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Ms. Levine

Sierra Club, Clean Air Task Force, and Natural Resources Defense Council welcome the opportunity to provide comments on ARB's draft regulation for methane pollution from the oil and gas sectors. We offer these comments in response to the workshops held on April 27 and 29, 2015, and the draft regulatory language dated April 22, 2015.

As a general matter, we commend ARB for recognizing the severity of the problem of methane emissions from oil and gas production. Avoiding catastrophic climate change, and meeting California's greenhouse gas emission reduction obligations, will require reducing the millions of tons of carbon dioxide equivalent emitted annually by the California oil and gas industry.[1] Although the most effective way to reduce these emissions is to stop using and producing these fossil fuels in the first place, we strongly support ARB's efforts to enact strong regulation that will limit the methane emitted by oil and gas activity that does occur.

We also generally support the particular details of the draft regulation. Nonetheless, we identify three issues in which the regulation should be strengthened. ARB must require quarterly, if not more frequent, leak inspections; ARB must limit emissions from intermittent bleed pneumatic devices; and ARB must address emissions from vessels in their first year of operation.

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[1] We strongly encourage the use of the most recent available science regarding methane's impacts. As acknowledged in the Final State Regulatory Impact Report, when the Intergovernmental Panel on Climate Change's Fifth Assessment Report estimates of methane's potency are used, on the crucial 20 year timeframe, the greenhouse gas emissions from the oil and gas industry in California amount to more than three million tons per year of carbon dioxide equivalent.

A. LDAR Inspections

All Facilities Should Be Inspected at Least Quarterly. ARB should revise its draft regulations to require operators to perform LDAR inspections with consistent frequency, whether by means of a Method 21 approach or by use of an optical gas imaging (OGI) instrument. Specifically, ARB should require monthly facility-wide inspections. Alternatively, ARB could use a tiered system similar to the type that Colorado employs, where the largest facilities (i.e., those with a higher number of components that may leak) are required to perform the most frequent inspections. However, if ARB choses to take a tier-based approach to LDAR inspection, it should require inspections no less frequently than quarterly. As discussed more below, the costs imposed by a monthly (or quarterly) LDAR inspection requirement are reasonable independent of the size of the operator.

Four states require operators to inspect and repair equipment at many oil and gas facilities on at least a quarterly basis: Colorado[2], Wyoming[3], Pennsylvania[4] and Ohio.[5] The Colorado, Pennsylvania and Ohio requirements apply to components that leak methane as well as other air pollutants, such as volatile organic compounds. Colorado requires monthly inspections of some larger facilities. ARB's draft annual inspection option lags behind even some local California air district requirements that currently require quarterly inspections. While it is important that the ARB draft language would require inspection of all components in hydrocarbon service, not just those with a certain VOC content, and would apply statewide, the draft approach allowing allow only annual inspection of facilities of all sizes is insufficiently protective.

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[2] 5 C.C.R. § 1001-9 XVII.F (2014).

[3] See Wyoming Dept. of Environmental Quality (WDEQ), *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance*, at 22, 27 (2013), available at http://sgirt.webfactional.com/filesearch/content/Air%20Quality%20Division/Programs/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf (requiring quarterly instrument-based LDAR inspections in the Upper Green River Basin).

[4] See Pennsylvania Dept. of Environmental Protection, General Operating Permit 5, Section H, available at http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/gp/GP-5_2-25-2013.pdf (requiring quarterly LDAR inspections at gathering compressor stations and processing plants) (PA General Permit 5).

[5] See Ohio Environmental Protection Agency, General Permit 12.1(C)(5)(c)(2), available at http://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf (requiring quarterly LDAR at production sites) (Ohio General Permit 12.1); General Permit 12.2(C)(5)(c)(2), available at http://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.2_PTIOA20140403final.pdf (Ohio General Permit 12.2).

The frequency of inspections – both for Method 21 and OGI – is particularly important given ARB's current underestimation of the actual emissions that occur from statewide leaks. In its presentation, ARB reported 7,000 $MTCO_2e$ statewide, which, based on our own review of reported data, significantly underestimates the magnitude of leaks. To wit, our analysis of leak data reported to the US Greenhouse Gas Reporting Program (GHGRP) Subpart W from operators in California shows nearly 55,000 metric tons CO_2e in 2013.[6] Regulators and independent researchers have found that equipment malfunctions and poor maintenance can lead to very large emissions that are not reflected in emission inventories.[7] Operators cannot predict when a seal will loosen, when someone will leave a hatch open, or when a piece of equipment will fail from fatigue or corrosion; these types of malfunctions or mis-operation are a major source of emissions from oil and gas facilities.[8]

The economics of LDAR inspections and frequencies show that their costs are reasonable, and in some cases inspection and repair is profitable because of the value of the gas conserved by repairs. This reasonableness is based on two factors, laid out in detail in our recently published "Waste Not" report.[9] First, based on a study by Carbon Limits,[10] the cost to have an outside source perform the inspections

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[6] US Environmental Protection Agency. Greenhouse Gas Reporting Program (GHGRP). Petroleum and Natural Gas Systems. W_SOURCE_SUMMARY. Available at: http://www.epa.gov/enviro/facts/ghg/customized.html. (64,989 $MTCO_2e$ of leaks reported in GHGRP for oil and gas producing basins in California in 2013, but this is calculated using on a global warming potential of 25. We converted to a global warming potential of 21 to be consistent with ARB emissions estimates.)

[7] Brandt, A.R., et al. (2014) "Methane Leaks from North American Natural Gas Systems," Science, 343, 733.

[8] See for example, Texas Commission on Environmental Quality, "Public Health Risks in Shale Gas Development," Presentation at National Academies of Science Workshop on Risks of Unconventional Shale Gas Development, Washington DC, 30 May 2013, Slide 15. Available at: http://sites.nationalacademies.org/DBASSE/BECS/DBASSE_083487, which notes that most events causing citizen complaints are due to "human error or mechanical failures" that were "quickly remedied and could have been avoided through increased diligence on the part of the operator." See also 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*. Available at http://www.epa.gov/gasstar/documents/clearstone_II_03_2006.pdf, which found that found that 58% of emissions from the five gas plants surveyed came from just the top ten leaks at those plants. Some of the largest leaks encountered were from corrosion holes, a type of failure which can come about quickly and would not be predicted.

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

[10] Carbon Limits is an independent consultancy experienced in climate change policies and emission reduction project identification and development, particularly in the oil and gas sector.

an OGI survey itself is low – $400 to $1,200 depending on the size of the facility.[11] In fact, data complied by Colorado during a rulemaking effort similar to the one ARB is currently undertaking shows that such inspections cost between $820 and $860 per inspection. [12] For companies that can afford to purchase their own infrared camera, the Colorado rulemaking shows even lower costs: $263-$431 (Noble Energy) and $450-800 (Anadarko).[13] Similarly, Southwestern Energy has reported that LDAR surveys cost them less than a tenth of EPA's estimated implementation costs.[14] Thus, costs for OGI inspections are reasonable for both small and large producers.

Second, the costs to repair leaks, once identified, are almost – or even entirely – paid for by the value of the gas conserved by the repairs. The Carbon Limits study shows that 97 percent of the volume of leaks originated from leaks that result in a net profit once repaired.[15] Colorado predicted a similar percentage for well facilities only, estimating that 80 percent of repair costs for such facilities was covered by the value of the conserved gas. [16] And in Wyoming, Encana reported that the value of the gas conserved from LDAR inspections was overall greater than the repair costs. [17]

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[11] Carbon Limits, Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (2014), table 6. Available at: http://www.catf.us/resources/publications/view/198.

[12] Calculated from data in table 27 of CDPHE Cost-Benefit Analysis.

[13] Prehearing Statement of Noble Energy, Inc. and Anadarko Petroleum Coproration, *In the Matter of Proposed Revisions to Regulation Number 3, Parts A, B and C, Regulation Number 6, Part A, and Regulation Number 7.* 2/21/2014. Available at: 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.

[14] Jordan, Doug. "SWN Gas Capture Case Study and Methane Emission Initiatives." Natural Gas STAR Annual Implementation Workshop, San Antonio, 13 May 2014, slide 29. Available at: http://www.epa.gov/gasstar/documents/workshops/2014_AIW/Gas_Capture.pdf.

[15] Carbon Limits (2014) at 16. Carbon Limits found that the net present value (NPV) of repairs was positive for the vast majority of leaks and leak volume. Using a value of $4 / MCF for recovered gas, they found that 97% of leaking gas comes from leaks that have a positive repair NPV.

[16] Calculated from data in table 30 of CDPHE Cost-Benefit Analysis.

[17] Allen, Cindy, "CDPHE 2014 Rulemaking - Encana Rebuttal," 22 February 2014, available at: ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Encana%20Oil%20&%20Gas%20USA%20(Encana)/ENCANA%20REB%20(00299464).PDF.

The cost effectiveness of such inspections further justifies more frequent inspections. Colorado estimated that its tiered inspection rule will cost $1,259 per short ton of VOC abated at well sites.[18] Noble Energy actually predicted VOC abatement costs would be *one-tenth* of the cost predicted by Colorado.[19]

Because leaks emit more methane than VOC, the cost effectiveness of more frequent LDAR inspections will be even better. In fact, the Carbon Limits study found monthly surveys at production facilities and processing plants cost only $800 to $900 per ton of methane reduced.[20] Quarterly surveys cost less (below $300 per metric ton of avoided methane pollution), but also reduce emissions less in aggregate than monthly surveys.[21] Colorado's data for the costs of its rule, where inspection frequency is tiered to facility size, shows that the rule will have an overall net abatement cost of about $930 and $520 per metric ton of methane for well facilities and gathering compressor stations, respectively.[22] Additionally, ICF reports that quarterly LDAR surveys at transmission and storage compressor stations reduce methane emissions for only $118 per ton (not accounting for the value of gas kept in the system by repairing leaks).[23]

Other Concerns. ARB should revise its draft regulations to remove or clarify some of the exemptions for equipment listed in draft § 95213(i)(1) of the draft regulation.

First, the exemption for "One-half inch and smaller stainless steel tube fittings including those used for instrumentation" in draft § 95213(i)(1)(B) is unwarranted. Natural gas is typically handled at high pressures at these facilities

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[18] CDPHE Cost-Benefit Analysis, table 35.

[19] *Supra* n.13 (Noble/Andadrko)

[20] Carbon Limits (2014) at 22.

[21] *Id.* These estimates are conservative: the Carbon Limits study was largely based on facilities where regular LDAR programs had been in place for some time before the period of the study. As a result, the facilities in the Carbon Limits study were leaking less than typical U.S. facilities.

[22] The CDPHE Cost-Benefit Analysis reports net abatement costs of $474 and $805 per ton of methane and ethane assuming a $3.5/mcf value of saved gas, see tables 33 and 35. We recalculated using a $4/mcf value of saved gas and then converted this to cost per ton of methane abatement assuming that natural gas at production facilities has a ratio of methane to ethane of 6.2 by weight, in keeping with EPA documentation for the 2012 standards. See Brown, H.P, (2011), "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking," available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084.

[23] Calculated from data in table 3-4 of ICF International (2014).

and a very large volume of gas can move through a half-inch tube under these pressures. The tubing size would limit the emissions of a leak only for extremely large leaks; leaks on the size of tubing ARB would exempt can certainly emit enough methane and other pollutants to be harmful. Furthermore, given the speed with which components and instrumentation can be monitored using OGI, there is really no reason for this exemption.

We note that other statewide provisions for LDAR for oil and gas facilities, including the Colorado regulations and the Pennsylvania and Ohio Permit Exemptions and General Permits, have no similar exemption.[24]

Second, the exemption for, "components and piping located downstream from the point where crude oil or natural gas transfer of custody occurs" in draft § 95213(i)(1)(D) is unclear and could readily be misinterpreted to broadly exempt equipment or even facilities. It is not clear what the intention of this provision is. Natural gas goes through many custody transfers as it moves from production facilities, into gathering systems, into processing plants, into transmission pipelines, and into storage facilities. All of these facilities would be subject to these regulations in draft § 95211(a). However, we are concerned that some operators of midstream and downstream natural gas facilities, which are downstream of a "point of where natural gas transfer of custody occurs," may interpret this clause as exempting those facilities. Furthermore, on a single facility there may be custody transfers with significant equipment beyond that point but still within the facility. In some cases where the *natural gas* beyond the transfer point is owned by a different party than the facility operator, the *equipment and components* beyond the transfer point may still be owned by the facility operator. (Indeed, in general natural gas transmission firms do not own the gas that moves through their facilities.)

ARB must ensure that all equipment at all facilities is regularly inspected for leaks. We suggest that responsibility for LDAR should rest with the owner or operator of the equipment, rather than the firm with custody of the gas within the equipment.

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[24] See 5 CCR § 1001-9 XVII.F, XVII.A.5 and XVII.A.6 (2014) (definitions of "components" and "connectors"); Pennsylvania Dept. of Environmental Protection, Air Quality Permit Exemptions, Category 38, available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf; PA General Permit 5, Section H; and Ohio General Permits 12.1 and 12.2, sections (C)(5)(c)(2).

Third, the “unsafe to monitor” provision in draft § 95213(i)(1)(F) should be modified to reflect the practice of OGI. Because OGI allows meaningful inspection to be carried out at some distance from the monitored device, components can be safe to monitor with OGI that are not safe to monitor with Method 21.

At a minimum, CARB should revise draft § 95213(i)(1)(F) to read “Components which are unsafe to monitor using the chosen monitoring method and as documented in a safety manual or policy and with approval of the local air district.” ARB should also consider requiring operators to use OGI, if safe, for any components that are unsafe to monitor with Method 21.

ARB should also revise the provisions for repair of components found to be emitting with OGI in draft § 95213(i)(2)(B)(1). Operators should be given the option of simply repairing any leak identified with OGI within two calendar days and verifying the repair with OGI. Many leaks are simple to repair and repair of these leaks can be accomplished faster if quantification of the leak with Method 21 is not required as an intermediate step, as the draft regulation would require in draft § 95213(i)(2)(B)(1). Furthermore, this would incentivize the use of OGI. This will be even more important if ARB does not revise the draft regulation to require operators opting to use Method 21 to check for leaks on a quarterly basis; if ARB does not make that revision, it will be valuable for the regulation to incentivize operators to opt for use of OGI so that they are inspecting equipment on a quarterly basis. We note that this would also require minor modification of the reporting and recordkeeping requirements, which ARB can simply accomplish by defining any emissions detectable with OGI as a “leak above standard” for the purposes of Table 4 (Leak Detection and Repair Summary) in the reporting forms published as Appendix C of the ARB draft regulation.

B. Intermittent Bleed Pneumatic Devices

The draft regulation takes the important step of prohibiting venting of natural gas from pneumatic pumps and *continuous* venting from other (non-pump) pneumatic devices (often referred to as pneumatic controllers). Draft § 95213(g). The draft regulation does not limit emissions from *intermittent* bleed pneumatic controllers, however, despite the fact that these controllers are also a significant source of emissions. Indeed, facility owner reports to EPA’s GHGRP describe higher aggregate emissions from intermittent-bleed controllers than from high continuous bleed controllers. We summarize these issues below.

Intermittent-bleed pneumatic controllers are the source of a great deal of methane pollution. Oil and gas producers reported almost 780,000 metric tons of methane emissions nationwide from intermittent-bleed controllers to US EPA's GHGRP in 2013, far higher than the 194,000 metric tons of methane they reported from continuous-bleed controllers.[25] In California, oil and gas producers reported almost 3,900 tons of methane from intermittent-bleed controllers in 2013, while reporting no emissions at all from continuous-bleed controllers.[26]

As with other sources of emissions, the best control option is to use technologies that do not emit in the first place. Many high-emitting intermittent-bleed pneumatic controllers can be replaced with lower emitting, or even zero-emitting, equipment. EPA's 2012 OOOO standards require all pneumatic controllers at processing plants to be zero emitting.[27] As ARB has recognized, oil and gas production in California occurs largely is in areas with increased access to electric power, and compressed air can be used instead of natural gas to drive intermittent bleed pneumatic controllers, particularly where electric power is available. Even where venting natural gas-driven pneumatic controllers are used, lower-bleed intermittent pneumatic controllers are available. Properly designed intermittent bleed controllers can emit below 6 scfh in many applications.[28] The emissions factor for intermittent bleed pneumatics in natural gas transmission is 2.35 scfh,[29] well below 6 scfh. In a recent study of the methane abatement opportunities from oil and gas, ICF International estimated that 25% of high-emitting intermittent-bleed controllers in oil and gas production can be replaced with low-emitting devices.[30]

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[25] 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.

[26] Id.

[27] 40 C.F.R. § 60.5390(b)(1).

[28] In their comments on EPA's 2012 oil and gas rules, the American Petroleum Institute stated, "Achieving a bleed rate of < 6 SCF/hr with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller." In fact, API advocated intermittent-bleed devices to achieve the 6 scfh bleed rate, rather than continuous low-bleed devices. 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, and attached to this comment.

[29] 40 C.F.R. Pt. 98, subpart W, Table W-3.

[30] ICF International. (2014) "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," p. B-6. Available at: http://www.edf.org/sites/default/files/ methane_cost_curve_report.pdf.

In addition to using equipment that is not designed to bleed in the first place, emissions from intermittent pneumatic devices can be captured and controlled as CARB's proposal does for continuous-bleed pneumatic devices and pneumatic pumps. Draft § 95213(g)(1) and § 95213(g)(3). Wyoming requires that for any non-zero bleed pneumatic pumps at new or modified well pads, bleed emissions must be captured for sale or fuel, or controlled with an incinerator.[31] Wyoming requires *all* pneumatic controllers be low-emitting, regardless of whether they are continuous-bleed or intermittent-bleed, at new and modified facilities.[32]

In summary, evidence from industry, together with Wyoming's experience, shows that the control requirements draft in section 95213(g)(1) of the draft regulation could be applied to intermittent bleed controllers.

These requirements will produce abatement at a reasonable cost. We extensively discussed the cost effectiveness of controlling emissions from intermittent bleed pneumatics in comments we submitted to U.S. EPA regarding EPA's white papers on methane from oil and gas production[33] and in the "Waste Not" report published in December 2014.[34] As documented in the latter publication, we calculate that emissions from high-emitting intermittent bleed controllers can be reduced by converting to low-emitting controllers with cost savings to operators in the production segment, while converting production facilities to use compressed air instead of natural gas to drive pneumatic controllers has a net estimated cost of $750 per metric ton of avoided methane pollution.[35] Since most facilities will have VRUs or other emission controls, the costs of routing emissions from intermittent-bleed controllers to these control devices should be quite low (like the costs of routing emissions from continuous-bleed controllers to these control devices, as ARB proposes).

Finally, we encourage ARB to confirm that the draft regulation prohibits methane emissions from pneumatic *pumps* entirely (except for any residual

[31] See WDEQ (2013), Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance at 10.

[32] This requirement is applied to intermittent-bleed controllers in addition to continuous-bleed controllers (email from Mark Smith, WDEQ, to David McCabe, 22 September 2014), attached)

[33] Attached to Sierra Club's Sept. 10, 2014 comment to ARB and re-submitted with this filing. See pages 31-32.

[34] Attached to Clean Air Task Force and Sierra Club's January 9, 2015 comment to ARB and available online at http://www.catf.us/resources/publications/files/WasteNot.pdf.

[35] McCabe, David et al (2014) at Technical Appendix Section 2.

methane not destroyed by a vapor control device, if used). This is our understanding of section 95213(g)(3).

C. Vessel Emissions

We are concerned that the draft rule may allow vessels to operate without any emission controls for the first year of operation. Section 95213(a)(1)(A) provides owners and operators of crude oil, condensate, and produced water vessels a compliance option of undertaking annual flash analysis, with no requirement to actually control emissions unless this analysis demonstrates emissions in excess of ten metric tons of methane per year.

Because the measurement is only required annually, it appears that an operator may choose to conduct it on the last day of the first year of a tank's operation. Because section 95213(a)(1)(B) only requires control once methane emissions have been measured to exceed 10 metric tons per year, the draft regulation does not plainly require control within the first year.[36]

A regulation that had the effect of allowing vessels to operate without controls for the first year is especially problematic because emissions are likely to be highest during the first year. Oil and gas well production generally sharply declines during the first year of operation. Throughput of materials (oil, produced water, and other substances) in vessels obviously tracks production, meaning that potential vessel emissions follow this curve as well. Thus, the draft regulation not only has the effect of allowing uncontrolled vessel emissions for a year—it allows emissions without control during the time when those emissions will be highest.

Indeed, the Colorado Air Pollution Control Division, in crafting emission control requirements for vessels, 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.[37] Colorado determined that it

[36] ARB may also wish to specify how soon controls must be installed once emissions are measured to exceed ten metric tons.

[37] 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

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.

Although the Colorado analysis looked only at flares—the least favored control option—ARB should examine whether alternative controls would also be cost effective, as well as consider the benefits and drawbacks of flares as a fallback position. More broadly, ARB should follow Colorado's lead and assume that vessels require emission controls unless and until operators demonstrate otherwise.

D. Reciprocating Compressors

We support CARB's approach to require operators to either capture and control all emissions from rod packing on reciprocating compressors or to monitor rod packing emissions at the vent point and repair them when they exceed thresholds. However, we are concerned with the infrequent inspections required for large compressors (those rated at greater than 500 horsepower). As currently drafted, an operator of a small compressor (500 horsepower or less) has the option of either collecting the rod packing or seal vent gas and routing it to a sales gas system, fuel gas system, or vapor control device, or performing *quarterly* measurements and repair the rod packing or seal vents based on the measured concentration. However, operators of large compressors (over 500 horsepower) are only required to measure the flow rate *annually* if they opt out of the collection compliance option. CARB should remedy this discrepancy and require quarterly measurements for both large and small reciprocating compressors.

Additionally, we commend CARB for requiring measurement of the volumetric or mass flow rate from rod packing vents for larger compressors, as opposed to measuring the hydrocarbon concentration at the access port. Measuring the volumetric or mass flow rate from an access port with high volume sampling, bagging, or calibrated flow measuring instruments gives a real value for emissions, while hydrocarbon concentration is only weakly correlated with emissions[38]. Some leak-detection service providers routinely measure emissions from leaks with high

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[38] Clearstone Engineering *et al.* (2006) at 3.

volume samplers,[39] indicating that the cost of these measurements is quite reasonable. The routing of all emissions through and access port will make such measurements particularly accurate and feasible. Therefore, CARB should retain the requirement for measuring actual flow in this manner for large reciprocating compressors, but on a quarterly instead of annual basis, as discussed above. Further, CARB should consider requiring measurement of actual flow in this manner for smaller compressors, as opposed to measuring hydrocarbon concentration as currently drafted in draft § 95213(d). At a minimum CARB should seek comment and cost data on this approach for smaller compressors.

E. Liquids Unloading

CARB's requirements for liquids unloading of natural gas production wells allows, but does not require, the vented gas from the wellbore to be collected using a vapor collection system.

Liquids unloading emissions of methane and other pollutants can be very significant. Nationally, US EPA estimates that 259,000 metric tons of methane were vented during liquids unloading in 2013.[40] Currently venting emissions from liquids unloading in California that are reported to US EPA's GHGRP are small, but it is important to note that situation could change over time. The need to unload liquids from wells changes (generally increasing) over time as wells age, and as new wells are drilled in new formations, they may have more tendency to fill up with formation liquids than the current population of wells in California. We also note that practices vary greatly among well owners: some have track records of managing their wells to minimize venting during liquids unloading, while others do not.[41] If a group of wells in California changes ownership, management practice for those wells may change and new operators may choose to vent more methane from them. In short, while emissions are currently low from liquids unloading in California, this could change dramatically. With no federal standards for emissions

[39] Carbon Limits (2014) at 10.

40 See US EPA (2015), Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013, Annex 3, at Table A-149, available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

41 See Vaidyanathan, Gayathri (2014), Who are the Big Ten in the carbon pollution business? ClimateWire, 6 October 2014, available online at: http://www.eenews.net/climatewire/stories/1060006912/.

of methane from liquids unloading, CARB must ensure that California liquids unloading emissions will remain low by regulating this practice.

As we have discussed in our "Waste Not" report, there are a suite of cost-effective techniques to reduce or eliminate emissions of methane and other pollutants during liquids unloading.[42] CARB should require operators to utilize these techniques to reduce or eliminate the need to vent. At a bare minimum, CARB should require operators to utilize best management practices to reduce emissions from liquids unloading, and to have personnel on-site while any well is being vented, as Colorado[43] and Wyoming[44] require. CARB should seek comment on the feasibility of *requiring* capture of all venting emissions during liquids unloading.

CARB should maintain the requirement in the draft regulation to measure and report any venting emissions resulting from liquids unloading. CARB should additionally require that operators report the measures they have taken to minimize venting during liquids unloading. CARB should also seek comment on requiring reporting of the volumes of gas *captured* by operators.

F. Other Matters

The applicability of the draft regulation to natural gas gathering facilities should be made explicit by adding the word "gathering" so that Draft § 95211(a)(1)(A) reads, "Onshore and offshore crude oil and natural gas production, gathering, processing, and storage." Alternatively, "Natural gas gathering" should be otherwise added to Draft § 95211(a)(1).

G. Conclusion

We reiterate that the draft regulation is a much-needed improvement over the status quo and an important step toward combatting the difficult problem of

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42 McCabe, David et al (2014) at 35-38.

43 5 C.C.R. § 1001-9 XVII.H (2014).

44 See Wyoming Dept. of Environmental Quality (2013) at 11.

greenhouse gas emissions from oil and gas operations. While we have identified several concerns and areas in which the draft regulation should be improved, we are confident that these concerns can be addressed and improvements implemented prior to the regulation's formal proposal. If ARB has any questions regarding these comments, please contact the undersigned.

Sincerely,

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