equipment shall not exceed 30 calendar days, or 60 days from the date from of the initial measurement, unless the owner or operator notifies the ARB Executive Officer to report the delay and provides an estimated time by which the repairs will be completed.

(7) If parts are not available to make the repairs, the wet seal shall be replaced with a dry seal by no later than January 1, 2020.

(8) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the flow rate measurement as

specified in Appendix A, Table A7 and shall report the result to ARB once per calendar year as specified in section 95673 of this subarticle.

(9) A centrifugal natural gas compressor with a wet seal emission flow rate measured above the standard specified in section 95668(d)(6) and which has been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be successfully repaired by the end of the next scheduled process shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner.

(e) *Natural Gas Powered Pneumatic Devices and Pumps*

(1) The following requirements apply to natural gas powered pneumatic devices and pumps located at facilities located in sectors listed in section 95666:

(2) Beginning January 1, 2019, continuous bleed natural gas pneumatic devices shall not vent natural gas to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669.

(A) Continuous bleed natural gas powered pneumatic devices installed prior to January 1, 2016 may be used provided they meet all of the following requirements as of January 1, 2019:

1. No device shall vent natural gas at a rate greater than six (6) standard cubic feet per hour (scfh) when the device is idle and not actuating.

2. All devices are clearly marked with a permanent tag that identifies the natural gas flow rate as less than or equal to six (6) scfh.

3. All devices are tested annually using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and,

4. Any device with a measured emissions flow rate greater than six (6) scfh shall be successfully repaired within 14 calendar days from the date of the initial emission flow rate measurement.

5. The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the flow rate measurement as specified in Appendix A, Table A7 and shall report the result to ARB once per calendar year as specified in section 95673 of this subarticle.

(3) Beginning January 1, 2018, intermittent bleed natural gas powered pneumatic devices shall comply with the leak detection and repair requirements specified in section 95669 when the device is idle and not controlling.

(4) Beginning January 1, 2019, natural gas powered pneumatic pumps shall not vent natural gas to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669.

(5) Continuous bleed natural gas powered pneumatic devices and pumps which need to be replaced or retrofitted to comply with the requirements specified shall do so by one of the following methods:

(A) Collect all vented natural gas with the use of a vapor collection system as specified in section 95671; or,

(B) Use compressed air or electricity to operate.

(f) *Liquids Unloading of Natural Gas Wells*

(1) Beginning January 1, 2018, owners or operators of natural gas wells at facilities located in sectors listed in section 95666 that are vented to the atmosphere for the purpose of liquids unloading shall perform one of the following:

(A) Collect the vented natural gas with the use of a vapor collection system as specified in section 95671; or,

(B) Measure the volume of natural gas vented by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument); or,

(C) Calculate the volume of natural gas vented using the Liquid Unloading Calculation listed in Appendix B or according to the Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Title 17, Division 3, Chapter 1, Subchapter 10, Article 2, Subarticle 5, Section 95153(e) (December 31, 2014), which is incorporated herein by reference; and,

(D) Record the volume of natural gas vented and specify the calculation method used or specify if the volume was measured by direct measurement as specified in Appendix A, Table A2.

(2) Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, a record of the volume of natural gas vented to perform liquids unloading as well as equipment installed in the natural gas well(s) designed to automatically perform liquids unloading (e.g., foaming agent, velocity tubing, plunger lift, etc.) as specified in Appendix A, Table A2

and shall report the results to ARB once per calendar year as specified in section 95673 of this subarticle.

(g) *Well Casing Vents*

(1) Beginning January 1, 2018, owners or operators of wells located at facilities located in sectors listed in section 95666 with a well casing vent that is open to the atmosphere shall measure the natural gas flow rate from the well casing vent annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument); and,

(2) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of each well casing vent flow rate measurement as specified in Appendix A, Table A7 and shall report the results to ARB once per calendar year as specified in section 95673 of this subarticle.

(h) *Natural Gas Underground Storage Facility Monitoring Requirements*

(1) As of the effective date of this subarticle, owners or operators of natural gas underground storage facilities located in sectors listed in section 95666 that have a leak detection protocol approved by the Department of Conservation Division of Oil, Gas, and Geothermal Resources shall continue to implement that plan until a monitoring plan is fully approved by ARB and all monitoring equipment specified in this subarticle is installed and fully operational.

(2) By January 1, 2018, owners or operators of natural gas underground storage facilities listed in section 95666 shall submit to ARB a monitoring plan that contains equipment specifications and procedures for each of the monitoring requirements specified in section 95668(h)(5) of this subarticle; and,

(3) By July 1, 2018, the ARB will approve in full or in part, or disapprove in full or in part, a monitoring plan based on whether it is sufficient to meet the requirements specified in section 95668(h)(5).

(A) Revisions to monitoring plans must be submitted to ARB within 14 calendar days of ARB notification; and,

(B) ARB will approve in full or in part, or disapprove in full or in part, the revisions to the monitoring plan within 14 calendar days of submittal to ARB.

(4) Within 180 days of ARB approval, owners or operators of natural gas underground storage facilities listed in section 95666 shall begin monitoring each facility according to the monitoring plan specified in section 95668(h)(5) of this subarticle.

(5) Each natural gas underground storage facility monitoring plan shall at a minimum contain procedures for validating data and alarms, procedures for documenting the event of a well blowout, and equipment specifications and procedures for performing the following types of monitoring at the facility:

(A) Continuous air monitoring to measure upwind and downwind ambient concentrations of methane at sufficient locations throughout the facility to identify methane emissions in the atmosphere.

1. The monitoring system must have at least one sensor located in a predominant upwind location and at least one sensor located in a predominant downwind location with the ability to continuously record measurements.

a. The upwind and downwind instruments shall have the capability to measure ambient concentrations of methane within minimum 250 ppb accuracy to determine upwind and downwind emissions baselines.

b. The upwind and downwind instruments shall be calibrated at least once annually unless more frequent calibrations are recommended by the equipment manufacturer. Any defective instrumentation shall be repaired or replaced within 14 calendar days from the date of calibration or the discovery of a malfunction.

2. The monitoring system shall have sufficient sensors to continuously measure meteorological conditions at the facility including ambient temperature, ambient pressure, relative humidity, wind speed, and wind direction with the ability to continuously record measurements.

3. The monitoring system must the have the ability to store at least 24 months of continuous instrument data and the ability to generate hourly, daily, weekly, monthly, and annual reports.

4. The monitoring system must have an integrated alarm system that is audible and visible continuously in the control room at the facility and in remote control centers.

5. All data collected by the monitoring system must be made available upon request of the ARB Executive Officer, and reported to ARB annually as specified in section 95673 for publication on an ARB maintained public internet web site.

6. By January 1, 2020, the facility, in conjunction with the ARB Executive Officer, shall establish baseline monitoring conditions for

the facility using at least 12 months of continuous monitoring data; and,

7. The monitoring system shall be programmed to trigger the alarm system at any time the downwind sensor(s) detects a reading that is greater than or equal to four (4) times the downwind sensor(s) baseline or in the event of a sensor failure; and,

8. In the event that an alarm is triggered, the facility owner or operator shall confirm that an alarm condition has occurred and then contact the ARB, the Department of Conservation Department of Oil, Gas, and Geothermal Resources, and the local air district within 24 hours of the alarm trigger to notify the agencies of the alarm condition.

9. The upwind and downwind baseline conditions may be re-evaluated every 12 months for changes in local conditions.

   a. Modifications to baseline conditions must be approved by ARB.

   b. Requests for modification to baseline conditions shall be approved in full or in part, or disapproved in full or in part, by the ARB within 3 months from the date of requested modifications.

(B) Daily or continuous leak screening at each injection/withdrawal wellhead assembly and attached pipelines according to one or both of the following methods:

1. Daily leak screening with the use of United States Environmental Protection Agency (US EPA) Reference Method 21-Determination of Volatile Organic Compound Leaks, (October 1, 2017) which is hereby incorporated by reference, as specified in section 95669 of this subarticle, Optical Gas Imaging, or other natural gas leak screening instruments approved by the ARB Executive Officer.

2. Continuous leak screening with the use of automated instruments and a monitoring system with an alarm system that is both audible and visible in the control room and at remote control centers.

   a. The alarm system shall be triggered at any time a leak is detected above 50,000 ppmv total hydrocarbons or above 10,000 ppmv total hydrocarbons if the 10,000 ppmv leak persists for more than 5 continuous calendar days.

b. The alarm system shall be triggered in the event of a sensor failure.

c. The monitoring system shall use a data logging system with the ability to store at least two (2) years of continuous monitoring data.

d. Quarterly, the alarm system shall be tested to ensure that the system and sensors are functioning properly. Any defective instrumentation shall be repaired or replaced within 14 calendar days from the date of alarm system testing.

e. At least annually, all sensors shall be calibrated unless more frequent calibrations are required by the manufacturer. Any defective instrumentation shall be repaired or replaced within 14 calendar days from the date of calibration.

f. The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, records of monitoring system data, records of calibration, and records of alarm system testing.

3. All leaks identified during daily leak screening or identified by the continuous monitoring system shall be tested within 24 hours of initial leak detection in accordance with US EPA Reference Method 21 (October 1, 2017) excluding the use of PID instruments for total hydrocarbons measured in units of parts per million volume (ppmv) calibrated as methane as specified in section 95669 of this subarticle.

4. All leaks shall be successfully repaired within the repair timeframes specified for each leak threshold as specified in section 95669 of this subarticle.

5. A well blowout at an injection/withdrawal well constitutes a violation of this subarticle.

6. At any time a leak is identified above 50,000 ppmv total hydrocarbons or above 10,000 ppmv total hydrocarbons for more than 5 continuous calendar days, the owner or operator shall confirm that an alarm condition has occurred and then notify the ARB, the California Department of Conservation Division of Oil, Gas, and Geothermal Resources, and the local air district within 24 hours of the initial leak measurement.

7. Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, a record of the initial and final leak concentration measurements for leaks identified during daily leak screening or identified by a continuous leak monitoring system that are measured above the minimum allowable leak threshold as specified in Appendix A Table A5.

8. Owners or operators shall report the results of the initial and final leak concentration measurements for leaks identified during daily leak screening or identified by a continuous leak monitoring system as specified in section 95673 of this subarticle.

(C) In the event of a well blowout, daily Optical Gas Imaging (OGI) of the leak found at the injection/withdrawal head assembly shall be performed in accordance with the following provisions:

1. OGI shall be performed by a technician with a certification or training in infrared theory, infrared inspections, and heat transfer principles (e.g., Level II Thermography or equivalent).

2. OGI video footage of the leak shall be recorded for a minimum of 10 minutes every four (4) hours through the blowout incident; and,

3. OGI video footage of the leak shall be made available upon by request by the ARB Executive Officer for publication on an ARB maintained public internet web site; and;

4. OGI video footage of the leak shall be made publicly available by the facility by posting the video footage on a facility maintained public internet web site throughout the course of the blowout incident.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 41511 and 42710, Health and Safety Code. Reference: Sections 38551, 38560, 39600, 41511 and 42710, Health and Safety Code.

§ 95669. Leak Detection and Repair.

(a) Except as provided in section 95669(b), the following leak detection and repair requirements apply to facilities located in sectors listed in section 95666.

(b) The requirements of this section do not apply to the following:

(1) Components, -- including components found on tanks, separators, wells, and pressure vessels -- that are subject to local air district leak detection and repair requirements if the requirements were in place prior to January 1, 2018.

(2) Components, -- including components found on tanks, separators, wells, and pressure vessels -- used exclusively for crude oil with an API Gravity less than 20 averaged on an annual basis. The average annual API gravity shall be determined using certified reports submitted to the California Department of Conservation Division of Oil, Gas, and Geothermal Resources.

(3) Components incorporated into produced water lines located downstream of a separator and tank system that is controlled with the use of a vapor collection system.

(4) Natural gas distribution pipelines located at a crude oil production facility used for the delivery of commercial quality natural gas and which are not owned or operated by the crude oil production facility.

(5) Components that are buried below ground. The portion of well casing that is visible above ground is not considered a buried component.

(6) Components used to supply compressed air to equipment or instrumentation.

(7) One-half inch and smaller stainless steel tube fittings used to supply natural gas to equipment or instrumentation that have been measured using US EPA Reference Method 21 (October 1, 2017) and verified to be below the minimum allowable leak threshold at startup or during the first leak inspection performed after installation.

(8) Components operating under a negative gauge pressure or below atmospheric pressure.

(9) Components at a crude oil or natural gas production facility that are located downstream from the point of transfer of custody and which are not owned or operated by the production facility.

(10) Temporary components used for general maintenance and used less than 300 hours per calendar year if the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the date when the components were installed.

(11) Well casing vents that are open to the atmosphere which are subject to the requirements specified in section 95668(g) of this subarticle.

(12) Components found on steam injection wells or water flood wells.

(13) Pneumatic devices or pumps that use compressed air or electricity to operate.

(14) A compressor rod packing which is subject to annual emission flow rate testing as specified in section 95668(c)(4)(B) of this subarticle.

(c) Beginning January 1, 2018, all components, including components found on tanks, separators, wells, and pressure vessels not identified in section 95669(b) shall be inspected and repaired within the timeframes specified in this section.

(d) The ARB Executive Officer may perform inspections at facilities at any time to determine compliance with the requirements specified in this section.

(e) Except for inaccessible or unsafe to monitor components, owners or operators shall audio-visually inspect (by hearing and by sight) all hatches, pressure-relief valves, well casings, stuffing boxes, and pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for facilities that are not visited at least once every 24 hours; and,

  (1) Owners or operators shall audio-visually inspect all pipes for leaks or indications of leaks at least once every 12 months.

(f) Any audio-visual inspection specified in 95669(e) that indicates a leak that cannot be repaired within 24 hours shall be tested using US EPA Reference Method 21 (October 1, 2017) within 24 hours after initial leak detection, and the leak shall be repaired in accordance with the repair timeframes specified in this section.

  (1) For leaks detected during normal business hours, the leak measurement shall be performed within 24 hours. For leaks detected after normal business hours or on a weekend or holiday, the deadline is shifted to the end of the next normal business day.

  (2) Any leaks measured above the minimum leak threshold shall be successfully repaired within the timeframes specified in this section.

(g) At least once each calendar quarter, all components shall be tested for leaks of total hydrocarbons in units of parts per million volume (ppmv) calibrated as methane in accordance with US EPA Reference Method 21 (October 1, 2017) excluding the use of PID instruments.

  (1) Optical Gas Imaging (OGI) instruments may be used as a leak screening device, but may not be used in place of US EPA Reference Method 21 (October 1, 2017) during quarterly leak inspections, provided they are approved for use by the ARB Executive Officer and used by a technician with a certification or training in infrared theory, infrared inspections, and heat transfer principles (e.g., Level II Thermography or equivalent training); and,

    (A) All leaks detected with the use of an OGI instrument shall be measured using US EPA Reference Method 21 (October 1, 2017) within two calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in this subarticle.

(2) All inaccessible or unsafe to monitor components shall be inspected at least once annually using US EPA Reference Method 21 (October 1, 2017).

(h) Beginning January 1, 2018 and through December 31, 2019, any component with a leak concentration measured above the following standards shall be repaired within the time period specified:

(1) Leaks with measured total hydrocarbon concentrations greater than or equal to 10,000 ppmv but not greater than 49,999 ppmv shall be successfully repaired or removed from service within 14 calendar days of initial leak detection.

(2) Leaks with measured total hydrocarbon concentrations greater than or equal to 50,000 ppmv shall be successfully repaired or removed from service within five (5) calendar days of initial leak detection.

(3) Critical components or critical process units shall be successfully repaired by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.

(4) A delay of repair may be granted by the ARB Executive Officer under the following conditions:

(A) The owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered.

1. A delay of repair to obtain parts or equipment shall not exceed 30 calendar days from the date identified in Table 2 by which repairs must be made, unless the owner or operator notifies the ARB Executive Officer to report the delay and provides an estimated time by which the repairs will be completed.

(B) A gas service utility can provide documentation that a system has been temporarily classified as critical to reliable public gas system operation as ordered by the utility’s gas control office.

Table 1 - Allowable Number of Leaks
January 1, 2018 through December 31, 2019

Leak Threshold	200 or Less Components	More than 200 Components
10,000-49,999 ppmv	5	2% of total inspected
50,000 ppmv or greater	2	1% of total inspected

Table 2 - Repair Time Periods
January 1, 2018 through December 31, 2019

Leak Threshold	Repair Time Period
10,000-49,999 ppmv	14 calendar days
50,000 ppmv or greater	5 calendar days
Critical Components and Critical Process Units	Next scheduled shutdown or within 12 months, whichever is sooner

(i) On or after January 1, 2020, any component with a leak concentration measured above the following standards shall be repaired within the time period specified:

(1) Leaks with measured total hydrocarbon concentrations greater than or equal to 1,000 ppmv but not greater than 9,999 ppmv shall be successfully repaired or removed from service within 14 calendar days of initial leak detection.

(2) Leaks with measured total hydrocarbon concentrations greater than or equal to 10,000 ppmv but not greater than 49,999 ppmv shall be successfully repaired or removed from service within five (5) calendar days of initial leak detection.

(3) Leaks with measured total hydrocarbon concentrations greater than or equal to 50,000 ppmv shall be successfully repaired or removed from service within two (2) calendar days of initial leak detection.

(4) Critical components or critical process units shall be successfully repaired by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.

(5) A delay of repair may be granted by the ARB Executive Officer under the following conditions:

(A) The owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered.

1. A delay of repair to obtain parts or equipment shall not exceed 30 calendar days from the date identified in Table 4 by which repairs must be made, unless the owner or operator notifies the ARB Executive Officer to report the delay and provides an estimated time by which the repairs will be completed.

(B) A gas service utility can provide documentation that a system has been temporarily classified as critical to reliable public gas system operation as ordered by the utility's gas control office.

Table 3 - Allowable Number of Leaks
On or After January 1, 2020

Leak Threshold	200 or Less Components	More than 200 Components
1,000-9,999 ppmv	5	2% of total inspected
10,000-49,999 ppmv	2	1% of total inspected
50,000 ppmv or greater	0	0

Table 4 - Repair Time Periods
On or After January 1, 2020

Leak Threshold	Repair Time Period
1,000-9,999 ppmv	14 calendar days
10,000-49,999 ppmv	5 calendar days
50,000 ppmv or greater	2 calendar days
Critical Components and Critical Process Units	Next scheduled shutdown or within 12 months, whichever is sooner

(j) Upon detection of a component with a leak concentration measured above the standards specified, the owner or operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of leak detection measurement and the measured leak concentration. The tag shall remain affixed to the component until all of the following conditions are met:

(1) The leaking component has been successfully repaired or replaced; and,

(2) The component has been re-inspected and measured below the lowest standard specified for the inspection year when measured in accordance with US EPA Reference Method 21 (October 1, 2017), excluding the use of PID instruments.

(3) Tags shall be removed from components following successful repair.

(k) Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, a record of all leaks found at the facility as specified in Appendix A, Tables A4 and A5, and shall report the results to ARB once per calendar year as specified in section 95673 of this subarticle.

Additional Requirements

(l) Hatches shall remain closed at all times except during sampling, adding process material, or attended maintenance operations.

(m) Open-ended lines and valves located at the end of lines shall be sealed with a blind flange, plug, cap or a second closed valve, at all times except during operations requiring liquid or gaseous process fluid flow through the open-ended line. Open-ended lines do not include vent stacks used to vent natural gas from equipment and cannot be sealed for safety reasons. Open-ended lines shall be repaired as follows:

(1) Open-ended lines that are not capped or sealed shall be capped or sealed within 14 calendar days from the date of initial inspection.

(2) Open-ended lines that are capped or sealed and found leaking shall be repaired in accordance with the timeframes specified in sections 95669(h) and 95669(i).

(n) Components or component parts which incur five (5) repair actions within a continuous 12-month period shall be replaced with a compliant component in working order and must be re-measured using US EPA Reference Method 21 (October 1, 2017), to determine that the component is below the minimum leak threshold. A record of the replacement must be maintained in a log at the facility, and shall be made available upon request by the ARB Executive Officer.

(o) Compliance with Leak Detection and Repair Requirements:

(1) Between January 1, 2018 and December 31, 2019, no facility shall exceed the number of allowable leaks specified in Table 1 during an ARB Executive Officer inspection as determined in accordance with US EPA Reference Method 21 (October 1, 2017), excluding the use of PID instruments.

(2) On or after January 1, 2020, no facility shall exceed the number of allowable leaks specified in Table 3 during an ARB Executive Officer inspection as determined in accordance with US EPA Reference Method 21 (October 1, 2017), excluding the use of PID instruments.

(3) On or after January 1, 2020, no component shall exceed a leak of total hydrocarbons greater than or equal to 50,000 ppmv during an ARB Executive Officer inspection as determined in accordance with US EPA Reference Method 21 (October 1, 2017), excluding the use of PID instruments.

(4) The failure of an owner or operator to repair leaks within the timeframes specified in this subarticle during any inspection period shall constitute a violation of this subarticle.

(5) Except for the fourth (4^{th}) quarterly inspection of each calendar year, leaks discovered during an operator conducted inspection shall not constitute a violation if the leaking components are repaired within the timeframes specified in this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95670. Critical Components.

(a) By January 1, 2018 or within 180 days from installation, critical components used in conjunction with a critical process unit at facilities located in sectors listed in section 95666 must be pre-approved by the ARB Executive Officer if owners or operators wish to claim any critical component exemptions available under this subarticle.

(1) Critical components that have been designated as critical under an existing local air district leak detection and repair program as of January 1, 2018 are not subject the critical component requirements specified in this subarticle.

(b) Owners or operators must provide sufficient documentation demonstrating that a critical component is required as part of a critical process unit and that shutting down the critical component or process unit would impact safety or reliability of the natural gas system.

(c) A request for a critical component or process unit approval is made by submitting a record of the component or process unit as specified in Appendix A, Table A3 along with supporting documentation to the ARB at the address listed in section 95673(b).

(d) Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, a record of all critical components or process units located at the facility as specified in Appendix A, Table A3.

(e) Each critical component or critical process unit must be identified according to one of the following methods:

(1) Identify each component using a weatherproof, readily visible tag that indicates it as an ARB approved critical component and includes the date of ARB Executive Officer approval; or,

(2) Provide a diagram or drawing of all critical components or the critical process unit upon request by the ARB Executive Officer.

(f) Approval of a critical component may be granted only if owners or operators fully comply with this section. The ARB Executive Officer retains discretion to deny any request for critical component or process unit approval.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95671. Vapor Collection Systems and Vapor Control Devices.

(a) Beginning January 1, 2019, the following requirements apply to equipment at facilities located in sectors listed in section 95666 that must be controlled with the use of a vapor collection system and control device as a result of the requirements specified in section 95668 of this subarticle.

(b) Unless section 95671(c) applies, the vapor collection system shall direct the collected vapors to one of the following:

(1) Sales gas system; or,
(2) Fuel gas system; or,
(3) Gas disposal well not currently under review by the Division of Oil and Gas and Geothermal Resources.

(c) If no sales gas system, fuel gas system, or gas disposal well specified in section 95671(b) is available at the facility, the owner or operator must control the collected vapors as follows:

(1) For facilities without an existing vapor control device installed at the facility, the owner or operator must install a new vapor control device as specified in section 95671(d); or,

(2) For facilities currently operating a vapor control device and which are required to control additional vapors as a result of this subarticle, the owner or operator must replace the existing vapor control device with a new vapor control device as specified in section 95671(d) to control all of the collected vapors, if the device does not already meet the requirements specified in section 95671(d).

(d) Any vapor control device required in section 95671(c) must meet the following requirements:

(1) If the vapor control device is to be installed in a region classified as in attainment with all state and federal ambient air quality standards, the vapor control device must achieve at least 95 percent vapor control efficiency of total emissions and must meet all applicable federal, state, and local air district requirements; or,

(2) If the vapor control device is to be installed in a region classified as non-attainment with, or which has not been classified as in attainment of, all state and federal ambient air quality standards, the owner or operator must install one of the following devices that meets all applicable federal, state, and local air district requirements:

(A) A non-destructive vapor control device that achieves at least 95 percent vapor control efficiency of total emissions and does not result in emissions of nitrogen oxides (NO_x); or,

(B) A vapor control device that achieves at least 95 percent vapor control efficiency of total emissions and does not generate more than 15 parts per million volume (ppmv) NO_x when measured at 3 percent oxygen and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

(e) If the collected vapors cannot be controlled as specified in sections 95671(b) through (d) of this subarticle, the equipment subject to the vapor collection and control requirements specified in this subarticle may not be used or installed and must be removed from service by January 1, 2019, and circulation tanks may not be used and must be removed from service by January 1, 2020.

(f) Vapor collection systems and control devices are allowed to be taken out of service for up to 30 calendar days per calendar year for performing maintenance.

(1) A time extension to perform maintenance not to exceed 14 calendar days per calendar year may be granted by the ARB Executive Officer.

(A) The owner or operator is responsible for maintaining a record of the number of calendar days per calendar year that the vapor collection system or vapor control device is out of service and shall provide a record of such activity at the request of the ARB Executive Officer.

(2) If an alternate vapor control device compliant with this section is installed prior to conducting maintenance and the vapor collection and control system continues to collect and control vapors during the maintenance operation consistent with the applicable standards specified in section 95671, the event does not count towards the 30 calendar day limit.

(3) Vapor collection system and control device shutdowns that result from utility power outages are not subject to enforcement action provided the equipment resumes normal operation as soon as normal utility power is restored. Vapor collection system and control device shutdowns that result from utility power outages do not count towards the 30 calendar day limit for maintenance.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95672. Record Keeping Requirements.

(a) Beginning January 1, 2018, owners or operators of facilities located in sectors listed in section 95666 subject to requirements specified in sections 95668, 95669, 95670, and 95671 shall maintain, and make available upon request by the ARB Executive Officer, a copy of records necessary to verify compliance with the provisions of this subarticle which include the following:

Flash Analysis Testing

(1) Maintain, for at five years from the date of each flash analysis test, a record of the flash analysis testing that shall include the following:

(A) A sketch or diagram of each separator and tank system tested that identifies the liquid sampling location and all pressure vessels, separators tanks, sumps, and ponds within the system; and,

(B) A record of the flash analysis testing results, calculations, and a description of the separator and tank system as specified in Appendix A Table A1; and,

(C) A field testing form for each flash analysis test conducted as specified in Appendix C Form 1; and,

(D) The laboratory report(s) for each flash analysis test conducted.

Separator and Tank Systems

(2) Maintain at least five years of records submitted to the Department of Conservation, Division of Oil, Gas, and Geothermal Resources that document each separator and tank system crude oil, condensate, and produced water throughput.

(3) Maintain at least five years of records that document the basis for an exemption from the separator and tank system requirements as specified in section 95668(a)(2).

Circulation Tanks for Well Stimulation Treatments

(4) Maintain a copy of the best practices management plan as specified in section 95668(b)(1) designed to limit methane emissions from circulation tanks.

Reciprocating Natural Gas Compressors

(5) Maintain, for at least five years from the date of each leak concentration measurement, a record of each rod packing leak concentration measurement found above the minimum leak threshold as specified in Appendix A, Table A5.

(6) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of each rod packing emission flow rate measurement as specified in Appendix A, Table A7.

(7) Maintain, for at least one calendar year, a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection.

(8) Maintain records that provide proof that parts or equipment required to make necessary repairs have been ordered.

Centrifugal Natural Gas Compressors

(9) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of each wet seal emission flow rate measurement as specified in Appendix A, Table A7.

(10) Maintain, for at least one calendar year, a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the wet seal emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection.

(11) Maintain records that provide proof that parts or equipment required to make necessary repairs have been ordered.

Natural Gas Powered Pneumatic Devices

(12) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement as specified in Appendix A, Table A7.

Liquids Unloading of Natural Gas Wells

(13) Maintain, for at least five years from the date of each liquids unloading measurement or calculation, a record of the measured or calculated volume of natural gas vented to perform liquids unloading and equipment installed in the natural gas well(s) designed to automatically perform liquids unloading (e.g., foaming agent, velocity tubing, plunger lift, etc.) as specified in Appendix A Table A2.

Well Casing Vents

(14) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of each well casing vent emission flow rate measurement as specified in Appendix A, Table A7.

Underground Natural Gas Storage

(15) Maintain, for at least five years from the date of each leak concentration measurement, a record of the initial and final leak concentration measurement for leaks identified during daily leak inspections or identified by a continuous leak monitoring system and measured above the minimum allowable leak threshold as specified in Appendix A Table A5.

(16) Maintain, for at least five years, records of both meteorological and upwind and downwind air monitoring data as specified in section 95668(h)(A)(5).

Leak Detection and Repair

(17) Maintain, for at least five years from each inspection, a record of each leak detection and repair inspection as specified in Appendix A Table A4.

(18) Maintain, for at least five years from the date of each inspection, a component leak concentration and repair form for each inspection as specified in Appendix A Table A5.

(19) Maintain records that provide proof that parts or equipment required to make necessary repairs have been ordered.

(20) Maintain gas service utility records that demonstrate that a system has been temporarily classified as critical to reliable public gas operation throughout the duration of the classification period.

Vapor Collection System and Vapor Control Devices

(21) Maintain records that provide proof that parts or equipment required to make necessary repairs have been ordered.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95673. Reporting Requirements.

(a) Beginning January 1, 2018, owners or operators of facilities located in sectors listed in section 95666 subject to requirements specified in sections 95668 and 95669 shall report the following information to ARB by July 1st of each calendar year unless otherwise specified:

Flash Analysis Testing

(1) Within 90 days of performing flash analysis testing or recalculating annual methane emissions, report the test results, calculations, and a description of the separator and tank system as specified in Appendix A, Table A1.

Reciprocating Natural Gas Compressors

(2) Annually, report the leak concentration for each rod packing or seal measured above the minimum leak threshold as specified in Appendix A, Table A5.

(3) Annually, report the emission flow rate measurement for each rod packing or seal as specified in Appendix A, Table A7.

Centrifugal Natural Gas Compressors

(4) Annually, report the emission flow rate measurement for each wet seal as specified in Appendix A, Table A7.

Natural Gas Powered Pneumatic Devices

(5) Annually, report the emission flow rate measurement for each pneumatic device with a designed emission flow rate of less than six (6) scfh as specified in Appendix A, Table A7.

Liquids Unloading of Natural Gas Wells

(6) Annually, report the measured or calculated volume of natural gas vented to perform liquids unloading and equipment installed in the natural gas well(s) designed to automatically perform liquids unloading as specified in Appendix A Table A2.

Well Casing Vents

(7) Annually, report the emission flow rate measurement for each well casing vent that is open to atmosphere as specified in Appendix A, Table A7.

Underground Natural Gas Storage

(8) Within 24 hours of receiving an alarm or identifying a leak that is measured above 50,000 ppmv total hydrocarbons or above 10,000 ppmv total hydrocarbons for more than 5 consecutive calendar days at a natural gas injection/withdrawal wellhead assembly and attached pipelines, the owner or operator shall notify the ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the leak concentration measurement.

(9) Within 24 hours of receiving an alarm signaled by a downwind air monitoring sensor(s) that detects a reading that is greater than four (4) times the downwind sensor(s) baseline, the owner or operator shall notify the ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the emissions measurement.

(10) Quarterly, report the initial and final leak concentration measurement for leaks identified during daily inspections or identified by a continuous leak monitoring system and measured above the minimum allowable leak threshold as specified in Appendix A Table A5.

(11) Annually, report meteorological data and data gathered by the upwind and downwind monitoring sensors.

Leak Detection and Repair

(12) Annually, report the results of each leak detection and repair inspection conducted during the calendar year as specified in Appendix A, Table A4.

(13) Annually, report the initial and final leak concentration measurements for components measured above the minimum allowable leak threshold as specified in Appendix A Table A5.

(b) Reports may be e-mailed electronically to ARB with the subject line “O&G GHG Regulation Reporting” to oil&gas@arb.ca.gov or mailed to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street, PO Box 2815
Sacramento, California 95814

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95674. Implementation.

(a) *Implementation by ARB and by the Local Air Districts*

(1) The requirements of this subarticle are provisions of state law and are enforceable by both ARB and the local air districts where equipment covered by this subarticle is located. Local air districts may incorporate the terms of this subarticle into local air district rules. An owner or operator of equipment subject to this subarticle must pay any fees assessed by a local air district for the purposes of recovering the district's cost of implementing and enforcing the requirements of this subarticle. Any penalties secured by a local air district as the result of an enforcement action that it undertakes to enforce the provisions of this subarticle may be retained by the local air district.

(2) The ARB Executive Officer, at his or her discretion, may enter into an agreement or agreements with any local air district to further define funding, implementation and enforcement processes, including arrangements further specifying approaches for implementation and enforcement of this subarticle, and for information sharing between ARB and local air districts relating to this subarticle.

(3) Implementation and enforcement of the requirements of this subarticle by a local air district may in no instance result in a standard, requirement, or prohibition less stringent than provided for by this subarticle, as determined by the Executive Officer. The terms of any local air district permit or rule relating to this subarticle do not alter the terms of this subarticle, which remain as separate requirements for all sources subject to this subarticle.

(4) Implementation and enforcement of the requirements of this subarticle by a local air district, including inclusion or exclusion of any of its terms within any local air district permit, or within a local air district rule, or registration of a facility with a local air district or ARB, does not in any way waive or limit ARB's authority to implement and enforce upon the requirements of this subarticle. A facility's permitting or registration status also in no way limits the ability of a local air district to enforce the requirements of this subarticle.

(b) *Requirements for Regulated Facilities*

(1) Local Air District Permitting Application Requirements

(A) Owners or operators of facilities or equipment regulated by this subarticle, and who are required by federal, state, or local law to hold local air district permits that cover those facilities or equipment shall apply for local air district permit terms ensuring compliance with this article. This requirement applies to facilities or equipment upon issuance of any new local air district permit covering these facilities or equipment, or upon the scheduled renewal of an existing permit covering these facilities or equipment.

(B) If, after the effective date of this subarticle, any local air district amends or adopts permitting rules that result in additional equipment or facilities regulated by this subarticle becoming subject to local air district permitting requirements, then owners or operators of that equipment or facility must apply for terms in any applicable local air district permits for that equipment or facility that ensure compliance with this subarticle.

(2) Registration Requirements

(A) Owners or operators of facilities or equipment that are regulated by this subarticle shall register the equipment at each facility by reporting the following information to ARB as specified in Appendix A Table A6 no later than January 1, 2018, unless the local air district has established a registration or permitting program that collects at least the following information, and has entered into a Memorandum of Agreement with ARB specifying how information is to be shared with ARB.

1. The owner or operator's name and contact information.

2. The address or location of each facility with equipment regulated by this subarticle.

3. A description of all equipment covered by this subarticle located at each facility including the following:

a. The number of crude oil or natural gas wells at the facility.
b. A list identifying all pressure vessels, tanks, separators, sumps, and ponds at the facility, including the size of each tank and separator in units of barrels.
c. The annual crude oil, natural gas, and produced water throughput of the facility.
d. A list identifying all reciprocating and centrifugal natural gas compressors at the facility.
e. A count of all natural gas powered pneumatic devices and pumps at the facility.

4. The permit numbers of all local air district permits issued for the facility or equipment, and an identification of permit terms that ensure compliance with the terms of this subarticle, or an explanation of why such terms are not included.

5. An attestation that all information provided in the registration is provided by a party authorized by the owner or operator to do so, and that the information is true and correct.

(B) Updates to these reports, recording any changes in this information, must be filed with ARB, or, as relevant, with the local air district no later than January 1 of the calendar year after the year in which any information required by this subarticle has changed.

(3) Owners or operators of equipment subject to this subarticle must comply with all the requirements of sections 95666, 95667, 95668, 95669, 95670, 95671, 95672, 95673, and 95674 of this subarticle, regardless of whether or not they have complied with the permitting and registration requirements of this section.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39603, 39607 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600, 40701, 40702, 41511, 42300, 42301 and 42311, Health and Safety Code.

§ 95675. Enforcement.

(a) Failure to comply with the requirements of this subarticle at any individual piece of equipment subject to this subarticle constitutes a single, separate violation of this subarticle.

(b) Each day, or portion thereof, that an owner or operator is not in full compliance with the requirements of this subarticle is a single, separate violation of this subarticle.

(c) Each metric ton of methane emitted in violation of this subarticle constitutes a single, separate violation of this subarticle.

(d) Failure to submit any report required by this subarticle shall constitute a single, separate violation of this subarticle for each day or portion thereof that the report has not been received after the date the report is due.

(e) Failure to retain and failure to produce any record that this subarticle requires to be retained or produced shall each constitute a single, separate violation of this subarticle for each day or portion thereof that the record has not been retained or produced.

(f) Submitting or producing inaccurate information required by this subarticle shall be a violation of this subarticle.

(g) Falsifying any information or record required to be submitted or retained by this subarticle, or submitting or producing inaccurate information, shall be a violation of this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 38580, 39600, 39601, 39607 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95676. No Preemption of More Stringent Air District or Federal Requirements.

This regulation does not preempt any more stringent requirements imposed by any Air District. Compliance with this subarticle does not excuse noncompliance with any Federal regulation. The ARB Executive Officer retains authority to determine whether an Air District requirement is more stringent than any requirement of this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95677. Severability.

Each part of this subarticle is deemed severable, and in the event that any part of this subarticle is held to be invalid, the remainder of the subarticle shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

Appendix A
Record Keeping and Reporting Forms

Table A1
Flash Analysis Testing Record Keeping and Reporting Form

Tank System ID:	
Testing Date:	
Facility Name:	Air District:
Owner/Operator Name:	Signature*:
Address:	

City:	State:	Zip:
Contact Person:	Phone Number:	

Crude Oil or Condensate Flash Test and Calculation Results

API Gravity	GOR (scf/bbl)	Molecular Weight	WT% CH4	Sample Temp (ºF)	Throughput (bbl/day)	Metric Tons CH4/Yr

Produced Water Flash Test and Calculation Results

GWR (scf/bbl)	Molecular Weight	WT% CH4	Sample Temp (ºF)	Throughput (bbl/day)	Metric Tons CH4/Yr

Days in Operation per Year:	
Combined Annual Methane Emission Rate:	MTCH4/Yr

Separator and Tank System Description

Total Number in Separator and Tank System	Total Number on Vapor Collection
Wells:	
Pressure Vessels:	
Pressure Separators:	
Separators:	
Tanks:	
Sumps:	
Ponds:	

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Table A2
Liquids Unloading Record Keeping and Reporting Form

	Facility Name:		Air District:
	Owner/Operator Name:		Signature*:
	Address:		
City:		State:	Zip:
Contact Person:		Phone Number:	

Date	Well ID	Volume of Natural Gas Vented (Mcf)	Calculation Method or Measured	Automation Equipment**

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.
**Automation equipment includes foaming agent, velocity tubing, plunger lift, etc.

Table A3
Designated Critical Component Form

Facility Name:		Air District:
Owner/Operator Name:		Signature*:
Address:		
City:	State:	Zip:
Contact Person:	Phone Number:	
Component Type:		Approval Date:

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Table A4
Leak Detection and Repair Inspection
Record Keeping and Reporting Form

Inspection Date:		
Facility Name:	Air District:	
Owner/Operator Name:	Signature*:	
Address:		
City:	State:	Zip:
Contact Person:	Phone Number:	
Inspection Company Name:		
Number of Leaks per Leak Threshold Category	Percentage of Total Components Inspected	
1,000 to 9,999 ppmv:		
10,000 to 49,999 ppmv:		
50,000 ppmv or Greater:		
Total Components Inspected:		

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Table A5
Component Leak Concentration and Repair
Record Keeping and Reporting Form

Inspection Date:		
Facility Name:	Air District:	
Owner/Operator Name:	Signature*:	
Address:		
City:	State:	Zip:
Contact Person:	Phone Number:	
Inspection Company Name:		
US EPA Reference Method 21 Instrument Make/Model:		
Instrument Calibration Date:		

Component Type	Initial Leak Concentration (ppmv)	Repair Date	Concentration After Repair (ppmv)

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Table A6
Reporting and Registration Form for Facilities

Date:			
Facility Name:		Air District:	
Facility Address or Location:			
Owner/Operator Name:		Signature*:	
Address:			
City:		State:	Zip:
Contact Person:		Phone Number:	
Crude Oil Annual Throughput: (bbls)		Number of Wells:	
Condensate Annual Throughput: (bbls)		Number of Wells:	
Produced Water Annual Throughput: (bbls)		Number of Wells:	

Description and Size of Separators, Tanks, Sumps and Ponds (bbls)	Description of Natural Gas Compressors	Number of Gas Powered Pneumatic Devices	Number of Gas Powered Pneumatic Pumps

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Table A7
Emission Flow Rate Record Keeping and Reporting Form

Facility Name:		Air District:
Facility Address or Location:		
Owner/Operator Name:		Signature*:
Address:		
City:	State:	Zip:
Contact Person:	Phone Number:	
Type of Equipment or Well ID	Measurement Date	Flow Rate (scfm or scfh)

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Appendix B

Calculation for Determining Vented Natural Gas Volume from Liquids Unloading of Natural Gas Wells

$$E_{scf} = \left(\frac{V * P_1 * T_2}{P_2 * T_1}\right) + (FR * HR)$$

Where:

E_{scf} is the natural gas emissions per event in scf

$V = \pi * r^2 * D$ (volume of the well)

$r = \frac{CD}{2}$ (radius of the well)

CD is the casing diameter in feet

D is the depth of the well in feet

P_1 is the shut-in pressure of the well in psia

P_2 is 14.7 psia (standard surface pressure)

T_1 is the temperature of the well at shut-in pressure in °F

T_2 is 60 °F (standard surface temperature)

FR is the metered flowrate of the well or the sales flowrate of the well in scf/hour

HR is the hours the well was left open to atmosphere during unloading

$$CH_4\ emissions = E_{scf} * MF_{CH_4} * MV * MW_{CH_4} * \left(\frac{metric\ ton}{2204.6lb}\right)$$

Where:

$CH_4\ emissions$ is in metric tons per event

$MF_{CH_4} = \frac{lbmole\ CH_4}{lbmole\ gas}$ (mole fraction of CH_4 in the natural gas)

$MV = \frac{1\ lbmole\ gas}{379.3\ scf\ gas}$ (molar volume)

$MW_{CH_4} = \frac{16lb\ CH_4}{lbmole\ CH_4}$ (molecular weight of CH_4)

Appendix C

Test Procedure for Determining Annual Flash Emission Rate of Gaseous Compounds from Crude Oil, Condensate, and Produced Water

1. PURPOSE AND APPLICABILITY

In crude oil and natural gas production, flash emissions may occur when gas dissolved in crude oil, condensate, or produced water is released from the liquids due to a decrease in pressure or increase in temperature, such as when the liquids are transferred from an underground reservoir to the earth's surface. This procedure is used for determining the annual flash emission rate from tanks used to separate, store, or hold crude oil, condensate, or produced water. The laboratory methods required to conduct this procedure are used to measure methane and other gaseous compounds.

2. PRINCIPLE AND SUMMARY OF TEST PROCEDURE

This procedure is conducted by collecting samples of crude oil or condensate and produced water upstream of a separator or tank where flashing may occur. Samples must be collected under pressure and according to the methods specified in this procedure. If a pressure separator is not available for collecting samples, sampling shall be conducted using a portable pressurized separator.

Two sampling methods are specified for collecting liquid samples and are referenced in GPA Standard 2174-93 Sections 2.1c and 2.1a. The first method requires a double valve cylinder and the second requires a piston-type constant pressure cylinder. Both methods shall be conducted as specified in this procedure.

The laboratory methods specified for this procedure are based on American Standards and Testing Materials (ASTM), US Environmental Protection Agency (US EPA), and Gas Processor Association (GPA) methods. These laboratory methods measure the volume and composition of gases that flash from the liquids, including a Gas-Oil or Gas-Water Ratio, as well as the molecular weight and weight percent of the gaseous compounds. Included are procedures for measuring the bubble point pressure and conducting a laboratory flash analysis. The laboratory results are used with the crude oil or condensate or produced water throughput to calculate the mass of emissions that are flashed from the liquids per year.

3. DEFINITIONS

For the purposes of this procedure, the following definitions apply:

3.1 “Air Resources Board or ARB" means the California Air Resources Board.

3.2 "API Gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, condensate, produced water, or natural gas. The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.

3.3 “Bubble point pressure” means the pressure, at the pressurized sample collection temperature, at which the first bubble of gas comes out of solution.

3.4 “Condensate” means hydrocarbon and other liquid either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.

3.5 “Crude oil” means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.

3.6 “Double valve cylinder" means a metal cylinder equipped with valves on either side for collecting crude oil, condensate, or produced water samples.

3.7 “Emissions” means the discharge of natural gas into the atmosphere.

3.8 “Emulsion” means any mixture of crude oil, condensate, or produced water with varying amounts of natural gas contained in the liquid.

3.9 “Flash or flashing” means a process during which gas dissolved in crude oil, condensate, or produced water under pressure is released when subject to a decrease in pressure, such as when liquids are transferred from an underground reservoir to a tank on the earth’s surface or from a pressure vessel to an atmospheric tank.

3.10 “Floating Piston cylinder” means a metal cylinder containing an internal pressurized piston for collecting crude oil, condensate, or produced water samples.

3.11 “Gas-Oil Ratio (GOR)” means a measurement used to describe the volume of gas that is flashed from a barrel of crude oil or condensate in a separator and tank system.

3.12 “Gas-Water Ratio (GWR)” means a measurement used to describe the volume of gas that is flashed from a barrel of produced water in a separator and tank system.

3.13 “Natural gas” means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases, of which its constituents include methane, carbon dioxide, and heavier hydrocarbons. Natural gas may be field quality (which varies widely) or pipeline quality.

3.14 “Operating pressure” means the pressure of the vessel from which a sample is collected. If no vessel pressure gauge is available or the difference between the sampling train pressure gauge and vessel pressure gauge readings is greater than +/- 5 psig, the sampling train pressure gauge reading shall be used to record the pressure on Form 1.

3.15 “Operating temperature” means the temperature of the vessel from which a sample is collected. If no vessel temperature gauge is available or the difference between the sampling train temperature gauge reading and the vessel temperature gauge reading is greater than +/- 4 ^{o}F, then the sampling train temperature gauge reading shall be used to record the temperature on Form 1.

3.16 "Portable pressurized separator" means a sealed vessel that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled and is used for separating and sampling crude oil, condensate, or produced water at the temperature and pressure of the separator and tank system required for sampling.

3.17 "Pressure separator" means a pressure vessel used for the primary purpose of separating crude oil and produced water or for separating natural gas and produced water.

3.18 “Pressure vessel” means any vessel rated, as indicated by an ASME pressure rating stamp, and operated to contain normal working pressures of at least 15 psig without vapor loss to the atmosphere and may be used for the separation of crude oil, condensate, produced water, or natural gas.

3.19 “Produced water” means water recovered from an underground reservoir as a result of crude oil, condensate, or natural gas production and which may be recycled, disposed, or re-injected into an underground reservoir.

3.20 “Separator” means any tank or pressure separator used for the primary purpose of separating crude oil and produced water or for separating natural gas, condensate, and produced water. In crude oil production a separator may be referred to as a Wash Tank or as a three-phase separator. In natural gas production a separator may be referred to as a heater/separator.

3.21 "Separator and tank system" means the first separator in a crude oil or natural gas production system and any tank or sump connected directly to the first separator.

3.22 "Tank" means any container constructed primarily of non-earthen materials used for the purpose of storing, holding, or separating emulsion, crude oil, condensate, or produced water and that is designed to operate below 15 psig normal operating pressure.

3.23 "Target temperature" means the temperature at which a pressurized hydrocarbon liquid is flashed, and is therefore the temperature of the first atmospheric separator or tank.

3.24 "Throughput" means the average volume of crude oil, condensate, or produced water expressed in units of barrels per day.

4. BIASES AND INTERFERENCES

4.1 The sampling method used to collect a liquid sample will have an impact on the final results reported. Liquid samples shall be collected in accordance with the sampling procedures specified in this procedure.

4.2 The location from where a sample is collected will have an impact on the final results reported. Liquid samples shall be collected from a pressure separator or portable pressurized separator as specified in this procedure.

4.3 Collecting liquid samples from a pressure separator or portable pressurized separator that periodically drains liquids will have an impact on the final results reported. Samples shall not be collected from a pressure separator or portable pressurized separator while it periodically drains liquids and shall only be taken when a drain valve is closed.

4.4 Collecting liquid samples using an empty double valve cylinder will allow gases to flash from the cylinder and will have an impact on the final results reported. Samples collected using a double valve cylinder shall be collected as specified in this procedure.

4.5 Displacing liquids from a double valve cylinder that are reactive and not immiscible with the sample liquid collected will result in gas composition or volume errors and will affect the final results reported. Displacement liquids shall be pre-tested by a laboratory to verify that the liquid is non-reactive and is immiscible with the sample liquid collected.

4.6 Non-calibrated equipment including pressure or temperature gauges will have an impact the final results reported. All pressure and temperature measurements shall be conducted with calibrated gauges as specified in this procedure and shall be calibrated at least twice per year.

4.7 Conducting laboratory procedures other than those specified in this procedure will have an impact on the final results reported. All laboratory methods and quality control and quality assurance procedures shall be conducted as specified in this procedure.

4.8 The collection of duplicate samples is recommended to verify reported results.

4.9 Failure to perform the bubble point pressure and sample integrity check may affect the reported results.

4.10 Performing a flash analysis by a means other than the method specified in this procedure may affect the reported results.

5. SAMPLING EQUIPMENT SPECIFICATIONS

5.1 An intrinsically safe pressure gauge capable of measuring liquid pressures of up to 2,000 pounds per square inch absolute within +/- 0.1 percent accuracy.

5.2 A temperature gauge capable of reading liquid temperature within +/- 2^{o}F and within a range of 32^{o}F to 250^{o}F.

5.3 A graduated cylinder capable of measuring liquid in at least five (5) milliliter increments with at least the same capacity as the double valve cylinder used for liquid sampling.

5.4 A portable pressurized separator that is sealed from the atmosphere and is used for collecting crude oil, condensate, and produced water samples at the temperature and pressure of the separator and tank system being sampled.

6. SAMPLING EQUIPMENT

6.1 A double valve cylinder or a piston cylinder of at least 300 milliliters in volume for collecting crude oil or condensate samples or at least 800 milliliters in volume for collecting produced water samples.

6.2 A graduated cylinder for use with double valve cylinder.

6.3 A waste container suitable for capturing and disposing sample liquid.

6.4 High-pressure rated metal components and control valves that can withstand the temperature and pressure of the pressure separator from which sample liquid is gathered.

6.5 Pressure gauge~~s~~ with minimum specifications listed in Section 5.

6.6 Temperature gauge with minimum specifications listed in Section 5.

6.7 If required, a portable pressurized separator with minimum specifications listed in Section 5.

7. DATA REQUIREMENTS

7.1 The data required to conduct this procedure shall be provided by the facility owner or operator prior to conducting the sampling methods specified in this procedure. Field sampling shall not be performed until all data requirements are provided as listed in Section 7.2 and as specified on Form 1.

7.2 For each sample collected, the following data shall be recorded on the sample cylinder identification tag and on Form 1 prior to conducting a sample collection method:

(a) The separator identification number or description.

(b) The separator temperature and pressure if available.

(c) First downstream atmospheric tank or separator temperature.

8. DOUBLE VALVE CYLINDER SAMPLING METHOD

8.1 Fill the double valve cylinder with non-reactive liquid that is immiscible with the liquid to be collected to prevent flashing within the cylinder and to prevent the displacement liquid from mixing or attaining homogeneity with the sample liquid.

(a) As an alternative for collecting produced water samples, the double valve cylinder may be filled with sample water under the same pressure as the vessel to be sampled and then purged according to the procedure specified in section 8.6.

8.2 Identify a pressure separator immediately upstream of the separator or tank required for testing. If no pressure separator is available, install a portable pressurized separator immediately upstream of the separator or tank that can be used to collect crude oil, condensate, and produced water samples.

8.3 Record the sample collection data requirements specified in Section 7 on the cylinder identification tag and on Form 1.

8.4 Locate the sampling port(s) for collecting liquid samples.

8.5 Connect the sampling train as illustrated in Figure 1 to the sampling port on the pressure separator or portable pressurized separator while minimizing tubing between the purge valve and cylinder as shown. Bushings or reducers may be required.

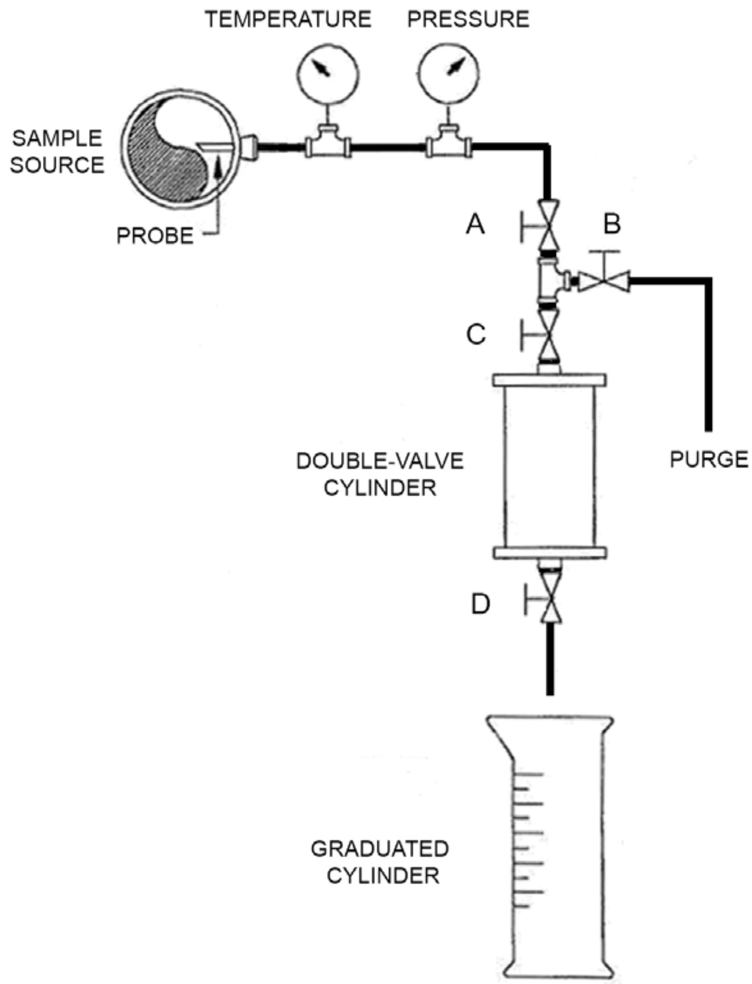
8.6 Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.

8.7 Prepare for sampling: Orient the double-valve cylinder in the vertical position so that displacement liquid can readily be discharged from the cylinder. Note that the orientation of valves C and D depend on the type of sample being collected and the liquid used for displacement. Based on density differences in liquids, the heaviest liquid must be introduced or expelled from the bottom of cylinder. See Figure 2.

(a) If the alternative method for collecting a produced water sample is chosen, the cylinder must be purged at a rate not to exceed 60 milliliters per minute until at least 1600 milliliters (two cylinder volumes) are purged through the cylinder that has been previously filled with pressurized sample water prior to proceeding further.

8.8 Slowly open valve C to the full open position and place the outlet of valve D into the graduated cylinder.

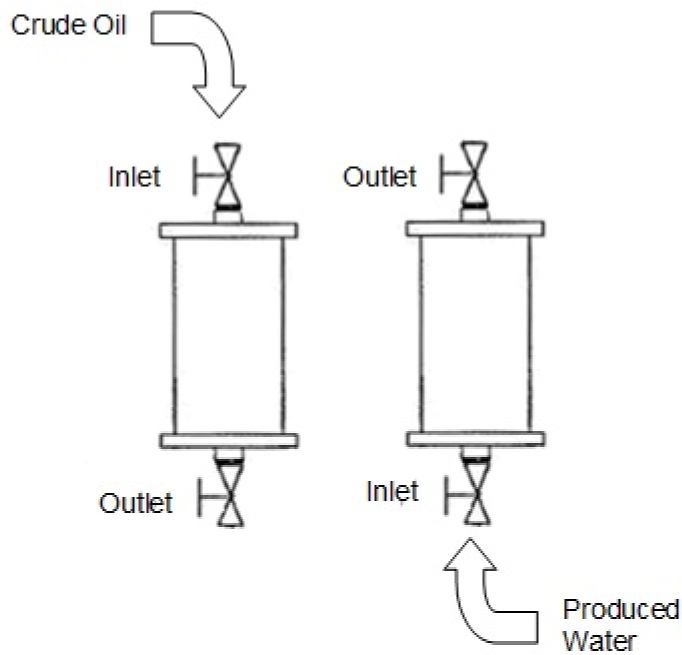
Figure 1: Double Valve Cylinder Sampling Train



8.9 Collect liquid sample: Slowly open valve D to allow a slow displacement of the non-reactive displacement liquid at a rate not to exceed 60 milliliters per minute to prevent the sample liquid from flashing. Continue until approximately 70 percent of the displacement liquid is measured in the graduated cylinder. Then close valves D and C.

8.10 Record the pressure and temperature on Form 1.

Figure 2: Double Valve Cylinder Orientation



8.11 Record the double valve cylinder volume and the volume of liquid sampled on the cylinder identification tag and on Form 1.

8.12 Drain approximately 20 percent of the remaining displacement liquid into the graduated cylinder to take outage and record the actual volume of liquid drained on Form 1. This is required for safety and to prevent a pressurized cylinder from exploding during transport.

8.13 Disconnect the sample cylinder from the sampling train and verify that both valves are sealed.

8.14 Remove sampling train: With valves D and C closed, purge any remaining liquid in the sampling train through valve B. Then close valves A and B. Disconnect the sampling train from the pressure separator or portable pressurized separator.

8.15 Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.

8.16 Transport the cylinder to the laboratory for conducting the laboratory methods specified in Section 12.

9. PISTON CYLINDER SAMPLING METHOD

9.1 Identify a pressure separator immediately upstream of the separator or tank required for testing. If no pressure separator is available, install a portable pressurized separator immediately upstream of the separator or tank that can be used to collect crude oil, condensate, and produced water samples.

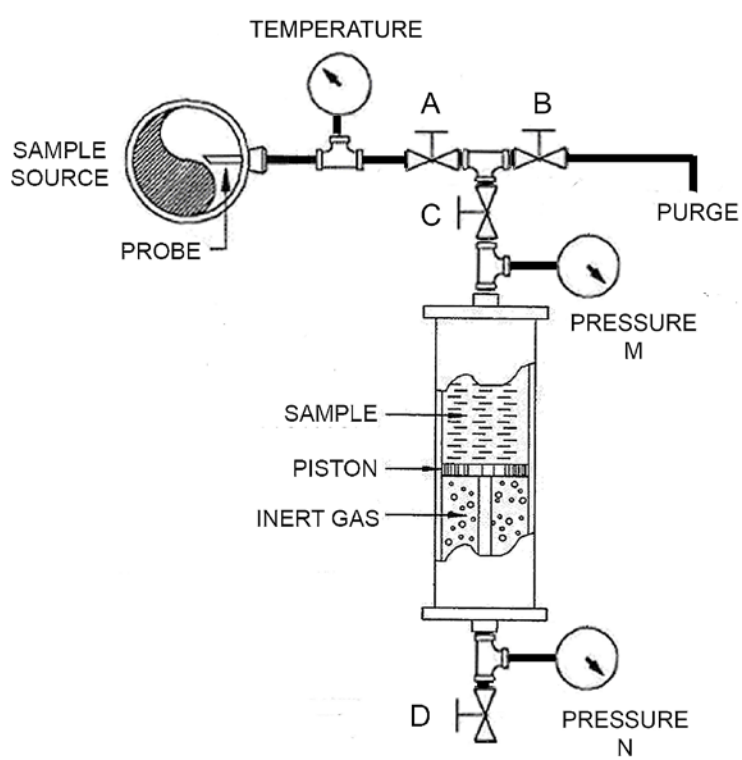
9.2 Record the sample collection data requirements specified in Section 7 on the cylinder identification tag and on Form 1.

9.3 Locate the sampling port(s) for collecting liquid samples.

9.4 Connect the sampling train as illustrated in Figure 3 to the pressure separator or pressurized portable separator while minimizing tubing between the purge valve and cylinder as shown. Bushings or reducers may be required.

9.5 Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.

Figure 3: Piston Cylinder Sampling Train



9.6 Prepare for sampling: Verify that the gas pressure in the piston cylinder is greater than the pressure of sample liquid. If not, additional gas pressure must be applied to the piston.

9.7 With valve B closed and valve A open, slowly open valve C to the full open position, then slowly open valve D until the pressure indicated on Gauge N is equal to Gauge M and then close valve D momentarily.

9.8 Collect liquid sample: Slowly open Valve D to allow liquid to enter the piston cylinder at a rate not to exceed 60 milliliters per minute by using the indicator and scale on the piston cylinder. Continue until a maximum of 80 percent of the cylinder is filled with liquid. Then close valves C and D.

9.9 Record the pressure and temperature on Form 1.

9.10 Record the cylinder volume and volume of liquid sampled on the cylinder identification tag and on Form 1.

9.11 Disconnect the sample cylinder from the sampling train and verify that both valves are sealed.

9.12 Remove sampling train: Place the outlet of valve B into the waste container and slowly open valve B to purge all liquid from the sampling train. Then close valves A and B. Disconnect the sampling train from the pressure separator or portable pressurized separator.

9.13 Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.

9.14 Transport the cylinder to the laboratory for conducting the laboratory methods as specified in Section 12.

10. LABORATORY REQUIREMENTS AND METHODS

10.1 Quality Control, Quality Assurance, and Field Records

(a) Quality control requirements shall be performed in accordance with the laboratory methods specified in this test procedure.

(b) Each day of sampling, at least one field duplicate sample shall be collected per matrix type (crude oil, condensate, produced water). The field duplicate samples are collected to demonstrate acceptable method precision. Through this process the laboratory can evaluate the consistency of sample collection and analytical measurements as well as matrix variation. The laboratory should establish control limits based on relative percent difference to evaluate the validity of the measured results.

(c) Laboratory procedures shall be in place for establishing acceptance criteria for field activities described in Sections 7, 8 and 9 of this procedure. All deviations from the acceptance criteria shall be documented. Deviations from the acceptance criteria may or may not affect data quality.

(d) Laboratory procedures shall be in place to ensure that field staff have been trained on the sampling methods specified in this procedure and retrained on sampling methods if this procedure changes.

(e) Field records shall provide direct evidence and support necessary for technical interpretations, judgments, and discussions concerning project activities and shall, at a minimum, include a completed copy of Form 1 as provided in this procedure for each sample collected.

10.2 Laboratory Equipment

(a) All laboratory equipment used to conduct measurements shall be calibrated in accordance with the manufacturer specifications and in accordance with the laboratory methods specified in this procedure.

(b) Any chromatograph system that allows for the collection, storage, interpretation, adjustment, or quantification of chromatograph detector output signals representing relative component concentrations may be used to conduct this procedure. All test methods and quality control requirements shall be conducted in accordance with each laboratory method specified.

(c) The minimum reporting limit of the instruments used for reporting gaseous compounds must be at least 100 parts per million (ppm) for both hydrocarbon and fixed gases.

(d) The laboratory equipment, including sample lines, must be temperature controlled and allow for the independent control of the sample cylinder and flash analysis equipment temperatures.

(e) A gas volume meter with the capability of measuring volume in increments of one (1) milliliter minimum is required.

(f) Laboratory vessels (e.g., glassware, cylinders, etc.) and equipment for collecting flash gas without sample degradation and without compromising the integrity of the sample are required.

(g) A metering pump for introducing deionized water into a sample cylinder that can meter the water in precise increments (e.g., 0.01 milliliters) is required.

(h) Additional sample preparation guidance can be found in GPA Standard 2174-93, GPA Standard 2261-00 and GPA Standard 2177-03.

10.3 Bubble Point Pressure and Sample Integrity Check

This procedure is used to determine the bubble point pressure at sample collection temperature of a pressurized hydrocarbon liquid prior to conducting a flash or any compositional analysis. These results determine the integrity of the sample and provide a means of verifying the sampling conditions reported on Form 1. When heating is required, safety precautions must be taken due to thermal expansion within a pressurized cylinder. This procedure is performed with the use of a Double Valve cylinder and is not applicable for Floating-Piston cylinders. Samples gathered with the use of a Floating-Piston cylinder must be transferred to a Double Valve cylinder using a water displacement method prior to conducting this procedure.

(a) Fix the cylinder in an upright vertical position using a ring stand or similar device. This ensures that headspace gas remains at the top of the cylinder.

(b) Connect a pressure gauge and source of pressurized deionized water to the bottom of the sample cylinder using a metering pump for measuring the volume of water introduced into the sample cylinder.

(c) Slowly condition the cylinder to the measured sample collection temperature reported on Form 1 while monitoring pressure for a minimum of two (2) hours or until a change of no more than one (1) psi in pressure over 15 minutes is observed.

(d) Introduce deionized water while slowly mixing the sample by tilting the cylinder no more than 60 degrees from vertical in either direction to ensure that headspace gas remains at the top of the cylinder and liquid remains on the bottom. Continue adding deionized water to increase the pressure to above the pressure reported on Form 1, while mixing to ensure the sample returns to a single phase liquid.

(e) Record the stabilized pressure reading on the laboratory report.

(f) Remove a small increment of deionized water (approximately 0.5 milliliters) to reduce the pressure and allow it to stabilize. Document the sample pressure and the volume of deionized water (pump volume) on the laboratory report. Repeat until at least three (3) pressure readings above and three (3) pressure readings below the reported value on Form 1 are gathered.

(g) Graph the results of sample pressure and volume of deionized water (pump volume). Draw a line between the points above the measured value on Form 1. Draw a second line between the points below the measured value on Form 1. The intercept of the two lines denotes the bubble point pressure.

(h) Record the bubble point pressure on the laboratory report.

(i) Any sample that fails to achieve the following Pass/Fail criteria, which is the percentage difference between the bubble point pressure and the sample collection pressure reported on Form 1, shall be discarded:

Pass/Fail Criteria for Bubble Point Pressure Measurements
+/- 5% for > 500 psig +/- 7% for 250 - 499 psig +/- 10% for 100 - 249 psig +/- 15% for 50 - 99 psig +/- 20% for 20 - 49 psig +/- 30% for < 20 psig

10.4 Laboratory Flash Analysis Procedure

This procedure is used to determine the volume and composition of gas flashed from a pressurized liquid. This procedure is conducted after performing the bubble point pressure measurement to verify sample integrity.

(a) Condition the sample cylinder to the collection temperature recorded on Form 1 for a minimum of two (2) hours. This step may be expedited by performing in conjunction with the Bubble Point determination.

(b) Connect a pressure gauge and source of pressurized deionized water to the bottom of the sample cylinder using a metering pump for measuring the volume of water introduced into the sample cylinder.

(c) Connect the top of the sample cylinder to a temperature controlled flash chamber that can be heated or cooled independently from the sample cylinder. The chamber shall be of sufficient volume to allow for the flash process and the collection of the flashed liquid. Located at the top of the chamber will be an inlet for the liquid, and an outlet for the gas. The gas vent line will allow the flash gas to be routed through a constant volume gas cylinder and on to a gas meter (e.g., gasometer).

(d) Throughout the flash process, maintain the transfer lines, flash chamber, and constant volume gas cylinder and gas meter at the target temperature.

(e) Before introducing pressurized liquid into the flash chamber, evacuate the entire system and purge with helium. Vent the helium purge gas to atmosphere through the meter and then re-zero the gas meter.

(f) Introduce deionized water into the bottom of the liquid sample cylinder to increase the pressure to a start pressure above the bubble point pressure. This step ensures that the sample remains single phase when introduced into the flash chamber.

(g) Document the start pressure. The flash study will be performed at this pressure and not at the field recorded sample pressure.

(h) Partially open (*crack-open*) the liquid sample inlet valve to allow for a slight drip of liquid into the flash chamber. It is critical to maintain the pressurized liquid as close as possible to the start pressure.

(i) After liquid hydrocarbon and gas have been observed, terminate the flash procedure by closing the liquid inlet valve. Document the volume and/or weight of the residual liquid and the volume of gas collected. Document the volume of pressurized liquid sample introduced into the system.

(j) Isolate the gas sample in the constant volume gas cylinder by closing both valves. Detach the cylinder and analyze via GPA Standard 2286-95. Before analyzing, condition the gas sample for a minimum of two hours at a temperature of at least 30°F above the target temperature. Assure that the GC inlet line is heat traced to maintain sample integrity upon injection.

(k) Measure the pressurized liquid density at the start pressure and temperature. Also measure the density at a second pressure also above the bubble point pressure and the start pressure. Extrapolate the density of the pressurized liquid at the collection pressure recorded on Form 1.

(l) Correct the pressurized liquid volume from the start pressure to the sample collection pressure recorded on Form 1 using the density measurements.

(m) Document corrected liquid volume.

(n) Perform all necessary calculations including that of the GOR or GWR.

(o) A mass balance (analytical integrity check) may be performed by comparing the weight of pressurized liquid used for the flash (determined from the corrected volume used and the density at sample conditions) to the sum of the weight of the liquid and the weight of the gas.

10.5 Gas-Oil and Gas-Water Ratio Calculation Methodology

(a) Convert the volume of gas vapor measured during the laboratory flash analysis procedure to standard atmospheric conditions as derived from the Ideal Gas Law as follows:

$$Vapor_{Std} = \frac{(Volume_{Lab})(459.67 + 60F)(P_{Lab})}{(459.67 + T_{Lab})(14.696)}$$ **Equation 1**

Where:
Vapor $_{Std}$ = Standard cubic feet of vapor at 60°F and 14.696 psia.
Volume $_{Lab}$ = Volume of vapor measured at laboratory conditions.
T_{Lab} = Temperature of vapor at laboratory conditions, °F.
P_{Lab} = Pressure of vapor at laboratory conditions, psia.
459.67 = Conversion from Fahrenheit to Rankine
60F = Standard temperature of 60°F.
14.696 = Standard atmospheric pressure, psia.

(b) Convert the volume of crude oil, condensate, or produced water measured after conducting the laboratory flash analysis procedure to standard conditions as follows:

$$Liquid_{Std} = \left(\frac{Mass_{Liquid}}{Density_{60F}}\right)\left(\frac{1\ gallon}{3785.412\ ml}\right)\left(\frac{1\ STB}{42\ gallons}\right)$$ **Equation 2**

Where:
Liquid $_{Std}$ = Standard volume of post-flash liquid at 60°F, barrels.
Mass $_{Liquid}$ = Mass of liquid at laboratory conditions, grams.
Density $_{60F}$ = Density of liquid at 60°F, grams/milliliter.
3785.412 = Conversion from milliliter to US gallons.
STB = Stock Tank Barrel.
42 gallons = Volume of a stock tank barrel at 60°F.

(c) Calculate the Gas-Oil or Gas-Water Ratio as follows:

$$G = \frac{(Vapor_{Std})}{(Liquid_{Std})}$$ **Equation 3**

Where:
G = The Gas-Oil or Gas-Water Ratio.
Vapor $_{Std}$ = Standard cubic feet of vapor at 60°F and 14.696 psia.
Liquid $_{Std}$ = Standard volume of post-flash liquid at 60°F, barrels.

10.6 Analytical Laboratory Methods and Requirements

The following methods are required to evaluate and report flash emission rates from crude oil, condensate, and produced water.

(a) Oxygen, Nitrogen, Carbon Dioxide, Methane, Ethane, Propane, i-Butane, n-

Butane, i-Pentane, n-Pentane, Hexanes, Heptanes, Octanes, Nonanes, Decanes+: Evaluate per GPA Standard 2286-95, ASTM D1945-03, and ASTM D 3588-98.

(b) BTEX: Evaluate per US EPA Method 8021B (GC/FID) or use ASTM D7096-16, GPA Standard 2286-95, US EPA Method 8260B, US EPA Method TO-14A, and US EPA Method TO-15 as alternate methods.

(c) API Gravity of whole oil at 60ºF by ASTM D 287-92 (Hydrometer Method), ASTM D4052-09 (Densitometer), ASTM D5002-16 (Densitometer), or ASTM D70-09 (Pycnometer). Note: if water is entrained in sample, use ASTM D 287-92. If needed calculate Specific Gravity 60/60ºF = 141.5 / (131.5 + API Gravity at 60ºF)

(d) Specific Gravity of Produced Water at 60ºF by ASTM D 287-92 (Hydrometer Method), ASTM D4052-09 (Densitometer), ASTM D5002-16 (Densitometer), or ASTM D70-09 (Pycnometer). If needed calculate API at 60ºF = (141.5 / SG at 60ºF) - 131.5.

(e) Molecular Weight of gaseous phase by calculation per ASTM D 3588-98.

11. CALCULATING RESULTS

The following calculations are performed by the owner or operator in conjunction with the laboratory reports specified in Section 12. The same calculations are used for crude oil, condensate, and produced water.

11.1 Calculate the volume of gas flashed from the liquid per year using the Gas Oil or Gas Water Ratio obtained from the laboratory report as follows:

$$Ft^3 / Year = (G)\left(\frac{Barrels}{Day}\right)\left(\frac{Days}{Year}\right)$$

Equation 4

<u>Where:</u>
Ft^3/Year = standard cubic feet of gas produced per year
G = Gas Oil or Gas Water Ratio (from laboratory report)
Barrels/Day = barrels per day of liquid (DOGGR certified reports)
Days/Year = days of operation per year (owner/operator)

11.2 Convert the gas volume to pounds as follows: **Equation 5**

$$Mass_{Gas} / Year = \left(\frac{Ft^3}{Year}\right)\left(\frac{gram}{gram-mole}\right)\left(\frac{gram-mole}{23.690\, l}\right)\left(\frac{28.317\, l}{Ft^3}\right)\left(\frac{lb}{454 grams}\right)$$

Where:
Mass $_{Gas}$ /Year = pounds of gas per year
Ft^3/Year = cubic feet of gas produced per year (Equation 1)
Gram/Gram-Mole = Molecular weight (from laboratory report)
23.690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60^{0}F

11.3 Calculate the annual mass of methane as follows:

$$Mass_{Methane}/Year = \left(\frac{WT\%\,Methane}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{metric\ ton}{2205\ lb}\right)$$ **Equation 6**

Where:
Mass $_{Methane}$ /Year = metric tons of methane
Mass $_{Gas}$ /Year = pounds of gas per year (Equation 5)
WT% Methane = Weight percent of methane (from laboratory report)

12. LABORATORY REPORTS

12.1 The results of this procedure are used by owners or operators of separator and tank systems to report annual methane flash emissions to ARB. The following information shall be compiled as a report by the laboratory conducting this procedure and provided to the owner or operator each time flash analysis testing is conducted:

(a) A sketch or diagram of the separator and tank system depicting the sampling location; and,

(b) A copy of Form 1 as specified in this procedure for each liquid sample collected; and,

(c) The laboratory results for each liquid sample evaluated as specified in Section 12.4; and,

(d) Other documentation or information necessary to support technical interpretations, judgments, and discussions.

12.2 Reports shall be made available to the owner or operator no later than 60 days from the date of liquid sampling.

12.3 Reports shall be maintained by the laboratory conducting this procedure for a minimum of five (5) years from the date of liquid sampling and additional copies shall be made available at the request of the owner or operator.

12.4 Laboratory reports shall include, at minimum, a listing of results obtained using the laboratory methods specified in this procedure and as specified in Table 1.

Table 1: Laboratory Data Requirements

WT% CO_2, CH_4
WT% C2-C9, C10+
WT% BTEX
WT% O2
WT% N2
Molecular Weight of gas sample (gram/gram-mole)
Liquid phase specific gravity of produced water
Gas Oil or Gas Water Ratio (scf/stock tank barrel)
API gravity of whole oil or condensate at 60ºF
Post-Test Cylinder Water Volume
Post-Test Cylinder Oil Volume

13. ALTERNATIVE TEST PROCEDURES, SAMPLING METHODS OR LABORATORY METHODS

Alternative test procedures, sampling methods, or laboratory methods other than those specified in this procedure shall only be used if prior written approval is obtained from ARB. In order to secure ARB approval of an alternative test procedure, sampling method, or laboratory method, the applicant is responsible for demonstrating to the ARB's satisfaction that the alternative test procedure, sampling method, or laboratory method is equivalent to those specified in this test procedure.

13.1 Such approval shall be granted on a case-by-case basis only. Because of the evolving nature of technology and procedures and methods, such approval shall not be granted in subsequent cases without a new request for approval and a new demonstration of equivalency.

13.2 Documentation of any such approvals, demonstrations, and approvals shall be maintained in the ARB files and shall be made available upon request.

14. REFERENCES

ASTM D70-09 *Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method), which is incorporated herein by reference. 2009.*

ASTM D 287-92 *Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), which is incorporated herein by reference. Reapproved 2000.*

ASTM D1945-03 *Standard Test Method for Analysis of Natural Gas by Gas Chromatography, which is incorporated herein by reference. Reapproved 2010.*

ASTM D 3588-98 *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, which is incorporated herein by reference. Reapproved 2003.*

ASTM D4052-09 *Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter, which is incorporated herein by reference. 2009.*

ASTM D5002-16 *Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer, which is incorporated herein by reference. 2016.*

ASTM D7096-16 *Standard Test Method for Determination of the Boiling Point Range Distribution of Gasoline by Wide Bore Capillary Gas Chromatography, which is incorporated herein by reference. 2016.*

US EPA Method 8021B *Aromatic and Halogenated Volatiles by Gas Chromatography Using Photoionization and/or Electrolytic Conductivity Detectors, which is incorporated herein by reference. 2014.*

US EPA Method 8260B *Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), which is incorporated herein by reference. 1996.*

US EPA Method TO-14A *Determination of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters with Subsequent Analysis By Gas Chromatography, which is incorporated herein by reference. 1999.*

US EPA Method TO-15 *Determination of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters and Analyzed By Gas*

Chromatography/Mass Spectrometry (GC/MS), which is incorporated herein by reference. 1999.

GPA Standard 2174-93 *Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, which is incorporated herein by reference. 2000.*

GPA Standard 2177-03 *Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, which is incorporated herein by reference. 2003.*

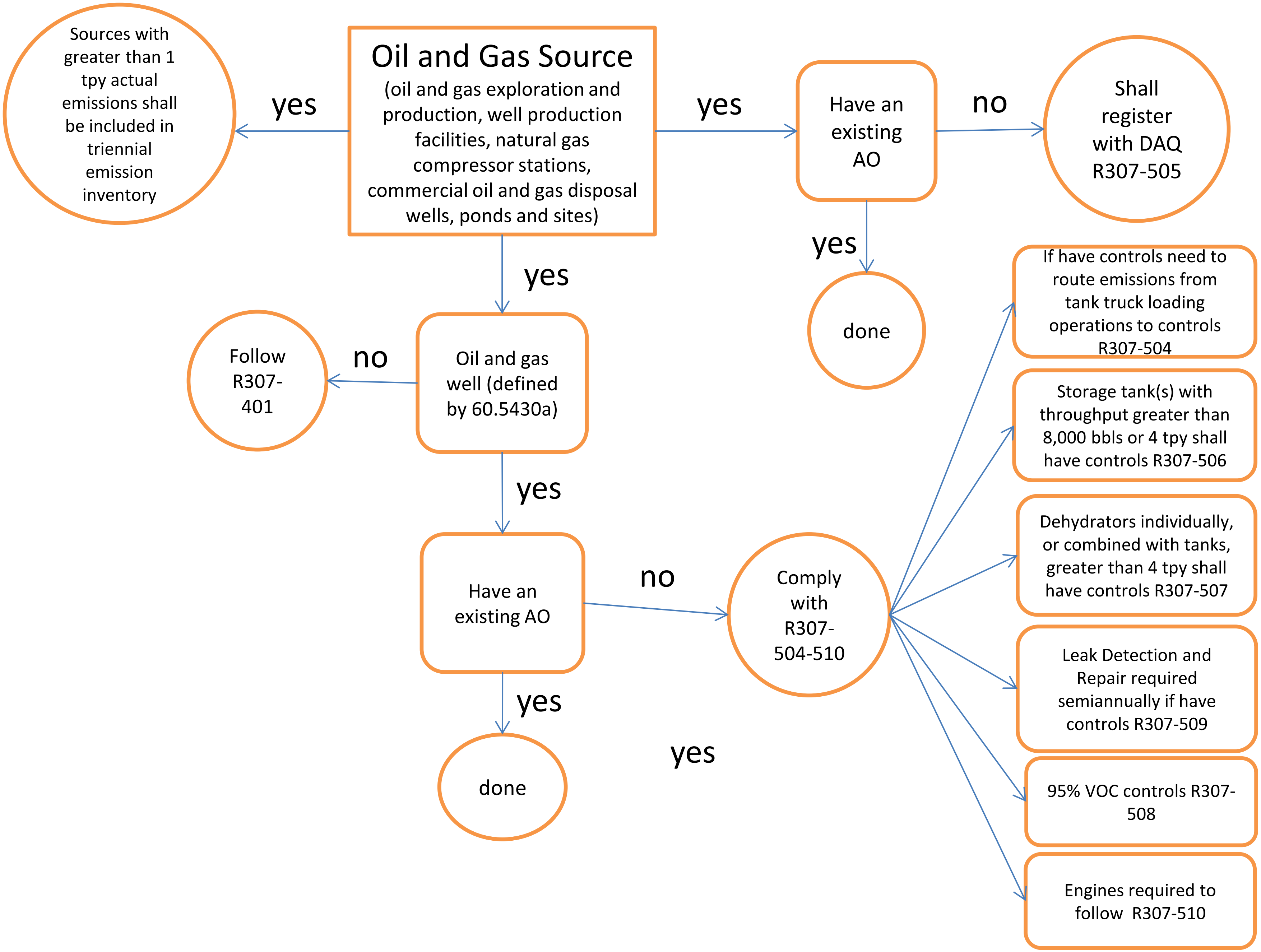
GPA Standard 2261-00 *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, which is incorporated herein by reference. 2000.*

GPA Standard 2286-95 *Tentative Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography, which is incorporated herein by reference. Reprinted 1999.*

FORM 1
Flash Analysis Testing Field Data Form

Date of Testing:	
Production Company Name:	
Address:	
City:	
Contact:	Phone:
Sampling Company Name:	
Address:	
City:	
Contact:	Phone:
Sample Information	
Portable Pressure Separator ID:	
Pressure Separator ID:	
Sample Pressure: psia	
Sample Temperature: ºF	
Atmospheric Tank or Separator Temperature ºF	
Cylinder Type (Double Valve or Piston):	
Sample Type (circle one): crude oil condensate produced water	
Cylinder ID:	Cylinder Volume: ml
Displacement Liquid:	
Sample Volume: ml	Outage Displaced: ml

APPENDIX H


Oil and Gas Source
(oil and gas exploration and production, well production facilities, natural gas compressor stations, commercial oil and gas disposal wells, ponds and sites)
yes
Sources with greater than 1 tpy actual emissions shall be included in triennial emission inventory
yes
Have an existing AO
no
Shall register with DAQ R307-505
yes
done
yes
Oil and gas well (defined by 60.5430a)
no
Follow R307-401
yes
Have an existing AO
no
Comply with R307-504-510
yes
done
yes
If have controls need to route emissions from tank truck loading operations to controls R307-504
Storage tank(s) with throughput greater than 8,000 bbls or 4 tpy shall have controls R307-506
Dehydrators individually, or combined with tanks, greater than 4 tpy shall have controls R307-507
Leak Detection and Repair required semiannually if have controls R307-509
95% VOC controls R307-508
Engines required to follow R307-510

APPENDIX I

Colorado Air Quality Control Commission's
2017 Revisions to Regulation Number 7 – Oil and Gas Emissions
Fact Sheet

Rulemaking Summary:

On November 16, 2017, Colorado's Air Quality Control Commission ("Commission") strengthened existing oil and gas control measures in Regulation Number 7 to comply with federal requirements and improve ozone levels. This rulemaking was largely driven by Colorado's obligation under the federal Clean Air Act to include provisions implementing reasonably available control technology ("RACT") requirements in Colorado's Ozone State Implementation Plan ("SIP") for the categories of sources addressed in EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG").[1] The revisions include requirements for compressors, pneumatic controllers, pneumatic pumps, equipment leaks at natural gas processing plants, and fugitive emissions at well production facilities and natural gas compressor stations located in the Denver Metro North Front Range ("DMNFR") ozone nonattainment area ("NAA") in Colorado's Ozone SIP. The Commission determined that existing storage tank requirements in Colorado's Ozone SIP (Section XII.) were sufficient to address recommendations in the Oil and Gas CTG.

The Commission also adopted state only measures that go beyond recommendations in the Oil and Gas CTG that are intended to further expedite the attainment of ozone standards. The Commission established inspection requirements for natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the DMNFR NAA. The revisions also include other supporting, corresponding, and clarifying revisions to some existing, statewide provisions.[2]

Discussion of Revisions:

Regulation Number 7, Sections XII., XVII., and XVIII.

To address the Oil and Gas CTG, the Commission relied in large part on existing requirements in Regulation Number 7 for the oil and gas sector. The Commission strengthened existing requirements and adopted new requirements consistent with the Oil and Gas CTG model rule where necessary. Most of the rule changes are slated to become federally enforceable through Colorado's Ozone SIP and will apply only in the DMNFR NAA (Section XII. and part of Section XVIII.), while some rule changes are state only and may apply statewide (Section XVII. and part of Section XVIII.). The changes apply to new and existing sources.

Equipment Leaks at Natural Gas Processing Plants (Section XII.G.) (SIP, DMNFR NAA)

- Beginning January 1, 2019, the revisions require that owners or operators of natural gas processing plants comply with the leak detection and repair ("LDAR") program in NSPS OOOO, unless subject to the LDAR program in NSPS OOOOa.
    - The revisions expand upon the existing requirement to comply with the LDAR program in the older NSPS KKK, or applicable LDAR provisions in NSPS OOOO or OOOOa. The LDAR programs in NSPS OOOO and OOOOa apply lower leak thresholds for responsive action than in NSPS KKK.

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[1] EPA submitted to the Office of Management and Budget a request for comment on potentially withdrawing the Oil and Gas CTG in December 2017. EPA's rule agenda projects publication of this notice in January 2018. Regardless of the outcome of EPA's action on the Oil and Gas CTG, the Regulation Number 7 revisions are effective December 30, 2017.

[2] The pneumatic controller inspection program in Section XVIII.F. and revisions to existing, statewide provisions are adopted on a State Only basis; thus are not included in Colorado's Ozone SIP or federally enforceable.

Colorado Air Quality Control Commission's
2017 Revisions to Regulation Number 7 – Oil and Gas Emissions
Fact Sheet

Compressors (Section XII.J.) (SIP, DMNFR NAA)

- Beginning January 1, 2018, the revisions require that owners or operators of wet seal centrifugal compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment, but not at a well production facility, reduce VOC emissions by at least 95%.
    - The revisions expand upon the existing requirement to reduce hydrocarbon emissions from wet seal centrifugal compressors by 95% in Section XVII.B.3.b. by adding monitoring and recordkeeping requirements.
- Beginning January 1, 2018, the revisions require that owners or operators of reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment, but not at a well production facility, periodically replace rod packing or route rod packing emissions to a process.
    - The revisions expand upon the existing rod packing replacement requirement in Section XVII.B.3.c. by applying to reciprocating compressors at natural gas processing plants, adding the option to route emissions to a process, and adding monitoring and recordkeeping requirements.
- The revisions require that owners or operators routing emissions to a control device or a process conduct annual visual and Method 21 inspections and repair defects or leaks.
- The revisions require that owners or operators equip combustion devices with an auto-igniter (Section XII.C.1.e.(iv)) and inspect combustion devices monthly.
- The revisions require that owners or operators keep records of compressors, rod packing replacements, inspections, responsive actions, and inspection or repair delays.

Pneumatic Pumps (Section XII.K.) (SIP, DMNFR NAA)

- Beginning May 1, 2018, the revisions require that owners or operators of natural gas-driven diaphragm pneumatic pumps located at a natural gas processing plant have a VOC emission rate of zero and keep records of pumps.
- Beginning May 1, 2018, the revisions require that owners or operators of natural gas-driven diaphragm pneumatic pumps located at a well production facility reduce VOC emissions by 95% if it is technically feasible to route emissions to an existing control device or process.
    - The revisions require that owners or operators conduct annual visual and Method 21 inspections of the closed vent system and repair defects or leaks.
    - The revisions require that owners or operators equip combustion devices with an auto-igniter (Section XII.C.1.e.(iv)).
    - The revisions require that owners or operators keep records of pneumatic pumps, inspections, responsive actions, and inspection or repair delays.

LDAR (Section XII.L.) (SIP, DMNFR NAA)

- The revisions require owners or operators of some natural gas compressor stations and well production facilities to inspect components (e.g., valves, flanges, connectors, etc.) for leaks on a more frequent basis.
    - The revisions clarify that thief hatches and other openings on a controlled storage tank are "components" and must be included in LDAR inspections (Section XII.B.9.).

- Beginning June 30, 2018, owners or operators of natural gas compressor stations must inspect components for leaks on a quarterly basis.
- Beginning June 30, 2018, owners or operators of well production facilities with VOC emissions greater than or equal to one ton per year ("tpy") and less than or equal to six tpy must inspect components for leaks on an annual basis.
- Beginning June 30, 2018, owners or operators of well production facilities with VOC emissions greater than six tpy must inspect components for leaks on a semi-annual basis.
  - The revisions expand upon the existing LDAR requirements in Section XVII.F. by increasing the inspection frequencies for natural gas compressor stations and well production facilities with VOC emissions less than or equal to twelve tpy.
  - The revisions do not reduce the more frequent inspections required by the Section XVII.F. LDAR program.

- The revisions set thresholds for leaks requiring repair based on the method used to detect the leak. The repair threshold for leaks detected with an IR camera is any detectable emission. The repair threshold for leaks detected with EPA Reference Method 21 is 500 ppm hydrocarbons.
  - The revisions expand upon the existing leak repair thresholds in Section XVII.F. by requiring repair of leaks detected with Method 21 at all natural gas compressor stations if emissions exceed 500 ppm hydrocarbons.
- The revisions require a first attempt to repair within five days (unless parts are unavailable, shutdown is required, or for other good cause) and remonitoring within 15 days of repair.
  - The revisions expand upon existing repair requirements in Section XVII.F. by adding the requirement that repair be completed within thirty days after discovery and within two years after discovery if shutdown is required.
  - The revisions clarify that remonitoring of a repair must be conducted with an approved instrument monitoring method ("AIMM").
- The revisions require LDAR records be kept for five years, and made available to the Division.
  - The revisions expand upon existing recordkeeping requirements in Section XVII.F. by adding the requirement that owners or operators also keep records of the type of repair method applied, records of the review by an owner or operators' representative for delay of repair due to unavailable parts, the date and duration of delay of repair, and the schedule for repairing a leak on delayed repair. Owners or operators must keep records of 2018 LDAR activities to inform the 2019 annual report.
- The revisions require an annual LDAR report be submitted to the Division by May 31 of each year.
  - The revisions expand upon existing reporting requirements in Section XVII.F. by adding the requirement that owners or operators include the records of the reviews related to delay of repair due to unavailable parts and to report the total number of facilities inspected, the total number of inspections, the total number of leaks requiring repair, the total number of leaks repaired, and the delayed repair list by inspection frequency tier.
  - The first annual report containing the information required by the revisions is due May 31, 2019.
- The revisions allow a proponent to apply for approval of an alternative monitoring method or program to be used to comply with the Section XII.L. LDAR program.

   - The revisions expand upon existing approved instrument monitoring method requirements in Section XVII.F. by specifying how to apply for a determination of an alternative approved instrument monitoring method.

Storage Tanks (Section XVII.C.2.a.) (State Only, statewide)

- The revisions clarify that "venting" from storage tanks means emissions that are primarily the result of over-pressurization or that are the result of an open, unlatched, or visibly unseated pressure relief device, an open vent line, or an unintended opening in the storage tank.

LDAR (Section XVII.F.) (State Only, statewide)

- The revisions do not change the existing inspection frequencies in Section XVII.F., which in some cases are more stringent than the new inspection frequencies in Section XII.L.
- Beginning January 1, 2018, the revisions include the repair timeframe, recordkeeping, and reporting revisions described in the Section XII. LDAR provisions. The new recordkeeping elements must be kept of all 2018 LDAR activities to inform the 2019 annual report.

Pneumatic Controllers (Section XVIII.) (SIP, DMNFR NAA)

- The revisions include the existing low-bleed requirement for continuous bleed, natural gas-driven pneumatic controllers upstream of the natural gas processing plant in Colorado's Ozone SIP.
- The revisions require that continuous bleed, natural gas-driven pneumatic controllers at natural gas processing plants have a natural gas bleed rate of zero.
- Beginning January 1, 2018, the revisions require records of the estimated number of continuous bleed, natural gas-driven pneumatic controllers, and a periodic update of such estimate.

Pneumatic Controllers (Section XVIII.C.3.) (State Only, statewide)

- The revisions clarify the existing no-bleed pneumatic controller requirement and allow the use of self-contained pneumatic controllers in certain situations.

Pneumatic Controllers (Section XVIII.F.) (State Only, DMNFR NAA)

- Beginning June 30, 2018, the revisions require inspections of natural gas-driven pneumatic controllers to ensure proper operation. Where a pneumatic controller is determined not to be operating properly, owners or operators must take actions to return the pneumatic controller to proper operation. Owners or operators must also keep records of inspection and response activities and submit an annual report concerning such activities. The inspection frequencies, recordkeeping, and reporting requirements align with the LDAR provisions in Sections XII. and XVII.

Statement of Basis, Statutory Authority, and Purpose

- The Commission directed the Division to initiate a stakeholder process to evaluate cost-effective hydrocarbon emission reduction measures for the oil and gas sector statewide. The Division and stakeholder participants will brief the Commission on the stakeholder process in January 2019, and present recommendations to the Commission no later than January 2020.

- The Commission also directed the Division to initiate a study of pneumatic controller emission reduction options, including the causes of improper operation, inspection and repair techniques, preventative maintenance methods, and other related information. This task force will convene in January 2018, and data collection will begin no later than May 2018. The Division and task force participants will report findings to the Commission in May 2020.

For More Information:

Revisions to Regulation Number 7 (5 CCR 1001-9) are effective December 30, 2017, and are posted at: https://www.sos.state.co.us/CCR/Welcome.do and https://www.colorado.gov/pacific/cdphe/aqcc-regs

Unofficial regulatory text and related documents associated with the rulemaking hearing may be found at: https://www.colorado.gov/pacific/cdphe/aqcc

Implementation tools, guidance, and other compliance assistance tools are being developed or revised and will be posted on the Division's website at: http://www.colorado.gov/cdphe/airoilandgas

Finally, please submit questions or comments to: cdphe.commentsapcd@state.co.us