July 18, 2016
California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

Dear Air Resources Board:

Thank you for accepting these comments submitted by Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council and Sierra Club on Proposed Regulation Order 17 C.C.R. § 95665 et seq. (May 2016). We greatly appreciate the opportunity to comment on the California Air Resources Board's ("ARB") draft regulation for methane pollution from oil and gas facilities. These comments build upon recommendations that we submitted to ARB during its comprehensive stakeholder process and track closely recommendations that we made to ARB on the last draft, published February 19, 2016.[1]

I. Introduction

We commend the ARB on proposing one of the strongest rules in the nation to curb the release of harmful emissions from oil and gas facilities. The draft regulation contains cost effective, technically feasible mechanisms that will achieve critically needed reductions in methane, a potent climate-altering pollutant, as well as important co-benefit reductions in volatile organic compounds (VOCs) and air toxics that pose serious threats to human health. ARB staff estimates the proposal will cut methane emissions from the over 51,500 oil and gas facilities in the state[2] by half[3] while also removing 3,600 tons of VOCs and over 100 tons of air toxics from the atmosphere annually.[4]

Significant methane reductions are necessary for California to reach its goal of reducing greenhouse gas emissions to 1990 levels by 2020, as ARB acknowledges.[5] As ARB's Staff Report explains, such reductions "can have an immediate beneficial impact on climate change" due to the relatively short atmospheric life of methane.[6]

Requiring oil and gas owners and operators to capture rather than vent or leak methane emissions is one of the most cost- effective and sensible ways to achieve deep and immediate reductions in GHG emissions. Natural gas is primarily methane, and as ARB's draft proposal demonstrates, in many instances operators can benefit from the natural gas recovered either by sending it to sales or utilizing it onsite. Indeed, ARB's analysis demonstrates the proposal to be

[1] Clean Air Task Force, et al., "Methane comments to CARB" (February 19, 2016).
[2] ARB Staff Report: Initial Statement of Reasons, 6 (May 31, 2016), available at http://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20ISOR.pdf.
[3] *Id*. at ES-2.
[4] *Id.* at ES-4.
[5] ARB, Proposed Short-Lived Climate Pollutant Reduction Strategy, 13 (April 2016), available at http://www.arb.ca.gov/cc/shortlived/meetings/04112016/proposedstrategy.pdf
[6] *Id*. at 2.

highly cost effective at $15 per ton of CO2e reduced, considering savings.[7] Even without accounting for the savings operators can achieve by capturing methane, the draft rules are still highly cost effective at $17 per ton of CO2e reduced.[8] These numbers reflect only the direct benefits that accrue from the removal of 1.5 million metric tons of CO2e from the atmosphere annually. When one considers that the implementation of the various clean air measures contained in the proposal will remove additional tons of VOCs and air toxics annually, it is clear that this proposal represents a very cost effective pathway to achieve much-needed reductions in harmful oil and gas emissions.

Moreover, the state cannot rely on federal actions to achieve the greenhouse gas reductions required by legislative and gubernatorial mandates.[9] US EPA rules adopted to date under the New Source Performance Standards program do not apply to existing oil and gas sources,[10] and therefore will have no effect on the over 50,000 existing oil and gas wells in the state. While EPA has proposed requirements directed at reducing VOC emissions from a select number of onshore oil and gas facilities (control techniques guidelines, or CTGs),[11] these requirements are not final, and even once they become final, will have a limited effect on existing sources both in California and nationwide: the CTGs do not directly regulate methane, nor do they apply statewide (they only apply in parts of the state that are designated as moderate or above ozone nonattainment areas), and they do not apply to offshore facilities. Moreover, the proposed control techniques guidelines do not apply to many of the onshore facilities subject to the ARB proposal, including underground natural gas storage, transmission compressor stations, intermittent bleed pneumatic controllers or any facilities located in the storage and transmission segments. Accordingly, the proposed ARB rules are necessary to achieve critical reductions in methane, VOCs and air toxics that are left unaddressed by EPA requirements.

For all of the above reasons we urge ARB to adopt the Proposed Regulation Order, 17 C.C.R. § 95665 et seq. (May 2016). However, in so doing, we respectfully request ARB to strengthen the rule in a few key ways, the basis for which we discuss in the remainder of our comments:

- Leak detection and repair (LDAR)
    - Provide operators with flexibility to seek approval for utilizing alternative leak detection methods for making inspections provided such methods are at least as effective in reducing waste and emissions as Optical Gas Imaging (OGI)-based LDAR and that the approval process is transparent and open to public participation.

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[7] *Id*. at Table 14, 127.
[8] *Id*.
[9] Global Warming Solutions Act of 2006 (establishing statewide GHG emissions cap for 2020, based on 1990 emissions); *see also* ARB Senate Bill 605 (requiring ARB to develop a comprehensive plan to reduce emissions of short-lived climate pollutants); *see also* Short-Lived Climate Pollutant Reduction Strategy, supra note 5, discussing Governor Brown's announcement of a target for reducing GHG emissions to 40 percent below 1990 levels by 2030.
[10] *See* 81 Fed. Reg. 35,824 (June 3, 2016).
[11] *See* 80 Fed. Reg. 56,577 (Sept. 18, 2015) (announcing availability of draft control techniques guidelines for VOCs from the oil and gas sector).

- Remove the provision in Section 95669 that allows operators to reduce the inspection frequency from quarterly to annual based on the percent or number of leaking components detected.
  - Require the repair of 500 ppm leaks detected during inspections.
- Underground natural gas storage
  - Expand daily screening or continuous monitoring provisions to include all wells in the field including but not limited to observation, monitoring, disposal, production and other wells.
  - Clarify that the monitoring requirements apply not only to active wells but also to idle and plugged and abandoned wells.
  - Clarify that the inspection requirements in Section 95668 are intended to apply in lieu of the inspection requirements in Section 95669.
- Pneumatic controllers and pumps
  - Phase out existing low-bleed continuous devices, and require quarterly testing of bleed rate during phase out period.
  - Prohibit or phase out the venting of emissions from intermittent-bleed pneumatic controllers; or, at a minimum, limit emissions from such devices to low bleed levels, and require operators to verify that emissions are at low-bleed levels via direct measurement.
  - Clarify that the pneumatic pump provision apply to glycol assist pumps, and ensure that methane emissions from these pumps are indeed controlled.
- Compressors
  - Expand the requirement to perform LDAR inspections to rod packing and seals on non-production reciprocating compressors.
  - Reduce the flow rate threshold from that triggers a repair or replacement of the rod packing or seals.
- Separator and tank systems
  - Tighten deadlines related to both commencement of annual flash analysis testing and installation of vapor collection systems.
  - Require owners and operators of separator and tank systems that receive less than 50 barrels of crude oil per day and that receive less than 200 barrels of produced water per day to conduct periodic flash analysis testing.
- Liquids unloading
  - Revise definition of "liquids unloading" to remove "use of pressurized natural gas."
  - Require operators to keep personnel onsite when conducting manual liquids unloading activities.
  - Require reporting of an enhanced list of key parameters and conditions when emissions are vented during liquids unloading.

In addition, while we commend ARB for recognizing the importance of accounting for the near term impacts of methane, we urge ARB to revise its assumptions to use the most recent IPCC AR5 20-year GWP for methane from fossil sources of 87. In supporting technical documentation and analyses for the rule, ARB assessed impacts and benefits of methane and methane reductions using the IPCC AR4 20-year GWP of 72. Using the most updated information available will ensure that the results of analytics for the rule are as accurate and representative of methane impacts as possible.

II. Leak Detection and Repair

Frequent, comprehensive inspections of oil and gas facilities are a critical component of pollution prevention and mitigation. Direct measurement of emissions at a wide selection of oil and gas facilities across the country demonstrate that equipment malfunctions and poor maintenance can lead to significant pollution that is not represented in emission inventories. The direct measurement of scientific information demonstrates that oil and gas facilities are considerably leakier than industry reports, that operators do not and cannot predict when such failures will occur, and therefore, that frequent inspections with modern leak detection equipment are necessary to detect and promptly repair such leaks.

Fortunately, modern leak detection equipment exists to quickly and accurately find leaks. Moreover, frequent – namely, quarterly – inspections are highly cost-effective. Such inspections remove harmful pollution from the atmosphere, while also ensuring a safer and more efficient workplace.

1. *Field Studies Using Direct Measurement and Recent Incidents in California Demonstrate the Need for Frequent Instrument-Based Inspections: Significant Emissions May Emanate from Individual Components and Operations*

Up until recently, regulators have relied nearly exclusively on emission inventories in order to understand the magnitude of a particular pollution problem as well as the potential reductions associated with a proposed solution. Now, however, recent advances in science have added to our knowledge and understanding of emissions from oil and gas facilities. These studies demonstrate that emissions are systematically significant and, at a select number of facilities, actual emissions are magnitudes higher than emission inventories suggest. These studies strongly support at least quarterly inspections using modern leak detection technology to identify leaking equipment. In some instances, repairs can be made instantaneously with the turn of a wrench. A number of studies, as well as industry reports, note that the gas savings associated with fixing such leaks cover the costs associated with repairing them.

The first of these studies, conducted by an independent team of scientists at the University of Texas, found that emissions from equipment leaks, pneumatic controllers and chemical injection pumps were each 38 percent, 63 percent and 100 percent higher, respectively, than estimated in national inventories.[12] This study also found that 5 percent of the facilities were responsible for 27 percent of the emissions.[13]

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

[13] *See* Allen, D.T., et al, (2014), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environ. Sci. Technol*., 2015, 49 (1), pp. 633–640 (referencing 2013 Allen study), available at http://pubs.acs.org/doi/abs/10.1021/es5040156.

Two follow-up studies, focused specifically on emissions from pneumatic controllers and liquids unloading activities at wells, found similar results.[14] Specifically, the studies found that 19 percent of the pneumatic devices accounted for 95 percent of the emissions from the devices tested, and about 20 percent of the wells with unloading emissions accounted for 65 to 83 percent of those emissions. The average methane emissions per pneumatic controller were 17 percent higher than the average emissions per pneumatic controller in EPA's national greenhouse gas inventory.[15]

These findings were reiterated again in a series of direct measurement studies focusing on emissions from compressor stations in the gathering and processing segment and in the transmission and storage segment. The gathering and processing study found substantial venting from liquids storage tanks at approximately 20 percent of the sampled gathering facilities.[16] Emission rates at these facilities were on average four times higher than rates observed at other facilities and, at some of these sites with substantial emissions, the authors found that company representatives made adjustments resulting in immediate reductions in emissions.

In the study on transmission and storage emissions, the two sites with very significant emissions were both due to leaks or venting at isolation valves.[17] The study also found that leaks were a major source of emissions across sources, concluding that measured emissions are larger than would be estimated by the emission factors used in EPA's reporting program.

A recent helicopter study of 8,220 well pads in seven basins confirms that leaks occur randomly and are not well correlated with characteristics of well pads, such as age, production type or well count.[18] That study used statistical models to assess the relationship of detection to well pad parameters such as age, well count, gas and oil production. The study found a weak relationship between site characteristics and detected emissions. The study focused only on very high emitting sources, given the helicopter survey detection limit, which ranged from 35 to 105 metric tons per year of methane. The paper reports that emissions exceeding the high detection limits were found at 327 sites. 92 percent of the emission sources identified were associated with tanks, including some tanks with control devices that were not functioning properly and so could be expected to be addressed through a leak detection and repair program. While the study did not characterize the individually smaller but collectively significant leaks that fell below the

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[14] Allen, D.T. et al., "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings," *Environ. Sci. Technol*., 2015, 49 (1), pp 641–648, available at http://pubs.acs.org/doi/abs/10.1021/es504016r.

[15] Allen, D.T., et al, (2014), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environ. Sci. Technol*., 2015, 49 (1), pp 633–640, available at http://pubs.acs.org/doi/abs/10.1021/es5040156.

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

[17] R. Subramanian, et al, (2015) "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol*, available at http://pubs.acs.org/doi/abs/10.1021/es5060258.

[18] Lyon, et al., "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environ. Sci. Technol.*, 2016, *50* (9), pp 4877–4886, available at http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705.

detection limit, it nonetheless confirms that high-emitting leaks occur at a significant number of production sites and that total emissions from such leaks are very likely underestimated in official inventories.

These studies demonstrate the importance of frequent inspections as well as the importance of comprehensive inspection requirements that apply to the full suite of components and equipment that can lead to leaks and unintentional venting. Specifically, certain components such as valves and connectors, may leak over time due to normal wear and tear. Other types of equipment, such as controlled storage tanks and pneumatic devices, may vent excess emissions when operating improperly. We commend ARB on drafting an LDAR provision that applies to both types of equipment. Under the proposal, operators must inspect controlled storage tanks, separators, vapor collection systems, circulation tanks, pneumatic devices and components such as valves and flanges on a quarterly basis using leak detection technologies. This is a critical aspect of the proposal as a comprehensive program coupled with frequent inspections is necessary to ensure operators detect all sources of unintentional leaks and venting.

The heterogeneous, unpredictable and ever-shifting nature of equipment leaks suggest that frequent leak detection and repair is essential to help identify and remediate leaks. We therefore support the finalization of a quarterly, comprehensive inspection requirement in the rule.

2. Leading States and EPA Require Quarterly Inspections

Currently, five major oil and natural gas producing states require quarterly monitoring at oil and gas facilities. In addition, EPA recently finalized a quarterly inspection requirement for compressor stations. These existing requirements demonstrate that ARB's proposed quarterly inspection requirement is both reasonable and necessary in order for California to remain one of the leaders with respect to oil and gas emissions mitigation.

EPA has finalized a quarterly inspection requirement to detect methane and VOC leaks at compressor stations.[19] Per the NSPS, operators may conduct such inspections using either optical gas imaging equipment or Method 21. Components found to be leaking 500 ppm or greater with a Method 21 instrument must be repaired.[20]

Colorado was the first state to promulgate comprehensive LDAR requirements aimed at reducing methane, as well as other pollutant emissions from a diverse suite of oil and gas facilities. Colorado's rules require operators to inspect for and repair hydrocarbon leaks, consisting of methane as well as other organic compounds, at three types of facilities: compressor stations, well sites and storage tank batteries. The rules require quarterly inspections at mid-sized facilities.[21]

[19] 81 Fed. Reg. 35824, 35846 (June 3, 2016).
[20] *Id*.
[21] 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014). Quarterly inspections are required at gathering sector compressor facilities with uncontrolled emissions between 12 and 50 tons of VOCs from equipment

Colorado provides operators flexibility in determining what type of leak detection equipment to use and whether or not to quantify a leak. Operators may use either an IR camera, Method 21, or "other Division approved instrument based monitoring device or method."[22] To date, the Division has approved one additional device, the Rebellion photonics camera. If an operator chooses to quantify a leak, they must fix all leaks with a hydrocarbon concentration of 500 ppm from components located at new and existing well sites and new compressor stations.[23] At older, existing compressor stations, the leak threshold triggering repair is 2,000 ppm.[24]

Pennsylvania, the second largest shale gas producing state, requires quarterly inspections of all onshore gas processing plants and compressor stations in the gathering and boosting sector.[25] Like Colorado, Pennsylvania requires operators to inspect for and repair methane leaks as well as VOC leaks. Pennsylvania requires that operators utilize either a forward looking infrared camera ("FLIR") or "other leak detection monitoring devices approved by the Department".[26] Pennsylvania has also announced an intent to adopt a quarterly inspection requirement at new and existing well sites.[27]

Ohio also requires quarterly inspections for hydrocarbon, including methane, leaks at unconventional well sites.[28] Per the Ohio requirements, operators may use either a FLIR camera or a Method 21 compliant analyzer. When using a FLIR camera, a leak is defined as any visible emissions. When using an analyzer, a leak is defined using a 10,000 ppm threshold for all components except compressors and closed vent systems, which use a 500 ppm threshold. Ohio has also proposed to require quarterly inspections at other facilities, including compressor stations.[29]

Wyoming requires quarterly instrument-based inspections at all new and modified well sites in its Upper Green River Basin with the potential to emit 4 tons of volatile organic compounds from fugitive components,[30] and has proposed to require the same for existing well

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leaks and at well sites and tank batteries with uncontrolled emissions between 20 and 50 tons of VOCs from the largest condensate or oil storage tank onsite.

[22] *Id*. at § XVII.A.2.

[23] *Id*. at § XVII.F.6.a,b.

[24] *Id*. at § XVII.F.6.a.

[25] Pa. Dep't of Envtl. Prot., General Permit for Natural Gas Compression and/or Processing Facilities (GP-5), Section G, http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf

[26] PA GP-5, Section H.

[27] Pennsylvania DEQ, Oil and Gas Technical Advisory Board Meeting, Concepts for Proposed General Permit for Well Pads and Proposed GP-5 Modifications (Mar. 31, 2016), http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/TechnicalAdvisoryBoard/2016/March%2031/Oil%20and%20Gas%20Presentation%20-%20Methane%20Reduction%20Stds.pdf

[28] Ohio EPA, General Permit for High Volume Hydraulic Fracturing, Oil and Gas Well Site Production Operations, http://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf.

[29] Ohio EPA, Draft Permits Available for Comment, *see* proposal for 18.1 Equipment/Pipeline Leaks, available at: http://epa.ohio.gov/dapc/genpermit/permitsec.aspx

[30] Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Permitting Guidance (Sept. 2013), (WY Permitting Guidance) http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf

sites and compressor stations in the Basin.[31] Operators may use either Method 21 or an optical gas imaging instrument, or other approved instrument. Wyoming's rules and permit requirements are focused on reducing VOC and HAP emissions.

Utah requires quarterly instrument-based inspections at all new and modified well sites and tank batteries.[32] Utah allows operators flexibility in determining which type of leak detection to use to conduct the inspections. Operators may use an IR camera, Method 21 or a tunable diode laser absorption spectroscopy. Utah requires operators of facilities that produce at least 25,000 barrels of crude oil and/or condensate to inspect on a quarterly basis. Operators of facilities that produce less than 25,000 barrels of crude oil and/or condensate must inspect annually. Utah requires that operators inspect components in hydrocarbon service, thereby requiring operators to detect and fix methane as well as VOC leaks.

3. *Quarterly Inspections Are Highly Cost Effective*

Quarterly instrument-based inspections can remove significant methane, HAPs and VOCs from the atmosphere for very low costs. When considering the value of natural gas that can be sold to end users instead of being leaked into the air quarterly inspections simply make economic sense, and even more so when considering the co-benefits associated with reducing VOCs and HAPs. This is supported by ARB's analysis, which estimates that the LDAR provision can be achieved for a cost of $15 per ton of CO_2e reduced assuming savings and $17 per ton of CO_2e reduced not assuming savings.[33] Data from ICF, other states, LDAR service providers and companies similarly demonstrate that quarterly inspections are cost-effective:

- ICF. ICF developed a complex model to investigate the distribution of LDAR cost profiles at well sites. The results of the model indicate that the cost for LDAR using third-party OGI contractors ranges between $491–793 per facility, depending on facility size.[34] Further, the analysis found that quarterly LDAR is cost-effective at $258/metric ton of methane avoided for an average facility in the modeled distribution.[35]

- ICF is also in the process of compiling a model that assesses the costs and cost-effectiveness of inspections using Method 21. This model also investigates the distribution of LDAR costs at facilities of varying size and emissions profiles. In addition, the model estimates costs over a period of three years, rather than simply looking at inspection costs in year one of an inspection program. The preliminary results of this model indicate that the cost for using third-party Method 21 contractors to

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[31] Wyoming Department of Environmental Quality proposed changes to Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6, (UGRB proposal) available at http://soswy.state.wy.us/Rules/RULES/9868.pdf; WY Permitting Guidance, 22.
[32] GAO DAQE-AN149250001-14, II.B.
[33] ARB Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (May 31, 2016), http://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasisor.pdf
[34] ICF Leak Detection and Repair Cost-Effectiveness Analysis, December 4, 2015. Figures reflect survey and equipment costs per facility.
[35] *Id*. Cost is $10.32/MT CO_2e for an average facility in the distribution model, using a GWP of 25 and gas price of $3/Mcf.

perform quarterly inspections at production facilities is $8.58 per metric ton of CO_2e reduced.[36]

- Rebellion. In comments at an EPA public hearing on the proposed NSPS in Dallas, TX, Rebellion Photonics, the maker of a leak detection technology, noted that its services are available for $250 per site.[37] Rebellion noted that this cost is "turn-key," including data management services.

- Colorado. Colorado's economic analysis of its LDAR requirements assumed an hourly contractor rate of $134 (reflecting a 30 percent premium).[38] Assuming a per-site survey time of four hours, this hourly rate yields a total per-site survey cost of $536.[39]

- EPA. EPA determined compressor station quarterly inspections to be cost-effective, estimating that the agency's requirements would result in the reduction of 16,500 short tons of CH_4, 3,897 tons of VOCs, and 143 tons of HAPs at 525 compressor stations by 2020 at total annualized costs, including revenue from saved gas, of $9,780,000.[40] For gathering and boosting compressor stations, this equates to $685 per short ton of CH_4 reduced and $234 per short ton of VOC reduced. For compressor stations in the transmission and storage sectors, this equates to $251 per short ton of CH_4 reduced and $9,072 per short ton of VOC reduced.

- EDF also contacted a number of third-party service providers and equipment rental firms, which provided costs that support the reasonableness of EPA's determination. In particular, a FLIR presentation includes information from survey providers suggesting well-pad rates ranging from $300 - $800.[41]

- Noble and Anadarko submitted comments in response to the Colorado LDAR rule, stating that "the leak detection and repair requirements using instrument-based monitoring is [sic] a reasonable and cost effective way to reduce fugitive emissions at well production sites."[42] Additionally, the companies compiled a cost analysis for LDAR

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[36] Final results of the model and an accompanying report are forthcoming and will be submitted to ARB once final.
[37] Rebellion Photonics comments at the EPA hearing in Dallas, TX on September 23, 2015.
[38] Colorado Air Pollution Control Division, Final Economic Impact Analysis for Regulation Number 7, at 18. Colorado assumed slight longer surveys, approximately 6.1 hours, yielding third party survey costs of approximately $817.
[39] CDPHE Cost Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7.Table 14: Instrument Based Tank Inspections Based on Proposed Tiering.
[40] EPA Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Table 3-10, available at https://www3.epa.gov/airquality/oilandgas/may2016/nsps-ria.pdf.
[41] FLIR, OGI Service Provider Survey, March 2016, at 2-3 (Attachment 2). The presentation notes additional charges for travel but also notes potential discounts for multiple well surveys.
[42] Prehearing statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the matter of proposed revisions to Regulation Number 3, 6, and 7, available at

under the Colorado rule and found that, "Based on company-specific historic data and certain estimated values, Noble anticipates that LDAR monitoring at well production facilities would cost between approximately $260 and $430 per inspection…"[43]

- According to a presentation delivered by Jonah Energy at the WCCA 2015 Spring Meeting, total LDAR program costs were about $99 per inspection in the first year, decreasing to about $29 per inspection in the fifth year.[44]

4. Incentivizing Innovation and Continuous Improvement in LDAR Technologies and Approaches

Although frequent OGI and Method 21-based LDAR both offer feasible and highly cost-effective approaches to reducing leak emissions, advanced LDAR technologies – and protocols for using those technologies — are being swiftly developed and refined.

The methane leak detection technology landscape is highly dynamic, with innovation happening in real time, for example through ARPA-E's MONITOR project and EDF's Methane Detectors Challenge project in partnership with Shell, six other large producers and other stakeholders. It is crucial for new ARB rules to create space for innovative technologies, which may be able to deliver improved environmental performance at reduced cost. We strongly urge the agency to adopt a robust alternative compliance pathway that is minimally prescriptive and specifically creates an entry point for appropriately qualified/demonstrated methane selective and/or multiple hydrocarbon detecting approaches. Such an approach will help catalyze a race to the top in technology, reduce costs for the regulated community, and potentially boost environmental outcomes. We urge ARB to let operators choose from a list of approved devices, and to obtain approval from ARB for an equally effective device, rather than dictating technology in the rule. We note that ARB has proposed to allow operators of underground natural gas storage facilities to use screening instruments other than OGI or Method 21 to conduct inspections of wellheads and pipelines,[45] and that U.S. EPA included a pathway for operators to obtain approval to use innovative technologies to reduce fugitive emissions at well sites and compressor stations.[46]

Accordingly, we encourage ARB to provide operators with flexibility to seek approval for alternative methods of complying with LDAR requirements, provided that these alternative

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ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/PREHEARING%20STATEMENTS,%20EXHIBITS%20&%20ALTERNATIVE%20PROPOSALS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation%20(Noble%20&%20Anadarko)/Noble%20and%20Anadarko%20PHS.pdf.

[43] Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the matter of proposed revisions to Regulation Number 3, 6 and 7; Page 7, available at ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation/NOBLE_APC%20-%20REB.pdf

[44] WCCA Spring Meeting, Jonah Energy Presentation, May 8, 2015 delivered by Paul Ulrich.

[45] Proposed 17 C.C.R. Section 95668(i)(1)(B).

[46] 81 Fed. Reg. 35824, 35861 (June 3, 2016).

compliance options are at least as effective in reducing waste and emissions as OGI-based LDAR, and that the approval process is transparent and open to public participation.

5. *ARB Should Remove the Frequency Adjustment Based on Percent or Number of Leaking Components*

Given the geographic and temporal unpredictability of leaking equipment discussed above, one of the most important aspects of an LDAR program is the frequency with which operators inspect facilities. ARB has proposed quarterly leak inspection surveys, with provisions to allow operators to reduce the frequency to annual inspections based on the percentage or number of leaking components found onsite. These provisions fall far short of what is necessary to protect public health and the environment, and lag behind what EPA, leading states and companies have already demonstrated in practice. Accordingly, we urge ARB to finalize a quarterly inspection requirement and to remove the provisions that allow operators to reduce inspection frequency to annual.

The proposal creates perverse incentives by rewarding operators for failing to identify harmful leaks. EPA investigations at petroleum refineries and other types of facilities demonstrate this to be so. A 2007 report by EPA found "significant widespread non-compliance with [LDAR] regulations" at petroleum refineries and other facilities.[47] EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions."[48] The report recommends that "[t]o ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time," companies should monitor more frequently.[49]

Furthermore, neither the percent nor number of leaking components is an accurate predictor of a facility's emissions performance. At a conceptual level, if emissions from leaking components were homogenously distributed, the percentage of components leaking at a facility would be a good indicator of facility-level emissions. However, there is overwhelming evidence that leak emissions follow a skewed, highly-heterogeneous distribution, with a relatively few number of sources accounting for a large portion of emissions.

To estimate the extent to which the percent of leaking components correlates with a facility's emissions performance, we empirically examined the effects of EPA's proposed 1 and 3 percent thresholds using data from the City of Fort Worth Study Air Quality Study,[50] which includes both component level emissions information and site-level data. Figures 5 and 6 below show the results of this analysis. Figure 5 compares site-level emissions to the percentage of leaking components and demonstrates that the individual sites with the highest emissions fall below EPA's proposed 1 percent threshold. Figure 6 aggregates site-level emissions at each of these

[47] EPA, "Leak Detection and Repair: A Best Practice Guide," October 2007, at 1, *available at* http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf.
[48] *Id.* at 23.
[49] *Ibid.*
[50] Eastern Research Group, Inc. and Safe Environmental Consulting, LP, "City of Fort Worth Natural Gas Air Quality Study: Final Report," July 13, 2011, available at: http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf.

thresholds. Sites with less than 1 percent leaking components constituted over half of total emissions and over half of all sites. Conversely, there were no high-emitting sites with greater than 3 percent of their components leaking, and sites above a 3 percent threshold accounted for a small percentage of total emissions.

Figure 1: Site Methane Emissions (lb per year) Versus Percent Leaking Components

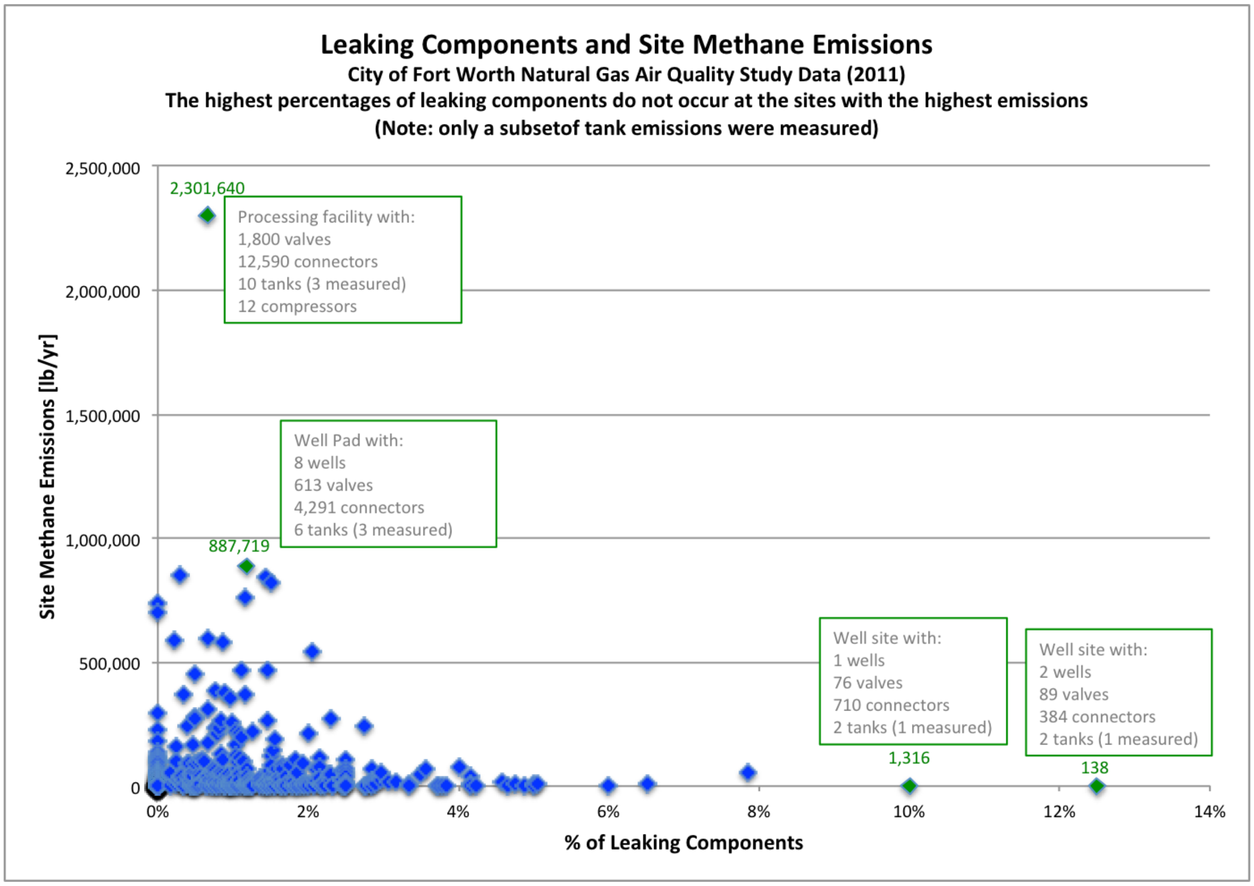
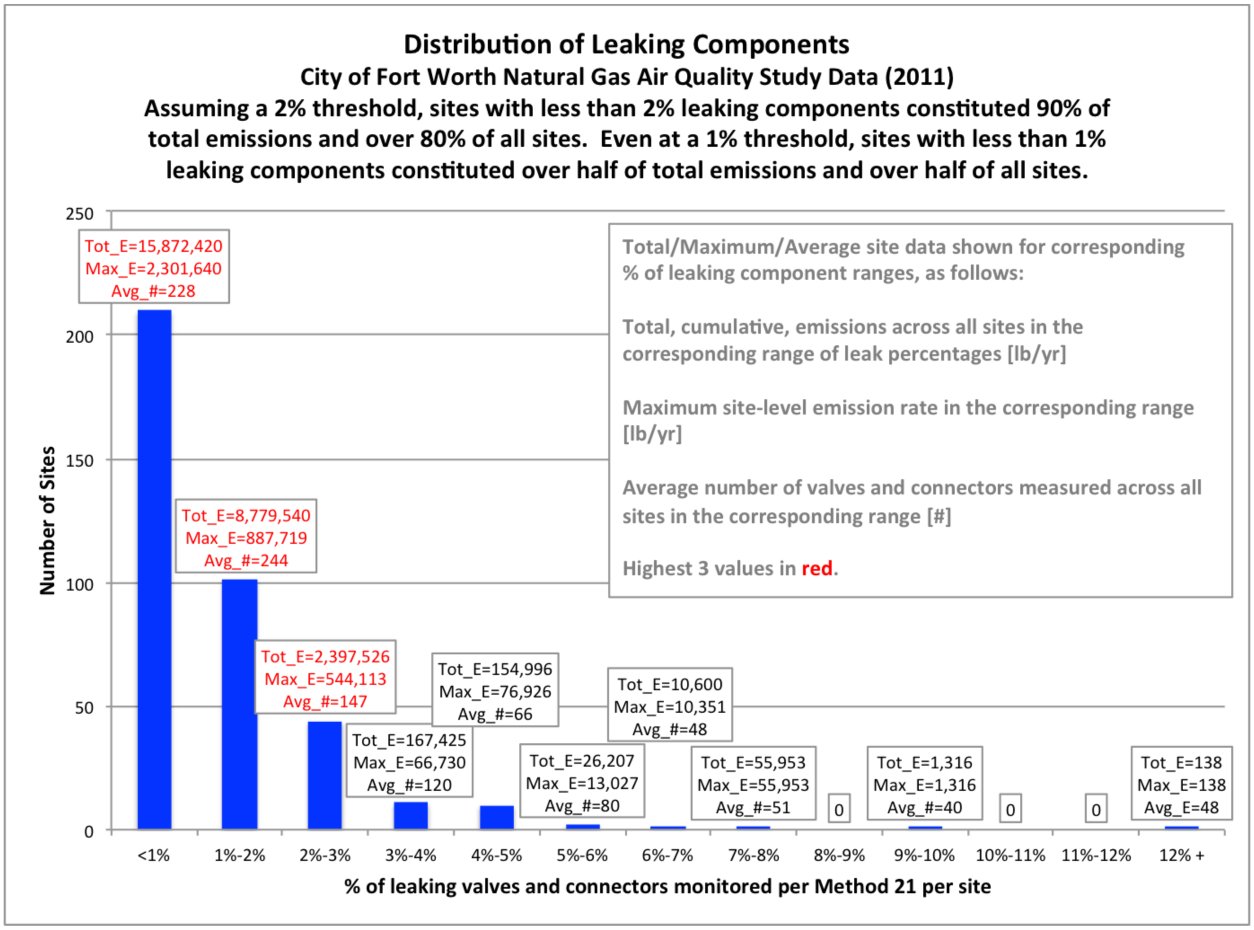


Figure 2: Number of Sites versus Percent of Leaking Valves and Connectors Monitored per Site (Method 21)



The number of leaking components is also a poor indicator of a facility's emission performance. To test this, we empirically examined the effects of BLM's proposed threshold using data from Allen, *et al.* (2013) and the Fort Worth Air Quality Study (2011),[51] which include both component level emissions information and site-level data. Figures 3 and 4 below show the results of this analysis. Figure 3 shows the distribution of equipment leaks across the 150 production sites measured in the Allen, *et al.* (2013) study; sites with two or fewer leaks represented 70 percent of sites and constituted half of total methane emissions from leaks. Conversely, only 30 percent of sites had more than two leaks, representing only half of all emissions. In the Allen, *et al.* (2013) dataset, the site with the highest measured methane emissions from leaks had only two leaks but represented 18 percent of all emissions measured across all sites.[52]

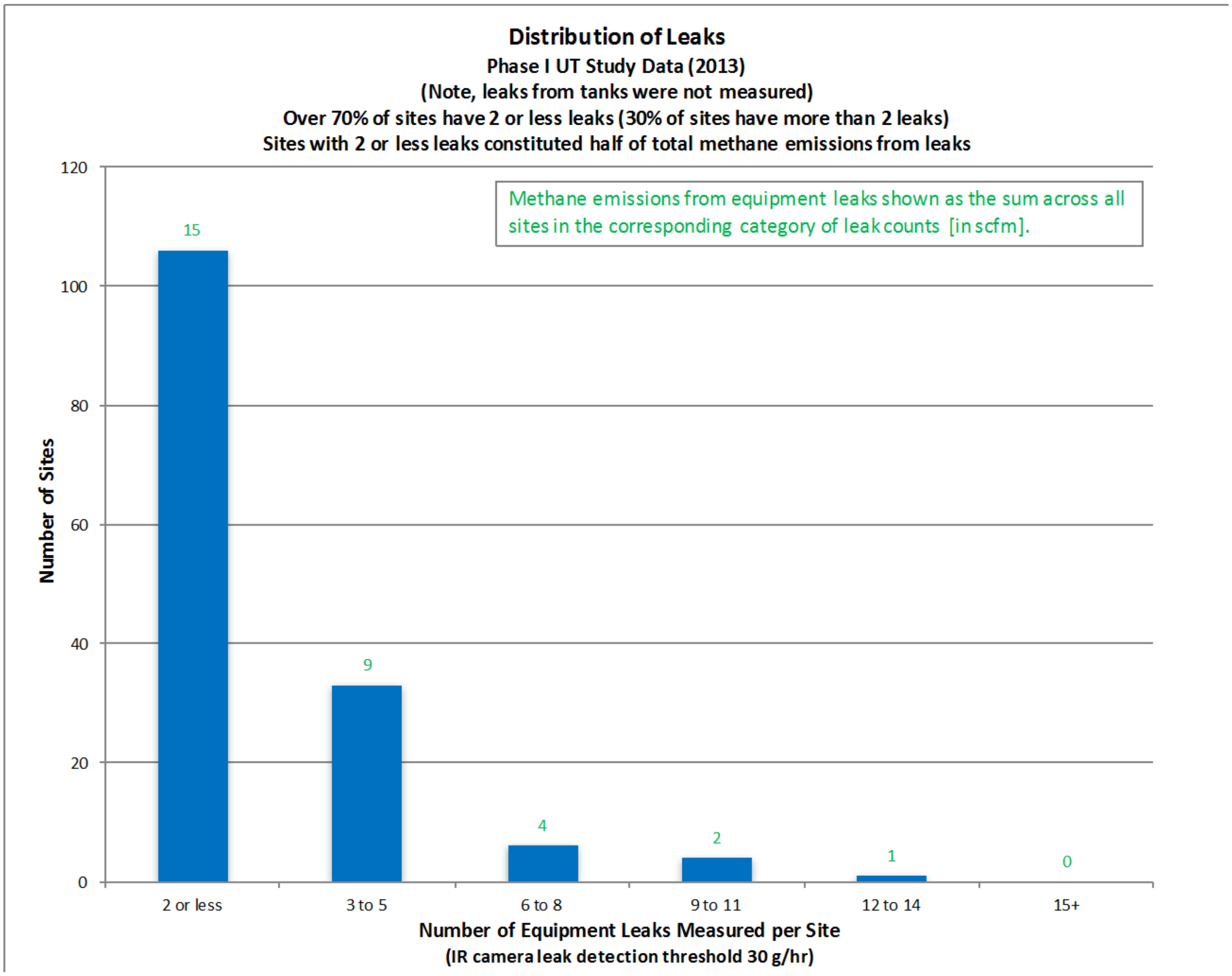
Figure 4 shows the distribution of leaks detected across the 388 sites measured in the Fort Worth Air Quality Study (2011); sites with two or fewer leaks represented 60 percent of sites and constituted 12 percent of total methane emissions from leaks. EPA reported in its Leaks White

[51] Fort Worth Study, Allen (2013)

[52] One leaking separator vent was responsible for 5 scfm methane at this site.

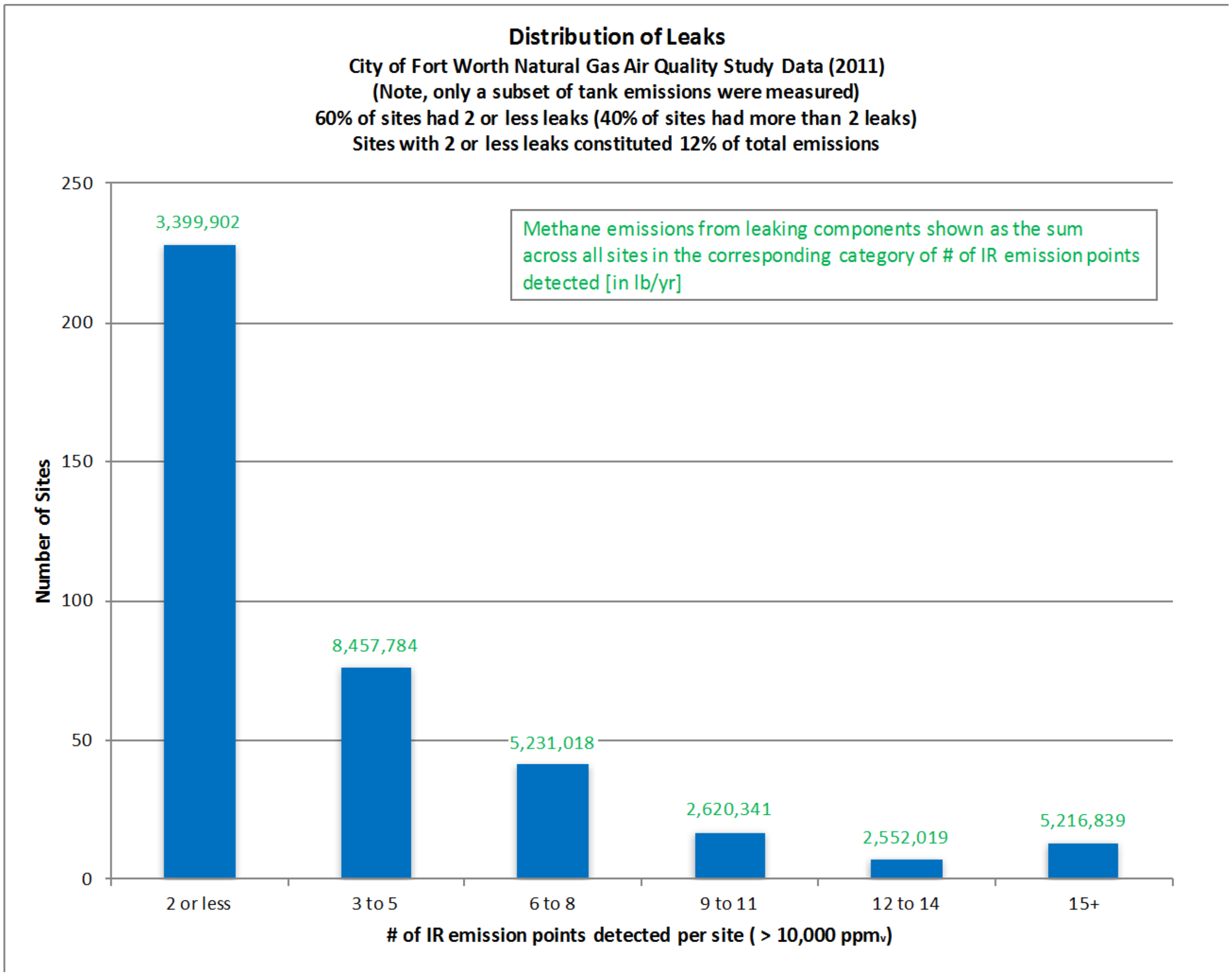
Paper that the well data provided in the Fort Worth report showed: “At least one leak was detected at 283 out of the 375 well pads monitored with an OGI technology with an average of 3.2 leaks detected per well pad; The TVA detected at least one leak greater than 500 ppm at 270 of 375 well pads that were monitored with an average of 2.0 leaks detected per well pad.”[53] These data indicate that significant emissions can occur at sites with few measured leaks.

Figure 3: Number of Sites versus Number of Equipment Leaks



[53] USEPA, “White Papers on Methane and VOC Emissions: Leaks,” *available at* https://www3.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf

Figure 4: Number of Sites versus Number of Large Leaks



Other LDAR rules, and information submitted by stakeholders during such rulemakings, further underscore the need for ARB to finalize a flat quarterly inspection requirement.

EPA recently finalized inspection requirements for well sites and compressor stations. EPA's final rules require operators to inspect compressor stations quarterly and well sites semi-annually. EPA removed a provision that appeared in the proposal that would have allowed operators to reduce the inspection frequency based on the percentage of leaking components identified during an inspection. As EPA noted, "most commenters opposed performance-based monitoring frequency" on the grounds that such an approach is "costly, time-consuming, and impose[s] a complex administrative burden for the industry and states."[54]

Colorado recently proposed, and ultimately adopted, a leak detection and repair requirement that requires operators inspect for leaks at all but the smallest sites on a continuous annual, quarterly, or monthly basis.[55] This proposal had the support of three large oil and gas

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[54] 81 Fed. Reg. at 35857.
[55] 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014).

producers, Noble Energy, Anadarko Petroleum Corporation, and Encana. Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to Encana, "Encana's experience shows leaks continued to be detected well into the established LDAR program."[56] Viewed somewhat differently, Encana's data suggests that while the largest reductions in VOC emissions occur in the first year of an LDAR program, significant emissions reductions are still being realized in subsequent years of the LDAR program."[57]

Other information presented during the Colorado rulemaking further supports the need for frequent inspections over time. During the rulemaking, industry opponents of the Division's proposal submitted data collected from their own LDAR monitoring experience. This data demonstrated an initial component leak rate frequency (before the first LDAR inspection) at new and modified gas processing plants of 1.7 percent.[58] The leak rate frequency falls to 0.4 percent after the first monitoring period and averages 0.3 percent over 12 consecutive calendar quarters. While it does support a decline after the first monitoring period, the data evidences a steady state of leak detection after that.

6. ARB Should Require All Leaks of 500 ppm be Repaired Upon Rule Implementation

The proposal sets the lowest leak threshold for the first year of the rule's implementation at 10,000 ppm, and then lowers this to 1,000 in year two. A 10,000 ppm leak is a large leak, and we are not aware of any technical or other justification for allowing smaller leaks that can be detected to go unmitigated. Method 21 and OGI are both capable of detecting leaks smaller than 10,000 ppm. Moreover, other leading states with LDAR programs that contain quantitative leak thresholds such as Colorado and Pennsylvania require operators repair much smaller leaks of 500 ppm.[59] US EPA uses a leak threshold of 500 ppm for a number of LDAR requirements for new facilities under NSPS Subpart OOOO.[60] We therefore urge ARB to lower the initial leak threshold to 500 ppm to be consistent with these other states and to reflect what is technically feasible.

III. Underground Natural Gas Storage Facility Monitoring.

We applaud ARB on proposing rigorous monitoring provisions at underground natural gas storage facilities. The recent leaks at Aliso Canyon and McDonald Island demonstrate the unpredictable nature of leaks and the potential for such leaks to cause very significant harm to

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[56] Rebuttal Statement of Encana Oil and Gas (USA) Inc., p. 10, Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3,7 and 9, on file with EDF.
[57] *Id*. at 10-11.
[58] Prehearing Statement of WPX Energy Rocky Mountain, LLC'S AND WPX Energy Production LLC, Ex. A, Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3,7 and 9, on file with EDF.
[59] 5 C.C.R. § 1001-9 XVII.F.6.b; Pa. Dep't of Envtl. Prot., Air Quality Permit Exemptions, No. 275-2101-003, http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.
[60] *See* 77 Fed. Reg. at 49490, 49498 (Aug. 16, 2016).

public health and the environment. The requirements that ARB has proposed will go a long way in ensuring that operators detect even small leaks immediately and repair them expeditiously.

To address leaks from underground storage facilities, ARB has proposed a combination of ambient air monitoring and equipment monitoring. Specifically, operators must install a system capable of continuously monitoring the ambient air at the facility that can be accessed by ARB or local agencies.[61] In addition, operators must perform either daily or continuous monitoring at wellheads, pipelines and the surrounding area within a 200 foot radius of the wellhead assembly.[62] Operators must measure all leaks identified by the daily inspections or the continuous monitoring system in accordance with Method 21 (excluding the use of PID instruments) within 24 hours of detecting a leak, and repair all leaks measured above the thresholds specified in Section 95669 (the general LDAR provision) according to the timeframes specified in Section 95669.[63] Operators must notify ARB within 24 hours any time a leak is measured above the maximum leak threshold specified in Section 95669 or any time an air monitoring system detects levels of natural gas that exceed more than 10 percent of baseline conditions.[64] These provisions could be read as giving operators 24 hours from detection to measure a leak, and a subsequent 24 hours to report that measurement to ARB – in other words, two full days between detection and reporting. We therefore request that ARB clarify that operators must both measure any leak and report that measurement to ARB within 24 hours of detection, as we believe that this time frame is sufficient to accomplish both. The rule also requires operators to maintain records of leak measurements and submit an annual report containing leak measurement data.[65]

The proposal contains a number of provisions that are critical to reducing the environmental, public health and safety threats of underground natural gas storage facilities. In particular, we strongly support the continuous ambient air monitoring combined with the daily or continuous equipment monitoring requirements. These provisions go beyond the requirements that currently apply to surface leak monitoring at natural gas storage facilities under emergency rules promulgated by the Division of Oil, Gas and Geothermal Resources (DOGGR) in response to the Aliso Canyon leak,[66] and also beyond new rules proposed by DOGGR. Indeed, per the DOGGR proposal, the ARB requirements will supersede the DOGGR surface leak monitoring requirements if ARB finalizes requirements that are at least as stringent, or more stringent, than DOGGR's rules.[67] The current draft meets this test.

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[61] 17 C.C.R. Section 95668(1)(i)(A).
[62] *Id*. at Section 95668(i)(1)(B),(C).
[63] *Id*. at Section 95668(i)(3),(4).
[64] *Id*. at Section 95668(i)(6).
[65] *Id*. at Section 95668(i)(7),(8).
[66] DOGGR, Emergency Regulations 14 C.C.R. Section 1726 et seq., available at http://www.conservation.ca.gov/index/Documents/DOC%202016-0126-03E%20Gas%20Storage%20Requirements%20-%20Final%20Text%20of%20Emergency%20Regulations.pdf
[67] DOGGR, Discussion Draft 14 C.C.R. Section 1726.7(e), available at http://www.conservation.ca.gov/dog/Documents/Public%20Discussion%20Draft%20-Requirements%20for%20Underground%20Gas%20Storage%20Proj.pdf

We also support ARB's proposal to provide flexibility to operators in choosing what type of leak detection technologies to use in performing the daily equipment inspections.[68] As we note in our comments on the general LDAR provision in Section 95669, we believe it is imperative that regulations incent or, at a minimum, allow for the use of emerging technologies, provided that there is a rigorous and transparent process whereby ARB can ensure that such technologies are at least as effective in detecting leaks as the methods explicitly allowed for in the rule. Along these lines, we urge ARB to issue clear guidelines that lay out the criteria for approval of "other screening instruments"[69] and provide an opportunity for public comment on any application to use an alternate screening instrument.

We support ARB's proposal to require either daily screening or continuous monitoring of each natural gas injection/withdrawal wellhead assembly, attached pipelines and the surrounding area within a 200 foot radius of the wellhead assembly for leaks of natural gas; however, we request that this be expanded to include not just injection/withdrawal wells, but all wells in the field including but not limited to observation, monitoring, disposal, production and other wells, as leaks can occur from any of these well types. We also request that ARB clarify that the monitoring requirements apply not only to active wells but also to idle and plugged and abandoned wells. Given the age and long operating histories of California's underground gas storage fields, monitoring all wells—not just active wells—is critical to detecting and stopping leaks. The Montebello and Playa Del Rey underground gas storage fields, for example, have long, documented histories of leakage from plugged and abandoned wells.[70]

Lastly, it appears from the proposal that the inspection requirements in Section 95668 are intended to apply in lieu of the inspection requirements in Section 95669. However, this is not explicitly stated in the proposal. We suggest ARB clarify this in the final rule.

IV. Pneumatic Controllers and Pumps

Pneumatic equipment – natural gas driven pneumatic controllers and pneumatic pumps – are the source of enormous amounts of methane pollution. US EPA estimates that, nationwide, pneumatic equipment emitted over 3,100,000 metric tons of methane in 2014 – or 32 percent of estimated methane emissions from all oil and natural gas sources. As we describe below, cost effective technologies can essentially eliminate these emissions. We commend ARB for proposing strong standards for pneumatic equipment, but as we describe below, the proposed standards would still allow significant emissions from these types of equipment, and as such, ARB must strengthen the proposal.

ARB's proposal:

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[68] See *Id*. at Section 95668(i)(1)(B)(providing that operators may use Method 21, OGI or "other screening instruments").
[69] *Id*.
[70] Chilingar, G. V., & Endres, B. (2005). Environmental hazards posed by the Los Angeles Basin urban oilfields: an historical perspective of lessons learned. Environmental Geology, 47(2), 302-317.

- Prohibits venting of natural gas from any newly installed[71] continuous-bleed pneumatic controller, regardless of the nominal bleed rate for the controller, and requires that all older continuous-bleed pneumatic controllers emit less than six standard cubic feet per hour (scfh), including provisions requiring operators to annually verify compliance with this limit with direct measurements of the rate of venting.

- Requires operators of intermittent-bleed pneumatic controllers to verify that these devices are not emitting natural gas between actuation as part of periodic leak-detection inspections.

- Prohibits venting of natural gas from pneumatic pumps.

No other state prohibits all venting from new continuous bleed devices or new and existing pumps located at the suite of facilities subject to this proposal, nor includes all pneumatic devices, including intermittent bleed devices, in leak detection and repair requirements. These provisions will go a long way towards reducing emissions from new continuous-bleed pneumatic devices and pumps, and improperly functioning intermittent and continuous-bleed devices and pumps. Joint commenters support these provisions.

Nevertheless, ARB's proposal will continue to allow significant pollution from pneumatic controllers. In particular, the proposal will allow "grandfathered" continuous-bleed controllers to operate indefinitely, provided that their emissions remain below six scfh. And, it will allow both new and existing intermittent-bleed controllers that vent to the atmosphere to continue operating - again, indefinitely. Allowing these polluting devices to remain in operation is not necessary because, as we detail below, cost effective technologies are available to eliminate, or at least greatly reduce, venting from pneumatic controllers. ARB must strengthen the proposal so that harmful methane emissions from pneumatic controllers do not continue unnecessarily.

1. *Zero-Emitting Alternatives to Natural Gas-Driven Pneumatic Controllers are Available*

A number of alternative technologies and approaches that can eliminate, or at least drastically reduce, venting of natural gas from pneumatic controllers are available and in-use today at oil and gas facilities in the United States and Canada. These technologies/approaches include:

- Using compressed "instrument air," instead of natural gas, to drive pneumatic controllers.
- Using electronic control systems and electric valve actuators, instead of pneumatic controller and valve actuators, for valve automation. As described below, this approach can be used both at sites where electricity is already available and at sites without power by installing solar powered systems.
- For some applications, pneumatic controllers are available that do not release gas to the atmosphere, but rather release gas to a pressurized gas line. These are typically referred to as "bleed-to-pressure" or "integral" controllers.

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[71] ARB's proposal would not allow venting from any continuous-bleed pneumatic controller installed after January 1, 2016.

- Gas released from pneumatic controllers can be routed to vapor collection systems (VCSs) or fuel lines.

Clean Air Task Force recently commissioned Carbon Limits to examine these and other alternatives to traditional, venting pneumatic controllers. Carbon Limits examined these technologies in detail, conducting numerous interviews with oil and gas producers who have utilized them and with suppliers of these systems. The first two technologies listed above, instrument air and electric systems, are inherently non-emitting technologies; Carbon Limits' research shows that these technologies are mature and proven, with successful installation at hundreds of sites in North America. Furthermore, Carbon Limits demonstrates that for almost any configuration of oil and gas facilities, at least one of these technologies is cost effective as a means of methane abatement as compared to unmitigated natural gas-drive pneumatic controllers.

Instrument Air. Compressed air can be used instead of natural gas to drive devices. EPA's 2012 OOOO NSPS standards require all pneumatic controllers at processing plants to be zero emitting,[72] and EPA presumes that most operators will use compressed "instrument air" systems to comply with this regulation.[73] Instrument air is a "well-established mature solution" to run pneumatic control systems and is in wide use globally. In fact, in some countries with significant oil production, instrument air systems are more common than natural gas-driven pneumatic controllers.[74]

Instrument air systems offer several advantages over natural-gas driven pneumatic controllers, in addition to reduced emissions of methane and other pollutants in natural gas:

- Increased revenue from sales of natural gas that would otherwise be vented by gas-driven controllers.
- For many sites, instrument air systems can be simpler and cheaper to maintain. For gas-driven controllers, maintenance costs are significant if the gas at the site is wet (condensation of heavier hydrocarbons interferes with pneumatic controller operations) or sour. These costs are avoided with instrument air. Instrument air is very reliable; in contrast some sites with low gas-to-oil ratios may need to purchase natural gas or propane from offsite in order to ensure that sufficient gas is always available to drive pneumatic systems. These costs are all avoided with instrument air systems.[75]

For sites with 20 or more pneumatic devices, instrument air is a cost effective and feasible approach to eliminate emissions from all types of pneumatic controllers and pneumatic chemical injection pumps or heat trace pumps when electric power is available from the grid or from on-site generators. Oil and gas production in California occurs largely in areas with access to electric power. Many centralized production sites and compressor stations have numerous

[72] 40 C.F.R. § 60.5390(b)(1).
[73] *See* EPA, TSD for the Proposed NSPS Subpart OOOO, 5-22 (July 2011).
[74] Carbon Limits, "Zero emission technologies for pneumatic controllers in the USA: Applicability and cost effectiveness" (2016) at 17.
[75] Carbon Limits at 18.

pneumatic devices. Retrofit of sites with instrument air is straightforward because operators can use existing pneumatic controllers and actuators with instrument air systems.

Electric Systems. Gas-driven pneumatic controllers can now readily be replaced with electric systems at sites with and without electricity already available. These systems include electric valve actuators, electronic controllers, control panels and wiring, and—for sites without power available from the grid or from pre-installed on-site generators—solar panels and batteries.

These systems have become more mature and robust in recent years and are in use at hundreds of oil and natural gas production sites in the United States and Canada.[76] Operators report that these systems are reliable.[77] Like instrument air, these systems offer several advantages over natural-gas driven pneumatic controllers, in addition to reduced emissions of methane and other pollutants in natural gas, including:

- Increased revenue from sales of natural gas that would otherwise be vented by gas-driven controllers.
- Like instrument air, greater reliability and lower maintenance for sites with wet or sour gas, which degrades performance of gas-driven pneumatic controllers, or for sites where sufficient and steady supply of natural gas is not available.[78]
- Easier and less expensive site level automation (for example, with Supervisory Control and Data Acquisition (SCADA) systems).[79] Installation of electric systems can greatly reduce costs for operators if they enable less frequent site visits. Furthermore, these systems can perform important functions such as shutting in wells in the event of large leaks, offering further environmental (and potentially health and safety) benefits. The value of these systems is recognized by ARB in the underground storage monitoring provisions of the proposed rules.

Cost Effectiveness of Instrument Air or Electric Systems as Alternatives to Gas-Driven Pneumatic Controllers. Instrument air and electric systems are mature, reliable technologies. When electric controllers are combined with solar power systems, these non-emitting technologies are widely applicable.[80] Indeed, these technologies are widely used in California. Data from the ARB Oil and Gas Industry Survey for 2007 shows that both of these approaches are very widely used in California. 37 percent of controllers in the state were electric, while 47 percent were instrument air driven (and a full 87 percent of valve actuators in the state were air driven).[81]

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[76] Carbon Limits at 12.
[77] Carbon Limits at 15.
[78] Carbon Limits at 15.
[79] Carbon Limits at 15.
[80] Carbon Limits reports that instrument air is applicable at larger sites (roughly 20 or more controllers on site) when power is available from the grid or from an on-site generator (*See* Carbon Limits at 18) and that electric controllers are applicable at sites of all sizes if power is available, and, in combination with solar power, applicable at smaller sites (20 or fewer controllers) when power is not otherwise available. *See* Carbon Limits at 15. However, Carbon Limits reports that there is no technical barrier to the use of electric controllers with solar panels at larger sites; there is simply little known precedent of this type of installation. *See* Carbon Limits at 16.
[81] ARB (2013), *2007 Oil and Gas Industry Survey Results - Final Report (Revised),* at Table 9-2.

Carbon Limits also found that these technologies are cost effective as alternatives to traditional gas-driven pneumatic controllers at a wide variety of oil and gas facilities. Carbon Limits used the capital and operating costs of these systems and traditional pneumatic controllers,[82] together with highly conservative estimates of emissions from gas-driven pneumatic controllers[83] and other parameters such as the value of conserved natural gas[84] to calculate the net cost of these systems per metric ton of avoided methane pollution, using a net present value formulation. Because there are a wide variety of site configurations for oil and gas sites, and because costs for these systems do not vary in a simple linear fashion with the number of controllers at the site and other parameters, Carbon Limits calculated the costs of both instrument air systems and electric systems for many permutations of a large number of site parameters, including:

- The number of pneumatic controllers at the site (1 – 40 controllers for electric systems, 21-40 controllers for instrument air systems).
- The number of pneumatic pumps at the site (0 – 1 pump).
- The type of pneumatic controllers at the site (from all continuous-bleed to all intermittent-bleed).
- The type of gas at the site (wet gas or dry gas).
- New site or retrofit site.
- Whether electricity is available at the site (for electric controllers at sites with 20 or fewer controllers).

Carbon Limits used US EPA's latest calculation of the social cost of methane (SC-CH_4) as the threshold for cost effectiveness. Specifically, they used the mean value of the SC-CH_4 calculated for a 3 percent discount rate for emissions in 2020, in 2016 dollars, or $1,354 per metric ton of methane, as the threshold.[85] Using the global warming potential for methane of 72, which ARB uses in this rulemaking, the abatement costs ARB calculates for the proposed standards translate to abatement costs within the range of the social cost of methane.[86] In fact, the total abatement costs for the rule are lower than the 2016-adjusted SC-CH_4 calculated by ARB.

[82] Costs were derived from interviews with oil and gas producers, system and component suppliers, and online quotes from component suppliers.
[83] Carbon Limits at 21-22.
[84] The report uses a very low price of natural gas, $2 per thousand cubic feet (mcf). *See* Carbon Limits at 21.
[85] EPA reports that the mean SC-CH_4 emitted in 2020, calculated with a 3% discount rate, will be $1,300 per metric ton CH_4 in 2012 dollars. *See* US EPA, "Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources" (May 2016) at 4-16. Available at: https://www3.epa.gov/airquality/oilandgas/may2016/nsps-ria.pdf. This is converted to $1,354 per metric ton in 2016 dollars using a cumulative rate of inflation of 4.2 percent.
[86] ARB Economic Analysis at Table B-2.

TABLE 1

ARB Rule Provision Methane Reduction Costs per Ton	VRU For Tanks	Reciprocating Compressors	LDAR	Pneumatic Devices	Well Simulations	Centrifugal Compressors	Total
Cost Per Ton ($/MTCH4 reduced)	$648	$288	$1,224	$288	$6,552	$144	$1,224
Cost Per Ton with savings ($/MTCH4 reduced)	$576	$72	$1,008	$72	$6,552	($72)	$1,080

Source: Table adapted from Table B-6 of Appendix B: Economic Analysis for the proposed rule. Costs in Table B-6 were converted to $/metric ton of methane using the IPCC AR4 20-year GWP of 72, per the ARB rulemaking analyses.

It should be noted that the SC-CH_4 costs are likely conservative. Experts widely acknowledge that social cost estimates are almost certainly underestimates of true global damages—perhaps severe underestimates. Using different discount rates; selecting different models; applying different treatments to uncertainty, climate sensitivity, and the potential for catastrophic damages; and making other reasonable assumptions could yield very different, and much larger, social cost estimates for carbon and methane.[87]

In general, replacing gas-driven pneumatic controllers with either instrument air or electric controllers (or both) is cost effective at the vast majority of site configuration, even with highly conservative assumptions about emissions factors for pneumatic controllers. This finding holds for both new installations and retrofit of existing sites with pneumatic controllers. In fact, Carbon Limits found that these technologies would *not* be cost effective for just a handful of site configurations. For example, at least one of the technologies is cost effective at:

- <u>All</u> sites with one (or more) pneumatic pumps.
- <u>Any</u> new wet gas site with more than two pneumatic controllers.

For large sites with electricity, instrument air is cost effective for:

- All retrofit sites.
- All wet gas sites.

As mentioned above, these results were calculated with very conservative (low) emissions factors for gas-powered pneumatic controllers. For example, at new sites, Carbon Limits assumes that each continuous-bleed pneumatic controller will have an emissions factor of 1.39 scfh.[88] This is EPA's emissions factor for low-bleed pneumatic controllers,[89] which operators are required to use for new continuous-bleed pneumatic controllers under NSPS Subpart

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[87] Richard L. Revesz, Peter H. Howard, Kenneth Arrow, Lawrence H. Goulder, Robert E. Kopp, Michael A. Livermore, Michael Oppenheimer & Thomas Sterner, *Global Warming: Improve Economic Models for Climate Change*, 508 NATURE 173 (2014). Available at:
http://www.nature.com/polopoly_fs/1.14991!/menu/main/topColumns/topLeftColumn/pdf/508173a.pdf
This study focuses on social cost of carbon, but the EPA NSPS RIA notes that "because the SC-CO2 and SC-CH4 methodologies are similar, the limitations also apply to the resulting SC-CH4 estimates." (RIA Section 4.3).
[88] Carbon Limits at 22.
[89] *See* for example, 40 CFR Part 98, Subpart W, Table W-1A.

OOOO.[90] However, both NSPS Subpart OOOO[91] and ARB's proposed standards for continuous-bleed pneumatic controllers (proposed § 95668(f)(2)(A)(1)) allow the use of devices that emit up to 6 scfh. Further, several recent studies based on measured emissions from pneumatic controllers have found higher average emissions from continuous-bleed pneumatic controllers classified as "low-bleed controllers."[92] If emissions factors consistent with these studies are used instead of the very conservative emissions factors used in the calculations described above, even more sites would have abatement costs below the SC-CH_4.[93]

In summary, Carbon Limits found that, even with very conservative assumptions, electric systems and instrument air systems are cost effective at a broad range of oil and gas facility site configurations.

Other Approaches to Eliminate Pneumatic Controller Emissions. It is important to note that other approaches can be used to eliminate emissions from pneumatic controllers, beyond instrument air and electric controllers. As listed above, two important approaches are use of "self-contained" or "integral" controllers which are designed to release the gas used in the controller into a gas pipeline, typically downstream of the controller and the valve it actuates, and routing emissions from pneumatic controllers to vapor collection systems. Data from the ARB Oil and Gas Industry Survey for 2007 shows that both of these approaches are in use in California. California operators captured gas from 6 percent of intermittent-bleed pneumatic controllers and 11 percent of piston valve actuators driven by natural gas, statewide; operators also reported 1,054 "no-bleed" controllers, which appear to self-contained/integral controllers (note that air-driven and electric controllers are separate categories in the survey).[94]

Carbon Limits notes that these technologies may be applicable and cost effective for oil and gas installations, and that they represent useful alternatives to instrument air and electric controllers.[95]

Summary. There are a number of non-emitting technologies and approaches that can be used in lieu of traditional gas-driven pneumatic controllers. All are in use in California. The most significant of these from both effectiveness and cost perspectives are instrument air and electric systems. Recent analysis by Carbon Limits shows that, even with very conservative assumptions, electric systems and instrument air systems are cost effective technologies to reduce methane emissions at a broad range of oil and gas facility site configurations.

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[90] 40 C.F.R. § 60.5390.
[91] 40 C.F.R. § 60.5390(c)(1).
[92] Allen, D.T., et al, "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," (2015) Environ. Sci. Technol., 49, at 633–640 ("Allen (2015)"), available at http://pubs.acs.org/doi/abs/10.1021/es5040156.
The Prasino Group, Determining bleed rates for pneumatic devices in British Columbia; Final Report, (Dec. 18, 2013), at 19, ("Prasino Study"), available at http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholdersupport/reporting-regulation/pneumatic-devices/prasino_pneumatic_ghg_ef_final_report.pdf.
[93] Carbon Limits at 27 – 28, 33.
[94] ARB, *2007 Oil and Gas Industry Survey Results - Final Report (Revised)*, (2013) at Table 9-2.
[95] Carbon Limits at 19-20.

2. ARB Should Phase Out Existing Low-Bleed Continuous Devices and Require Quarterly Testing of Bleed Rate

The proposed regulation is significantly weaker than the draft regulation that CARB posted on April 22, 2015. The proposal allows the use of continuous-bleed pneumatic devices installed before January 1, 2016, provided operators adhere to the provisions in proposed § 95668(f)(2)(A), which requires that these devices emit less than 6 scfh and that operators annually check that these devices are not emitting more than that amount and fix or replace them if they do emit over this threshold. This "grandfather" clause that allows for the *indefinite* use of continuous bleed devices is not warranted, in light of the fact that operators have a number of alternatives to continuous-bleed pneumatic controllers, and the finding that electric controllers and instrument air are proven, mature, widely applicable and cost effective technologies.

We thus recommend that ARB remove the provision allowing "low-bleed" continuous-bleed pneumatic devices that were in operation on January 1, 2016 to continue operating. If ARB concludes that such devices must be allowed to continue venting gas into the atmosphere, despite the numerous options operators have to eliminate these emissions, ARB must limit the period over which operators are allowed to continue these harmful emissions to at most a few years. Indefinite grandfathering is not warranted.

Further, the February 1, 2016 draft rule required operators to test existing devices "during each inspection period as specified in section 95669 by using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument)".[96] However, the current draft only requires annual testing.[97] As ARB provided no explanation for the change in testing requirements and testing devices during inspections is feasible and necessary to ensure bleed rate information is up to date, we recommend that ARB amend the current proposal to require testing during each quarterly LDAR inspection, as previously proposed.

3. Control Emissions from Intermittent-bleed Pneumatic Devices

ARB's proposal for intermittent-bleed pneumatic controllers will reduce emissions from these ubiquitous devices, due to the specific annual testing requirements to ensure that these devices do not leak gas into the air when not actuating.[98] However, we reiterate our concern that, beyond this provision, the proposed regulation, like previous drafts, does not limit emissions from these devices.

These devices are a very significant source of emissions. Oil and gas producers reported over 850,000 metric tons of methane emissions nationwide in 2014 from intermittent-bleed

[96] CARB Proposed Regulation Order, February 1, 2016 Draft, § 95668(f)(2)(C). Available at http://www.arb.ca.gov/cc/oil-gas/meetings/Draft%20ARB%20OG%20Regulation_Feb%201%202016%20Clean.pdf

[97] Appendix A: Proposed Regulation order § 95668(f)(2)(A)(3).

[98] Proposed § 95668(f)(3).

devices to US EPA's GHGRP, far higher than the 161,000 metric tons of methane they reported from continuous-bleed devices (both high-bleed and low-bleed).[99]

Intermittent-Bleed Controller Counts for California. There is very strong evidence that there are a significant number of intermittent-bleed pneumatic controllers in California. Operators in California oil and gas production basins reported over 4,100 tons of methane in 2014 from over 2,000 intermittent-bleed devices, while reporting no emissions at all from continuous-bleed devices (see Table 2).[100] Alarmingly, reported emissions from intermittent-bleed devices are increasing, both nationwide and in California (California counts leveled off between 2013 and 2014, see Table 3).[101]

Table 2. Device counts and methane emissions (in metric tons of methane) for high-bleed, intermittent-bleed, and low-bleed pneumatic controllers from oil and natural gas production basins in California as reported to US EPA's GHGRP for 2014. All listed AAPG oil and gas production basins are entirely within California. 730: Sacramento Basin; 745: San Joaquin Basin; 750: Santa Maria Basin; 760: Los Angeles Basin.

Pneumatic Device Counts, 2014

Device Type	CA Basins 730	745	750	760	Total (count)
High	0	0	0	0	0
Int	1,531	466	11	0	2,008
Low	0	0	0	0	0
				Total	**2,008**

Pneumatic Device Methane Emissions, 2014

Device Type	CA Basins 730	745	750	760	Total (MT CH4)
High	0	0	0	0	0
Int	3,289	817	21	0	4,127
Low	0	0	0	0	0
				Total	**4,127**

[99] US Environmental Protection Agency. Greenhouse Gas Reporting Program (GHGRP). Petroleum and Natural Gas Systems. W_PNEUMATIC_DEVICE_TYPE. Converted from metric tons carbon dioxide equivalent to metric tons of methane using a GWP of 25.
[100] *Id.*
[101] *Id.*

Table 3. EPA GHGRP Reported Onshore Production Pneumatic Device Counts by Type in California for 2011-2014. Counts are the sum of counts from the four basins shown in Table 2 above.

Pneumatic Device Type	2011	2012	2013	2014
High-Bleed Pneumatic Devices	23	-	-	-
Intermittent Bleed Pneumatic Devices	1,954	3,283	4,143	4,127
Low-Bleed Pneumatic Devices	16	-	-	-
Grand Total	**1,992**	**3,283**	**4,143**	**4,127**

Reporters to the GHGRP determine pneumatic device type "using engineering estimates based on best available information."[102] That is, operators make the determination as to pneumatic device type according to engineering assessments and available information regarding the device. Determining whether a pneumatic controller is designed to release gas intermittently or continuously is fairly straightforward. While emissions from these devices and the industry as a whole have received significant attention in recent years,[103] we are aware of no evidence or arguments that operators are over-reporting the number of intermittent-bleed controllers.

Further, according to the ARB Oil and Gas Industry Survey for 2007, there were at least 405 intermittent bleed pneumatic devices in California (accounting for about 25 percent of the total natural gas driven pneumatic controllers in the survey inventory). This information was reported a number of years ago, whereas the most recent GHGRP data is for 2014 and was reported in 2015. With the increased attention on emissions in recent years and the requirements of the GHGRP in place for several years, operators may now be more aware of the population of specific types of pneumatic controllers at their facilities than they were in 2007. In addition, operators may have installed more new intermittent-bleed controllers and/or replaced some of their continuous-bleed controllers with intermittent-bleed controllers in response to federal regulations that prohibit the installation of new high-bleed continuous controllers.[104]

Finally, we note that the ARB MRR data for various types of pneumatic controllers may be flawed. Unfortunately we have not been able to extract data for emissions specifically from intermittent-bleed controllers, or counts of intermittent-bleed controllers, from the publically available data from this program. However, the ARB MRR apparently requires operators to sort intermittent-bleed controllers into low-bleed and high-bleed categories (based on the 6 scfh threshold) for reporting controller *counts* in Cal e-GGRT, while *emissions* from all intermittent-bleed controllers are calculated using a single emissions factor (13.5 scfh), regardless of the bleed rate:

[102] 40 CFR § 98.233(a)(3).
[103] For example, *see* Allen, D.T., *et al.* (2015); also US EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2014: Revisions to Natural Gas and Petroleum Production Emissions*, (2016). Available at: https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2016-Main-Text.pdf
[104] 40 C.F.R. OOOO (2012).

> 3.14 How should emissions from unmetered, natural gas-powered intermittent-bleed pneumatic devices be quantified and reported, if the operator has documentation demonstrating that the actual bleed rate for the devices is less than six scf per hour?
>
> Pursuant to MRR, "intermittent bleed devices which bleed at a cumulative rate of six standard cubic feet per hour or greater are considered high bleed devices" (section 95102(a)(252)), therefore, *emissions from devices that exceed this limit must be reported as high-bleed* in Cal e-GGRT and are subject to a compliance obligation under the Cap-and-Trade Program. A low-bleed pneumatic device is defined in MRR as a device that "vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour" (section 95102(a)). *Low-bleed pneumatic devices must be reported as low-bleed* in Cal e-GGRT and emissions from such devices are not subject to a compliance obligation under the Cap-and-Trade Program.
>
> *Emissions from all unmetered, natural gas-powered intermittent-bleed pneumatic devices must be quantified using the "intermittent bleed" emission factor of 13.5 scf/hour/component* listed in Table 1A of Appendix A of MRR, using Equation 2 (section 95153(b)), *regardless of bleed rate.* If the operator has documentation that demonstrates that the devices bleed at an actual rate of less than six scf/hour/component, such as original equipment manufacturer's specifications, or measurement data, the operator must still quantify the emissions using the 13.5 scf/hour/component emission factor; however, the emissions may be reported as "low bleed" pneumatic emissions in Cal e-GGRT. If the device bleeds at a rate of six scf/hour/component or greater, or there is no documentation available that demonstrates that the actual bleed rate of a device is less than or equal to six scf/hour/component, the emissions for such devices must be reported as "high bleed" pneumatic device emissions in Cal e-GGRT.[105]

This treatment of intermittent-bleed pneumatic controllers is confusing at best and suggests that ARB MRR data may not be usable to differentiate intermittent-bleed and continuous-bleed controller counts and emissions.

In summary, the available evidence shows that there are thousands of intermittent-bleed pneumatic controllers in California, with thousands of metrics tons of methane emissions. Since the proposed regulation does not allow new installation of continuous-bleed pneumatic controllers that vent to the atmosphere, but allows continued installation of intermittent-bleed pneumatic controllers, we can expect more intermittent controllers to be installed in the future, making this source of methane pollution grow.

Emissions from Properly-Operating Intermittent-Bleed Pneumatic Controllers can be Substantial. While ARB's proposal addresses one important source of emissions from intermittent-bleed pneumatic controllers – the fact that they frequently operator improperly and emit continuously – the emissions from properly operating devices will remain high without additional standards.

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[105] ARB (2016), *Petroleum and Natural Gas Systems Emissions Reporting Guidance for California's Mandatory Greenhouse Gas Reporting Regulation,* at Section 3.14 (emphasis added). Available at: http://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/oil-gas.pdf

Not all intermittent-bleed devices actuate frequently under normal and expected operating conditions – but some actuate very frequently, and therefore emit large amounts of natural gas. For example, Allen *et al*. (2015) observed that controllers for emergency shut-off devices (ESDs) made up 12 percent of the population of controllers that they studied.[106] These devices will actuate very rarely, if at all. In contrast, some intermittent-bleed devices actuate very frequently. Of the 377 devices studied by Allen *et al*. (2015), 24 were intermittent-bleed devices that actuated at least 10 times during the sampling period, which was typically 15 minutes. Four actuated over 50 times while sampled.[107] These devices can emit at high levels – five of the 40 highest emitting devices studied by Allen *et al*. (2015) are intermittent-bleed devices that the researchers assessed to be operating properly.[108] These controllers emitted up to 40 scfh of whole gas.[109] Devices with certain specific functions, such as level controllers on separators, are likely to actuate frequently.

Since the proposed standard for intermittent-bleed pneumatic controllers does not limit emissions during actuation in any way, operators would not be required to reduce these high emissions in any way.

Suggested Approach. As noted above in Section X.1, reliable non-emitting alternatives to intermittent-bleed pneumatic controllers are available today. These technologies are mature and generally applicable and have been deployed at hundreds of sites, including in California. Critically, using these technologies as alternatives to intermittent-bleed pneumatic controllers is cost effective as a means of reducing methane emissions.

As such, ARB's standards should prohibit or phase out venting emissions from intermittent-bleed pneumatic controllers to the atmosphere. If ARB concludes that it is warranted, specific treatment of certain intermittent-bleed devices that very rarely actuate, such as ESDs could be appropriate. However, the fact that some controllers very rarely actuate cannot be used to justify inaction for the entire class of intermittent-bleed controllers.[110]

If ARB concludes that a simple standard prohibiting venting from intermittent-bleed pneumatic controllers is not warranted, despite the numerous alternative approaches and technologies that can be used to entirely avoid these emissions, then a standard that limits emissions from these devices is needed. Even where venting natural gas-driven pneumatic devices are used, lower-bleed intermittent pneumatic devices are available. Properly designed intermittent bleed devices can emit below 6 scfh in many applications.[111] The US EPA

[106] Allen D.T. *et al.*, (2015)
[107] Derived from analysis of table S4-1 in Allen *et al.* (2015) supplemental information.
[108] *See* Allen *et al*., Supporting Information, section S-8 (2015). Temporal profiles of emissions from the 40 highest-emitting controllers sampled in the study are shown. Controllers LB01-PC01, LB07-PC01, LB04-PC01, LB06-PC05, and LB04-PC03 – five of the 40 highest emitting controllers – are clearly intermittent devices which were assessed to be "operating as expected."
[109] *Id.* Controller LB01-PC01 emitted 40.2 scfh whole gas; the range for the controllers listed in the previous footnote was 19.1 – 40.2 scfh.
[110] Since some intermittent-bleed devices actuate very rarely, their emissions are low. These devices bring the average emissions factor for intermittent-bleed devices down.
[111] In their comments on EPA's 2012 oil and gas rules, the American Petroleum Institute stated, "Achieving a bleed rate of < 6 SCF/hr with an intermittent vent pneumatic controller is quite reasonable since you eliminate the

emissions factor for intermittent bleed pneumatics in natural gas transmission is 2.35 scfh,[112] well below 6 scfh. Wyoming requires *all* pneumatic controllers to be low emitting, regardless of whether they are continuous-bleed or intermittent-bleed, at new and modified facilities.[113] ARB could require operators to measure emissions from intermittent-bleed devices just as operators of continuous-bleed devices would be required to measure emissions. To verify that emissions were not above the threshold in the standard, a simple sampling protocol could be written, requiring measurement over a certain period of time, capturing emissions from any actuations that occurred during that time. Straightforward specifications for the time response and dynamic range of instrumentation could ensure that the devices used for these measurements accurately quantify the high flow rate from the controller occurring during actuation. This measurement approach would be similar to that used during a number of recent measurement studies of pneumatic controllers and other equipment, which included measurements from pneumatic controllers.[114]

Standards as described above would substantially reduce methane emissions at a reasonable cost, and serve as an important model for reducing emissions from pneumatic controllers in other jurisdictions.

4. *Pneumatic Pumps*

We commend ARB's proposal to require capture of all emissions from natural gas-driven pneumatic pumps. Pneumatic pump emissions can readily be routed to vapor collection systems; US EPA now requires emissions from new pneumatic pumps to be routed to a control device if such a device is on the site where the pneumatic pump is installed.[115] Electric pumps are also available to perform the duties of pneumatic pumps. For example, solar-powered chemical injection pumps are quite common,[116] and in general pumps can be electrified when electric controllers are adopted at a site, including when solar panels are used to power the systems. In fact, these systems become significantly more cost effective when they include electrification of a pneumatic pump.[117]

We believe that ARB intends the standards to apply to glycol assist pneumatic pumps, referred to as "Kimray Pumps" in EPA's GHG Inventory. These pumps are estimated to emit 76,418 metric tons of natural gas per year (nationwide), while chemical injection pumps are

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continuous bleeding of a controller." In fact, API advocated intermittent-bleed devices to achieve the 6 scfh bleed rate, rather than continuous low-bleed devices. American Petroleum Institute, "Technical Review of Pneumatic Controllers," at 7 (Oct. 14, 2011), available as Attachment K to American Petroleum Institute, Comment on OOOO New Source Performance Standards (Nov. 30, 2011), http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4266

[112] 40 C.F.R. Pt. 98, subpart W, Table W-3.

[113] This requirement is applied to intermittent-bleed controllers in addition to continuous-bleed controllers (email from Mark Smith, WDEQ, to David McCabe, September 22, 2014. Available at: http://www.arb.ca.gov/cc/oil-gas/meetings/CATF_et_al_attachment2_02192016.pdf)

[114] Allen, D.T., et al., "Measurements of methane emissions at natural gas production sites in the United States," (2013), Proc. Natl. Acad., 110, ("Allen (2013)"), available at http://www.pnas.org/content/110/44/17768.full Allen *et al*. (2015), Prasino Study.

[115] 40 C.F.R. § 60.5365a(h) and § 60.5393a.

[116] Carbon Limits at 13.

[117] Carbon Limits at 26.

estimated to emit 321,777 tons.[118] Control of emissions from glycol assist pumps is somewhat less straightforward than control of emissions from chemical injection pumps, because the natural gas used to drive the pump is typically emitted via the dehydrator vent stack. However, there are a number of options to eliminate emissions from these pumps. Electrification is an option for these pumps, just as it is for chemical injection pumps.[119] A secondary option is the use of a low-pressure glycol separator, which can separate methane-rich gas from the glycol before it enters the regenerator.[120] If this is done, the gas can be used to fuel the boiler on the regenerator or otherwise consumed for fuel on-site.[121] Finally, controls are often used to reduce emissions from dehydrator vent stacks. However, some of these controls, which are typically designed to reduce emissions of volatile organic compounds and hazardous air pollutants, will not reduce methane emissions from the dehydrator vent stack even when operating correctly.[122] Methane from a glycol assist pump will not be abated by these types of dehydrator controls.

ARB must ensure that all methane emissions from glycol assist pumps are properly controlled and that operators are not relying on dehydrator vent stack controls that will not properly control methane, such as condensers or carbon absorption systems, to control methane emissions from these pumps. As described above, there are a number of means to eliminate methane emissions from these pumps. Of course, in the case of dehydrators with controls that do not reduce methane emissions, the most appropriate approach would be to improve the emissions control on the dehydrator to reduce methane emissions from the glycol assist pump and from the dehydrator itself.

V. Reciprocating Compressors

We support ARB's approach to control emissions from all compressors, both in the production and non-production segments, through either vapor collection systems or through requirements to measure emissions at the vent point and to repair when those emissions exceed thresholds. The scope of ARB's proposed requirements on compressors is commendable as it addresses the emissions of compressors on well pads – something that EPA's recently finalized subpart OOOOa regulations fail to do. Moreover, measurement from compressors located in the midstream segments – those at natural gas gathering and boosting stations, processing plants, transmission compressor stations and underground storage facilities – will provide more useful data on the emissions of those compressors.

Furthermore, it is encouraging that pursuant to section 95668(d)(3)(A) and 95668(d)(3)(B), CARB's proposal would require inspections for leaks originating from compressor components and rod packing seals from production compressors at the same

[118] GHG Inventory, 2016. Annex 3. Tables A-127, A-134, A-136.
[119] 80 Fed. Reg. at 56,627.
[120] Kimray, Inc., "Glycol Pumps Product Bulletin," (July 2011), at 3.
[121] *Id*.
[122] For example, the National Emissions Standards for Hazardous Air Pollutants applicable to glycol dehydrators at certain facilities (NESHAP Subpart HH) allows the use of condensers or carbon absorption systems to control emissions. *See* 40 C.F.R. § 63.771(d)(1)(ii) and § 63.771(f)(1)(ii). These systems will not control methane emissions (the boiling point of methane is far too low for it to be captured by a condenser, and methane is not absorbed by activated charcoal to any significant degree).

frequency as that required by the LDAR provisions in section 96669(g).[123] Likewise, ARB's proposal requires frequent inspection of non-production compressor *components.*[124] However, CARB should extend that same requirement for frequent checks to emissions from rod packing seals to non-production compressors.

While ARB's proposed rule has many helpful and protective requirements, it should be strengthened. Since even the best new, properly installed rod packing seals allow some escape of natural gas,[125] vapor collection systems should be required whenever possible. We agree that there should be an alternative option to monitor emissions by measuring and repairing rod packing when the measured flow rate exceeds an established threshold, but that alternative should be applicable only when utilization of vapor collection system is not feasible. We note that the Ohio EPA has released a draft general permit that requires operators to capture all emissions from reciprocating compressor rod packing and direct those emissions to sales, fuel lines, or 98 percent control.[126] Even if directing collected vapors to one of the uses described under proposed section 95668(c)(2) is not possible, ARB should require operators to capture and control emissions with a vapor control device as described in proposed section 95668(c)(3)-(4).

We commend ARB for requiring flow rate measurements at the rod packing or seal vent stack, as opposed to measuring hydrocarbon concentration, for compressors at gathering and boosting stations, processing plants, transmission compressor stations and underground natural gas storage facilities. This method of direct flow rate measurement (*i.e.*, high volume sampling, bagging or calibrated flow measuring instrument) provides a much more accurate representation of the actual emissions, whereas hydrocarbon concentration is more weakly correlated with emissions.[127] Routing emissions through a vent stack makes measurements more accurate and more feasible for operators. However, as was the case with the draft standards, ARB's proposed regulations still only require annual measurements for non-production compressors when a vapor collection system is not installed. ARB should finalize a quarterly measurement frequency under proposed section 95668(d)(4)(B). Infrequent annual measurements can lead to two problems. First, annual measurements would allow potentially elevated emissions to continue over a longer period than quarterly measurements would allow. Second, the lax annual frequency could encourage operators of non-production compressors without vapor collection systems to continue operating without such systems. Therefore, ARB should require quarterly measurements for non-production compressors. As we have argued previously, direct measurement of emissions rates with instruments such as flow meters and high-flow samplers is inexpensive and some vendors providing LDAR service routinely measure emissions rates in this manner; requiring measurement of the emission rate at every regular LDAR inspection would only entail very minimal additional cost.

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[123] As discussed in more detail above, improvements to the section 95669 are needed.
[124] Proposed section 95668(d)(4)(A).
[125] *See* CARB Staff Report at 97, Table 9 (citation omitted).
[126] Ohio EPA, General Permit 17.1 Template, C(1)(b)(1)(d), available at http://epa.ohio.gov/dapc/genpermit/permitsec.aspx.
[127] Clearstone Engineering et al. (2006), *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*, 3 (available at http://www.epa.gov/gasstar/documents/clearstone_II_03_2006.pdf).

Additionally, the flow rate threshold at which ARB would require repair or replacement of rod packing or seals is far too high. As proposed, section 95668(d)(4)(D) requires repair of rod packing or seals when the measured flow rate is greater than 2 scfm per cylinder. ARB's analysis shows that using this threshold will result in costs of \$1.17/MT CO2e, or \$84/MT methane.[128] Based on the Oil and Gas Industry Survey, ARB's analysis assumes that a compressor over 250 HP has on average 3.45 cylinders, and that the average leak rate for a cylinder during pressurized operation is 0.9 scfm.[129] Data from the survey shows that the average compressor cylinder that is emitting over the threshold of 2 scfm is emitting 3 scfm.[130] In calculating the reductions, ARB simply estimated a reduction of 1 scfm per cylinder in order to comply with the proposed standard.[131] This vastly underestimates the emissions reductions that would be achieved under the proposed requirement to repair rod packing or seals if the flow rate exceeds 2 scfm.

As shown in ARB's Staff Analysis, a rod packing flow rate of 2 scfm is labeled as "poor" condition.[132] Presumably, ARB's proposed regulation would require an operator to repair the rod packing to better than poor condition. Indeed, EPA estimates that new rod packing should emit 11-12 scfh, or roughly equivalent to 0.19 scfm. We recalculated abatement costs using the same methodology and cost inputs as ARB used in the Economic Analysis. However, for the emissions reduction achieved by the rule, we used 2.81 scfm (3 scfm to 0.19 scfm) instead of 1 scfm (3 scfm to 2 scfm) as ARB used. The resulting costs were -\$1.27 per ton CO2e, *i.e.* the policy has net savings for operators.

Using a slightly different approach to calculating abatement cost from EPA's Natural Gas Star, but with ARB's cost assumptions[133] we calculated a number of different net abatement costs using the reductions that would be achieved using EPA's 0.19 scfm emission rate for a new rod packing.[134] The abatement costs calculated this way are somewhat different, but they appear to be more conservative than ARB's calculations and they show net savings at ARB's current repair threshold of 2 scfm, consistent with the calculation shown above. As Table 4 shows, ARB's cost analysis substantially overestimates the actual cost to operators and the costs of significantly tighter standards than ARB's proposed standard would be reasonable. At a flow rate threshold of 2 scfm the net cost per ton of methane removed is actually negative, meaning operators would make more money from the sale of the conserved gas than they incurred in costs. The total cost would be zero if ARB lowered the flow rate threshold to 1.82 scfm, and the net abatement cost approaches ARB's estimated average cost for the entire regulation at 0.48 scfm.

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[128] ARB, *Appendix B: Economic Analysis*, at B-34.
[129] Appendix B at B-29.
[130] Appendix B at B-29.
[131] Appendix B at B-29.
[132] ARB, *Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, Staff Report: Initial Statement of Reasons*, at 97, table 9.
[133] A cost of \$6,000 per rod packing, a 5 percent interest rate, an average of 6,546 pressurized operating hours and a price of \$3.44/mcf for gas.
[134] US EPA "Reducing Methane Emissions from Compressor Rod Packing Systems" (2006), available at: https://www3.epa.gov/gasstar/documents/ll_rodpack.pdf

Table 4

Replacement Threshold		Net Abatement Cost		
scfm	scfh	$/metric ton methane	$/metric ton CO2e (72)	$/mcf
2	120	-$22	-$0.31	-$0.3
1.82	109	$0	$0.00	$0
0.86	51	$331	$4.59	$5
0.61	37	$662	$9.19	$10
0.50	30	$992	$13.78	$15
0.48	29	$1,059	$14.70	$16
0.47	28	$1,125	$15.62	$17
0.43	26	$1,323	$18.38	$20
0.42	25	$1,389	$19.30	$21

Accordingly, CARB must reduce the threshold at which replacement or repair of rod packing is required. A standard set in the 0.4 – 0.5 scfm range would be cost-effective and more appropriately balance the need to reduce methane emissions, and the social costs of those emissions, while keeping costs for industry reasonable.

Finally, ARB should consider finalizing a requirement for operators of production compressors to perform direct measurement of the flow rate in a manner consistent with non-production compressors, as opposed to requiring repair based on concentration thresholds. As described above, the additional cost of direct emissions measurement during regular LDAR inspections would be quite small.

VI. Separator and Tank Systems

1. ARB Should Remove the "Low Production" Exemption

We urge ARB to remove the exemption for separator and tank systems that receive less than 50 barrels of crude oil per day and that receive less than 200 barrels of produced water per day. ARB added this exemption based on its own analysis of flash test data that indicated that emissions from such separation and tank systems will not reach the control threshold of 10 metric tons of methane per year.[135] This exemption is overly broad and may result in tanks that in fact exceed the control threshold going uncontrolled. ARB already proposes to require owners and operators of separator and tank systems covered by Section 95668(a) to either control emissions or conduct periodic flash analysis testing to determine whether or not controls are warranted. Owners and operators of separator and tank systems that receive less than 50 barrels of crude oil per day and that receive less than 200 barrels of produced water per day should still be required to conduct periodic flash analysis to ensure that any increase in production does not

[135] Statement of Reasons, 90.

result in methane emissions that trigger the control requirements. If ARB's analysis is correct, and emissions from such systems remain under 10 metric tons of methane annually, owners and operators will only be subject to the periodic modest flash analysis testing requirements which should not impose a significant burden on operators. For these reasons, we urge ARB to remove this exemption.

2. *Testing Should Occur Earlier and Controls Should be Installed Sooner*

ARB should tighten deadlines related to both commencement of annual flash analysis testing and installation of vapor collection systems. In previously submitted comments, we expressed concern that the prior version of the draft regulation allowed vessels to operate without any emission controls for an unjustifiably long period of time. Section 95668(a)(3) of the current draft provides that "[b]y 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" (with no requirement to actually control emissions unless this analysis demonstrates emissions in excess of ten metric tons of methane per year). While the prior draft of the rule required that annual flash analysis testing be conducted beginning January 1, 2017 and by no later than September 1, 2017, the latest draft clarifies the deadline for existing systems but unfortunately pushes it back to 2018. For existing systems, ARB should require that owners and operators conduct testing by a date certain that is earlier than September 1, 2017.

Furthermore, for existing separator and tank systems, the draft rule requires that by January 1, 2019, owners or operators of a system "with an annual emission rate greater than 10 metric tons per years of methane shall control the emissions from the separator and tank system and uncontrolled gauge tanks located upstream" with the use of a vapor collection system. §95668(a)(6). As with the deadline for flash analysis testing, ARB should require that owners and operators control emissions at an earlier date. As drafted, the rule would allow existing separator and tank systems that are currently emitting methane at a rate greater than 10 metric tons per year to wait almost two and a half years from now before controlling those emissions. This delay is unwarranted and the timeline for flash analysis testing and installation of a vapor collection system should be accelerated.

In previously submitted comments, we expressed concern that the prior version of the draft regulation may allow new vessels to operate without any emission controls for the first year of operation. The latest draft rule also clarifies the timing for new systems: "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." § 95668(a)(4) (emphasis added). The rule also clarifies that beginning January 1, 2018, owners or operators of new systems with an annual emission rate greater than 10 metric tons per year of methane must control the emissions with the use of a vapor collection system *within 180 days* of conducting flash analysis testing. 95668(a)(7) (emphasis added). Thus, under the proposed rule, a new system that exceeds the 10 metric tons per year threshold may not have to control those emissions for 270 days (approximately 9 months) after initial system startup.

Emissions are likely to be highest during the first year. Oil and gas well production generally declines during the first year of operation. Throughput of materials (oil, produced water, and other substances) in vessels tracks production, meaning that potential vessel emissions follow this curve as well. Thus, the draft regulation could allow emissions without control during a large portion of the time when those emissions will be highest.

As noted in our prior comments, other jurisdictions have successfully implemented regulations that require control of tanks much sooner after production begins at a well. Colorado requires operators to assess whether emissions will be significant from tanks – and if so, to control vessels from the date of initial production at the well. As noted in our prior comments, in crafting emission control requirements for vessels, the Colorado Air Pollution Control Division expressed concern that even allowing operators to wait *ninety days* after commencement of production to install controls on vessels would allow significant and avoidable air pollution.[136] Colorado determined that it would be cost effective to require controls to be installed on all crude oil and produced water tanks immediately, allowing operators to remove controls from a tank once testing demonstrated that the tank's uncontrolled emissions would fall below the applicable threshold. A presumption of control has the added benefit of providing operators with an incentive to test emissions promptly. ARB should follow Colorado's lead and assume that vessels require emission controls unless and until operators demonstrate otherwise.[137]

Alternately, US EPA requires that emissions from new and modified storage vessels that have potential to emit six tons of VOC or more per year must control emissions from those vessels by 60 days after the vessel goes in service.[138] We suggest that testing should, at the very least, be carried out within 30 days of initial production, and that ARB require that controls be in place within 60 days after initial production for tanks that have potential emissions above the threshold, in line with the federal standards (note that the federal standards have a different, VOC-based threshold than the draft ARB standard). However, we reiterate that ARB should first consider requiring control from the day of initial production when emissions from the tank can be anticipated to exceed 10 metric tons per year, in accordance with the Colorado approach.

ARB must also ensure that for new wells, the Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water properly assesses annual emissions. It is critical that operators assess potential emissions rapidly after operation of a tank begins, so that the tank can be controlled if needed. But ARB must also ensure that operators do not use a simple extrapolation of low production in the first days after production begins to conclude that potential emissions from the vessel will be less than the 10 metric tons per year threshold. Such extrapolation would be inappropriate because for new

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[136] Colorado Air Pollution Control Division, Final Economic Impact Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 5 (5 CCR 1001-9), pages 8-9 (Jan 30, 2014), available at ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Air%20Pollution%20Control%20Division%20(APCD)/APCD%20REB%20R7.finalEIA.pdf

[137] *See* February 2016 comments for a comparison of the requirements and timelines in the CARB draft rule to those in the Colorado methane rule.

[138] *See* 40 C.F.R. §60.5395(d)(1)(i). "For each Group 2 storage vessel affected facility [that is, vessels constructed after 12 April 2013], you must achieve the required emissions reductions by April 15, 2014, **or within 60 days after startup**, whichever is later" (emphasis added).

wells, particularly wells that were hydraulically fractured, production can rise dramatically over the initial weeks after production begins. ARB thus must ensure that operators use liquid throughput values in Equation 1 of Section 11 of the Test Procedure that are appropriate for yearly averages for new wells.

3. Provisions Requiring Clarification or Strengthening

ARB should also clarify or strengthen the following provisions:

- 95668(a)(5)(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." Please clarify how the ARB Executive Officer would determine whether the test results "reflect representative results of similar systems."
- 95668(a)(8): "If the results of three consecutive years of [flash analysis] 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." Testing once every five years is too infrequent to effectively determine if emissions have increased above 10 metric tons per year.
- 95668(a)(8)(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." The prior draft rule required recalculation of flash emissions with a *10 percent* increase in throughput, rather than 20 percent. The basis for this change is unclear since an increase in throughput of less than 20 percent could cause a meaningful increase in methane emissions. ARB should justify the 20 percent throughput threshold and if it cannot do so, require re-testing for any increase in throughput over that level tested in any of the prior testing years (or at the very least retain the 10 percent threshold). Furthermore, this provision should specify how soon after the increase of throughput must the flash emissions be recalculated. (The current draft appears to no longer include a provision specifically requiring flash analysis testing, record keeping and reporting to be conducted after adding a new well to the separator and tank system.)

VII. Liquids Unloading

We support ARB's approach with regards to Liquids Unloading emissions, either through capturing emissions using a vapor collection system, or measuring/calculating the volume of natural gas vented, and regularly reporting that volume. Joint commenters request the following in order to strengthen the liquids unloading proposal.

First, we request that ARB revise its proposed definition of "Liquids Unloading" by striking the phrase "with the use of pressurized natural gas."[139] Not all liquids unloading

[139] The current definition reads: "'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." § 95667(a)(28).

technologies use pressurized natural gas to remove liquids, so the proposed definition potentially creates a loophole in the control and reporting requirements.

We also urge ARB to make one improvement to the substantive control requirement and a few improvements to the reporting requirements in order to improve the protectiveness of the provision.

We urge ARB to follow the lead of Wyoming[140] and Colorado[141] and to require operators to keep personnel on site when conducting manual liquids unloading activities. This ensures that any venting that occurs is kept to a minimum. We anticipate that a prudent operator would follow this practice as a matter of course, as having personnel onsite to supervise manual liquids unloading not only ensures that emissions are minimized but also results in a more effective and safe operation. ARB should include this requirement to ensure that such a prudent practice is followed across the board.

In addition, we recommend several additions to the reporting requirements to allow ARB to closely monitor liquids unloading emissions and develop targeted standards in the future, should the need arise. Given the number of mitigation techniques available to operators, we expect that liquids can be unloaded without venting in the vast majority of cases. In this light, it is important that ARB use the reporting requirements to understand *why* operators vent wells during liquids unloading. ARB thus should require operators to report a number of well variables and conditions in the cases where venting does occur.

The current standard requires operators to annually report the following information in the cases where liquids unloading emissions are not captured:

- 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.)[142]

ARB should require operators to report a broader set of parameters and conditions while being more specific about the information required in the proposal. For each liquids unloading event at each well, ARB should require operators to report:

- Volume of gas vented and duration of venting event.
- Volume of liquids removed from well during venting event.
- Well Characteristics:
    - API Number
    - Spud date and completion date

[140] Wyoming DEQ, Oil and Gas Production Facilities, Ch. 6, Sec. 2 Permitting Guidance, 13, 19, 24 (May 2016), available at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf
[141] 5 C.C.R. 1001-9, § VII.H.1.b.
[142] Proposed § 95668 (g)(2).

    - A complete casing diagram, with all required depths reported as both measured depth and true vertical depth, including:
        - Ground elevation from sea level
        - Reference elevation (*i.e.* rig floor or Kelly bushing)
        - Well orientation: horizontal, vertical, or directional
        - Well depth
        - Sizes and weights of all casing, liners and tubing
        - Depths of shoes, stubs and liner tops
        - Depths of perforation intervals
        - Diameter and depth of hole
    - Liquids accumulation rate (barrels of water accumulated per day)
    - Gas production rate (before and after unloading event)
    - Sales line pressure
    - Shut-in pressure
    - Gas temperature at wellhead
- If liquids removal technology used, details of method:
    - Plunger lift: with or without smart automation
    - Foaming agent: type
    - Velocity tubing: diameter
    - Pumps
    - Gas lift
- If no liquids removal technology used:
    - The normal operating practice for venting the well: automatic vent timer or manual vent with or without monitoring
    - Vent time

We greatly appreciate the opportunity to comment on this important proposal and thank ARB for its leadership on this key climate and public health issue.

Respectfully submitted,

Darin Schroeder
David McCabe
Lesley Fleischman
Clean Air Task Force
18 Tremont St
Boston, MA 02108
dschroeder@catf.us

Tim O'Conner
Elizabeth Paranhos
Hillary Hull
Environmental Defense Fund
Offices in Los Angeles, San Francisco and Sacramento, California
Toconnor@edf.org

Briana Mordick
Meleah Geertsma
Natural Resources Defense Council
111 Sutter St., 21st Fl.
San Francisco, CA 94104
bmordick@nrdc.org

Elly Benson
85 Second Street, Second Floor
San Francisco, CA 94105
elly.benson@sierraclub.org