February 19, 2016
Jim Nyarady
Manager, Oil & Gas Section
California Air Resources Board
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Dear Mr. Nyarady:

Please accept these comments on behalf of Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council and Sierra Club. We greatly appreciate the opportunity to comment on the California Air Resources Board's ("CARB") draft regulation for methane pollution from oil and gas facilities. We commend CARB for proposing a strong draft that, in particular, directly regulates methane from new and existing sources, and applies to a broad suite of facilities across the natural gas supply chain. We are particularly supportive of those provisions that require, or prioritize, the capture of methane, over combustion, and the broad applicability of the leak detection and repair requirement to multiple pieces of equipment and components. That being said we believe there is room for improvement and offer below some suggestions to this end.

A. Leak Detection and Repair

We commend CARB on proposing that operators inspect facilities quarterly. As we have documented in prior comments, frequent inspections are critical to ensuring leaks and emissions are minimized and promptly remediated.[1] They are also highly cost effective.[2] We do, however, believe the leak detection and repair provisions can and should be improved. Specifically, we strongly recommend the following:

- While maintaining the quarterly inspection frequency in the draft proposal, remove the provisions allowing operators to adjust frequency based on the number or percentage of leaking components identified in prior surveys, which are not rationally tied to the emissions performance of a facility, and misaligns incentives for operators;
- Allow for the use of optical gas imaging and other equally effective advanced technologies to detect leaks. This, coupled with Method 21 compliant devices capable of quantifying methane, will ensure that inspections efficiently detect the full suite of leaking components at a site, while still quantifying emissions from leaking components.
- Remove the exemptions in Section 95669(e)(1), (6) and (4) and narrow the exemption in (8); and
- Decrease the lowest allowable leak threshold from 10,000 ppm to 500 ppm, consistent with other leading states.

[1] May 15 Letter to CARB from EDF; May 15 Letter to CARB from Sierra Club, et al.
[2] *Id*.

1. *Eliminate Provisions Allowing for Reduction in Inspection Frequency*

We strongly advise eliminating provisions allowing operators to adjust frequency based on the number or percentage of leaking components identified in prior surveys, neither of which is rationally tied to the future leak performance of a facility. Moreover, such an approach misaligns incentives for operators.

As we have explained in prior comments, studies suggest that past leak emissions are not a good predictor of future leak emissions given the prominent role that improperly functioning equipment, poorly maintained equipment, and other random events play in overall leak emissions.[3] Numerous studies have found that leaks, in particular very large leaks or "super emitters," are largely unpredictable and shift over time. In particular, a series of studies undertaken in the Barnett Shale found that abnormal operating conditions, such as improperly functioning equipment, could occur at different points in time across facilities.[4] As a result, one of the study's authors concluded that inspections need "to be conducted on an ongoing basis" and "across the entire population of production sites."[5] Accordingly, we recommend that CARB propose an LDAR standard based on fixed frequencies.

Data from operators collected as part of Colorado's rulemaking further supports a fixed inspection requirement. Colorado's recently adopted leak detection and repair program requires that operators inspect for leaks at all but the smallest sites on a continuous annual, quarterly, or monthly basis.[6] 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."[7] Encana's data shows that while the largest reductions in VOC emissions occur in the first year of an LDAR program, operators continue to find leaks during every subsequent survey because leaks re-occur on an ongoing basis at facilities.[8] This pattern was independently confirmed in supplementary analysis carried out by Carbon Limits on leak inspection data from a number of

[3] May 15 Letter to CARB from EDF.

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

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

[6] 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014).

[7] 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.

[8] *Id*. at 10-11.

well production facilities and compressor stations.[9] Carbon Limits found that inspectors continued to find leaks in frequent repeat inspections on the same facility. Additionally, Carbon Limits found that the cost-effectiveness of the leak inspections, expressed in dollars per metric ton of VOC abatement, did not significantly rise over several years after regulations were put in place requiring LDAR at facilities in Alberta.

CARB's proposal creates perverse incentives by rewarding operators for failing to identify harmful leaks. This is not a hypothetical concern. A 2007 report by EPA found "significant widespread non-compliance with [LDAR] regulations" at petroleum refineries and other facilities.[10] EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions."[11] 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.[12]

We strongly recommend that CARB maintain the quarterly inspection frequency and remove provisions allowing operators to reduce frequency based on the percentage of leaking components identified in prior surveys. However, if CARB retains the provisions that allow for decreased inspections, we urge CARB to strengthen these by adding a provision that explicitly prohibits a decrease in monitoring if the facility is in violation of any aspect of the LDAR provisions, and requires a return to quarterly at those facilities conducting annual surveys upon the finding of a violation of any of the the LDAR provisions. This is the approach taken by Ventura County, San Joaquin Valley, and Santa Barbara air districts, and we maintain this is an important element to ensuring that reductions in frequency only occur at those facilities in compliance with the CARB rule.[13]

2. *CARB Should Allow for the Use of OGI and other Emerging Technologies Demonstrated to be Equally or More Effective, yet Less Costly, than Method 21.*

Optical gas imaging (OGI) systems have rapidly advanced to the forefront of leak detection technology, primarily because of the speed and comprehensiveness with which these technologies can detect leaks, as well as other important advantages over Method 21 or non-instrument based methods. In addition, the methane leak detection landscape is innovating

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[9] Colorado Department of Public Health and Environment. Index of /apc/aqcc/Oil & Gas 021914-022314/REBUTTAL STATEMENTS, EXHIBITS & ALT PROPOSAL REVISIONS/Conservation Group. Supplemental Testimony of David McCabe. Pg 734-736. Available at: ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Conservation%20Group/Conservation%20Groups%20-%20REB%20Exhibits.pdf.

[10] U.S. EPA, "Leak Detection and Repair: A Best Practice Guide," October 2007. Pg 1. Available at http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf.

[11] *Id.* at 23.

[12] *Id.*

[13] Ventura County Air Pollution Control District R. 74.10.D.8.b and 74.10.9; San Joaquin Valley Air Pollution Control District R. 4409.5.2.9 and 4409 5.2.10; Santa Barbara County Air Pollution Control District R. 331.F.2.c.

rapidly and we urge CARB to include an alternative compliance pathway that allows operators to use methods demonstrated to be equally or more effective at detecting methane leaks as Method 21 or OGI. Importantly, these benefits not only enhance the effectiveness of inspections in detecting leaks, but also reduce costs. Coupled with Method 21, OGI offers an efficient, comprehensive method to detect, quantify and help repair leaks:

- **Speed.** Optical gas imaging can be used to quickly and comprehensively scan an entire facility for leaks, accurately detecting almost any leaking equipment from safe vantage points. The Colorado Air Pollution Control Division estimates operators can scan a facility for leaks twice as quickly using an IR camera as they can using a Method 21 compliant device.[14] Some suggest that this is a conservative estimate of the time savings associated with the use of IR cameras, and that IR camera scans can be performed even more efficiently.[15] BLM estimates OGI can identify up to 2,100 components per hour while portable analyzer can only identify 30-40.[16] A recent presentation by Target Emission Services similarly notes that OGI is capable of surveying 1000-5000 components per day versus only 250-600 using Method 21.[17]
- **Comprehensive Inspection.** Moreover, optical gas imaging technology with infrared cameras is proven to enable efficient and accurate site-level assessments, including difficult to access components.[18] A clear illustration of this is that operators can detect leaks atop storage tanks using an IR camera that would otherwise go undetected unless an inspector climbed to the top of the tank.[19] As we have previously noted, thief hatches are a very significant source of leaks, as documented by various EPA Region 8 and Colorado inspections and enforcement actions.[20] This allows open thief hatches or other similar leaks to be promptly addressed once detected, without requiring an inspector to climb the tank on every leak survey. OGI allows operators to safely but effectively monitor components and equipment that may be unsafe to monitor with Method 21, and also

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[14] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) at 20, on file with EDF.

[15] ICF International, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," March 2014, at 3-10 to 3-11, available at https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf..

[16] U.S. Bureau of Land Management, Regulatory Impact Analysis for: Revisions to 43 CFR 3100, 3600 and Additions of 43 CFR 3178 and 43 CFR 3179, at 103, available at http://www.blm.gov/style/medialib/blm/wo/Communications_Directorate/public_affairs/news_release_attachments.Par.11216.File.dat/VF%20Regulatory%20Impact%20Analysis.pdf

[17] Target Emission Services. "LDAR Case Study: Comparison of Conventional Method 21 vs. Alternative Work Practices (Optical Gas Imaging)." (Hereinafter "Target Presentation"). Presentation at 2015 Gas Technology Institute Conference. Slide 8. Available at: http://www.gastechnology.org/CH4/Documents/13-Terence-Trefiak-CH4-Presentation-Oct2015.pdf.

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

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

[20] May 2015 Letter to CARB from EDF.

allows operators to detect leaks such as pinhole corrosion leaks in tanks, which operators are very unlikely to find with Method 21.

- **Accuracy and Efficacy.** Although technologies such as OGI do not currently quantify leaks, detection is of primary importance since most leaks are cost effective to repair once detected.[21] The quantitative comparisons that exist indicate that OGI is as effective as Method 21 in detecting all but the smallest leaks.[22] There is also data indicating that OGI can be more accurate for identifying the source of specific leaks.[23]
- **Compliance Monitoring and Enforcement**. OGI technologies allow operators to record and save videos of leaks. These records can help CARB or district inspectors confirm compliance with the LDAR requirements. While we urge CARB to remove the provisions allowing operators to decrease inspection frequency based on past performance, if these provisions remain, records of the leaks detected will become even more important and strict recordkeeping requirements should be adopted.

The use of OGI-based LDAR programs is a central feature of many leading and federal state standards. Five states – Colorado, Pennsylvania, Ohio, Utah and Wyoming – have adopted LDAR requirements for oil and gas facilities that allow the use of OGI instruments as a means of compliance.[24] Since 2011, Subpart W of EPA's Greenhouse Gas Reporting Program has allowed the use of OGI cameras to detect leaking components at above-ground facilities in natural gas processing, transmission, storage, and distribution, as well as LNG import/export facilities.[25] EPA and the Bureau of Land Management's recent proposals to limit pollution from oil and natural gas facilities both propose to allow for the use of OGI as the primary leak detection method.[26]

Many leading operators have also deployed OGI to help detect and repair leaks. Companies such as Shell, Anadarko Petroleum Corporation, and Noble Energy have indicated that they are utilizing infrared cameras for leak detection and repair purposes.[27] More specifically, Jonah

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[21] Letter from Jonah Energy LLC to Steven A. Dietrich, Administrator, Wyoming Department of Environmental Quality, Dec. 10, 2014 at 2 (discussing its voluntary LDAR program and stating that "the estimated gas savings from the repair of leaks identified exceeded the labor and materials cost of repairing the identified leaks."), on file with EDF; Carbon Limits, *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras*, CL-13-27 (Mar. 2014), *available at* http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf, at 16.

[22] EDF, Oil and Natural Gas Sector Leaks Peer Review Responses of Environmental Defense Fund, June 16, 2014 at 15-16; Target Presentation, supra note 17.

[23] Target Presentation, supra note 17.

[24] Co. Dep't of Pub. Health & Env't Reg. No. 7 (5 CCR 1001-9), See 5 C.C.R. § 1001-9 XVIII (2009). Available at https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=2772&fileName=5%20CCR%201001-9; Pa. Dep't of Envtl. Prot., General Permit for Natural Gas Compression and/or Processing Facilities (GP-5) Section H (1/2015); Ohio Envtl. Prot. Agency, General Permit 12.1(C)(5)(c)(2), 12.2(C)(5)(c)(2); Wyo. Dep't of Envtl. Quality, Oil and Gas Production Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised Sept. 2013); Utah Department of Environmental Quality, Division of Air Quality, Approval Order: General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery, II.B.10 (June 5, 2014).

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

[26] 80 FR 56593, 56596 (Sept. 18,2015); 81 FR 6616, 6647 (Feb. 8, 2016)

[27] EDF, Oil and Natural Gas Sector Leaks Peer Review Responses of Environmental Defense Fund, June 16, 2014 at 9.

Energy's Enhanced Direct Inspection & Maintenance (EDI&M) Program in Wyoming has been ongoing for the last five and a half years, employing a *monthly* leak detection and repair program using instrument-based surveys (IR camera technology). This program has resulted in over 16,000 inspections and thousands of repaired leaks identified by IR camera technology and a reported overall control effectiveness in excess of 75%.[28]

We are aware that Air Districts with existing inspection and maintenance programs require quantification of leaks. To the extent that CARB retains the requirement in the proposal that operators quantify leaks, we urge allowing operators the flexibility to couple their OGI inspections with a device capable of quantification. This would take advantage of many of the benefits of OGI while also ensuring quantification. Under this approach, operators would be required to first scan the facility with OGI, thus ensuring that difficult or unsafe to monitor components are scanned. Operators would then only be required to measure the leaks detected with the OGI camera. Since OGI operators can conduct OGI inspections more quickly than Method 21, this approach would result in a lower overall inspection time and therefore inspection costs, and still ensure that any detected leaks are quantified. Colorado allows operators to utilize this approach.[29]

As we have previously indicated, the methane leak detection technology landscape is advancing rapidly and the draft rule should support such innovation. Accordingly, we strongly urge the agency to allow operators to utilize approved devices other than Method 21 and OGI that have been demonstrated to be equally or more effective at detecting methane leaks. This is the approach allowed in Colorado.

3. *LDAR Exemptions Should be Removed or Narrowed to Improve the Protectiveness of the Rule and Increase Emission Reductions*

The LDAR provisions contain numerous exemptions that undermine the protectiveness of the rule and are not supported by LDAR requirements adopted or proposed in other jurisdictions. To ensure that this LDAR program results in the greatest degree of emission reduction feasible, we suggest removing or narrowing the following exemptions:

- Section 95669(e)(1). This provision exempts "components at a facility upstream of a transfer of custody meter used exclusively for the delivery of commercial quality natural gas to the facility." We understand that this exemption is intended to exempt the facility receiving commercial quality natural gas from responsibility for conducting LDAR on components that handle gas that does not belong to them. The problem with this approach is that it leaves components with the potential to leak unregulated. Regardless of who owns the gas, all components at facilities listed in Section 95666 should be subject to LDAR if the rule is to achieve the maximum feasible emission reductions. No other state with an LDAR program, nor the local District inspection and maintenance programs in California, contain this exemption. We urge CARB to remove this overly broad exemption, or otherwise clarify what entity is responsible for addressing leaks from the components identified in Section 95669, if it is not the entity receiving the commercial quality natural gas.

[28] Jonah Energy LLC, presentation at the WCCA Spring Meeting, May 8, 2015, on file with EDF.
[29] 5 C.C.R. § 1001-9 XVII.F.6.e.

- Section 95669(e)(6). This provision exempts "components and piping located downstream from the point where crude oil, condensate, or natural gas transfer custody occurs, including components and piping located outside the facility boundaries of natural gas compressor stations and underground storage facilities." Like the exemption in Section 95669(e)(1), this exemption is overly broad and threatens to exempt components located at numerous facilities. No other state with an LDAR program, nor the local District inspection and maintenance programs in California, contain this exemption. Custody transfer occurs at numerous points between the production, gathering and boosting, processing, storage and transmission segments, and therefore there are countless components potentially exempt under this provision. We urge CARB to remove this provision, or narrowly cabin it to certain limited, clear instances where CARB explains the basis for this exemption.

- Section 95669(e)(4). This provision exempts "one-half inch and smaller stainless steel tube fitting including those used for instrumentation. No other state LDAR program contains this exemption. Nor does the South Coast Air District inspection and maintenance rule 1173. We are not aware of any data that indicates that these types of fittings do not leak. In fact, to the contrary, other local Air District inspection and maintenance rules require these types of fittings to be included in LDAR unless demonstrated to be leak free.[30] We urge CARB to remove this exemption, or at a minimum, only allow it if operators demonstrate such fitting to be leak free.

- Section 95669(e)(8). This provision exempts components that are "unsafe to monitor when conducting Method 21 measurements and as documented in a safety manual or policy approved by the ARB Executive Officer." First off, we note that if CARB were to allow the use of OGI, the need for and use of this exemption would be significantly lessened, as operators can scan many components that may be unsafe to monitor using Method 21 (see above). Second, while we understand the need for safety exceptions, such exceptions should be narrowly tailored. We thus recommend that CARB require unsafe to monitor components be inspected within a certain timeframe. This is the approach taken by a number of the local Air Districts. Ventura County Air District requires operators inspect unsafe to monitor components at least once a year[31] and San Joaquin Valley requires such components be inspected "during each turnaround" or within two years of the date when five major leaks within a year have been detected, whichever is sooner.[32] We urge CARB to include similar provisions in its rule, specifically requiring inspection of such components at least every 6 months, during each turnaround, or when the component becomes safe to inspect, whichever happens earliest.

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[30] Ventura County Air Pollution Control District R. 74.10.G.2.b; San Joaquin Valley Air Pollution Control District R.4409.4.2.10; Santa Barbara County Air Pollution Control District R. 331.B.c.
[31] Ventura County Air Pollution Control District R. 74.10.D.5.a
[32] San Joaquin Valley Air Pollution Control District R.4409.5.3.7.6

4. *CARB Should Require All Leaks of 500 ppm be Repaired Upon Rule Implementation*

The proposal sets the lowest leak threshold at 10,000 ppm for the first year of the rule's implementation, 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.[33] U.S. EPA uses a leak threshold of 500 ppm for a number LDAR requirements for new facilities under NSPS Subpart OOOO.[34] We therefore urge CARB to lower the initial leak threshold to 500 ppm to be consistent with these other states and EPA to reflect what is technically feasible.

B. Pneumatic Devices and Pumps

We believe that CARB intends to regulate pneumatic devices in the following ways:

- Prohibit venting of natural gas from *continuous*-bleed pneumatic devices and pumps after 1 January 2018, as provided for in §§ 95668(f)(3) and (6);
- Include continuous-bleed, intermittent bleed pneumatic devices and pneumatic pumps in LDAR, as provided for in §§ 95668(f)(3)-(5); and
- Prohibit intermittent bleed devices from venting natural gas when not actuating after January 1, 2018, as provided for in § 95668(f)(4).

We commend CARB for proposing these provisions. No other jurisdiction prohibits venting from new continuous bleed devices or 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 malfunctioning intermittent and continuous-bleed devices and pumps.

1. *CARB Should Phase Out Existing Low-Bleed Continuous Devices*

That said, for continuous-bleed pneumatic devices, the draft regulation is significantly weaker than the 22 April 2015 draft regulation. We understand the proposal as allowing for the use of continuous-bleed pneumatic devices installed before 1 January 2015, provided operators adhere to the monitoring provisions in draft § 95668(f)(2), which requires operators to regularly check that these devices are not emitting more than six standard cubic feet per hour (scfh), and to 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.

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[33] 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.

[34] See 77 F.R. at 49,498.

As we detailed in our May 2015 comments, there are numerous ways to eliminate emissions from pneumatic devices that bleed natural gas to the atmosphere.[35] 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,[36] and EPA presumes that most operators will use compressed air systems to comply with this regulation.[37] For sites with numerous pneumatic devices, compressed air is a cost-effective and feasible approach to eliminate emissions from pneumatic devices – including any intermittent-bleed devices on site, and also most pneumatic pumps – especially when electric power is readily available. Oil and gas production in California occurs largely in areas with increased access to electric power. Many centralized production sites and compressor stations have numerous pneumatic devices.

Other "zero-bleed" technologies exist beyond compressed air to eliminate emissions from pneumatic devices. These include:

- generating low-cost electric power on-site which can be used to power electrical valve controllers and actuators, or potentially to compress air, including devices which generate electricity from compressor waste heat;

- solar / battery systems which can be used with electric controllers and actuators; and

- "closed-loop" actuator systems which use natural gas to control and actuate valves but capture that gas on the low-pressure side of a system so it is not vented.

These systems are described in more detail and documented in our comments to US EPA on Proposed NSPS Subpart OOOOa.[38]

In addition to using equipment that is not designed to bleed in the first place, emissions from pneumatic devices can be captured and utilized, sold, or controlled, as CARB's proposal recognizes. These options apply well to the "low-bleed" continuous-bleed pneumatic devices that CARB's proposal would grandfather. Since many of these devices are on sites that have, or will have, a vapor collection system, the cost of connecting a device to the vapor collection system is very low.

We thus recommend that CARB remove the provision allowing "low-bleed" continuous-bleed pneumatic devices that were in operation on 1 January 2015 to continue operating. If CARB concludes that such devices must be allowed to continue venting gas into the atmosphere, despite the numerous options operators have to eliminate these emissions, CARB 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.

2. *Control Emissions from Intermittent-bleed Pneumatic Devices*

CARB has significantly strengthened its proposal for intermittent-bleed pneumatic devices, by adding specific testing requirements to ensure that these devices do not leak gas into the air when

[35] May 15, 2015 CATF et al Comments to CARB at 8-9.
[36] 40 C.F.R. § 60.5390(b)(1).
[37] See EPA, TSD for the Proposed NSPS Subpart OOOO, 5-22 (July 2011).
[38] Dec. 4 CATF et al, Comments to EPA on Proposed OOOOa at 90-91, Ex 1.

not actuating. Draft § 95668(f)(4). However, we reiterate our concern that, beyond this provision, the draft regulation, like the April 2015 draft, 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 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).[39] In California, oil and gas producers reported over 4,100 tons of methane in 2014 from intermittent-bleed devices, while reporting no emissions at all from continuous-bleed devices.[40] Alarmingly, reported emissions from intermittent-bleed devices are increasing, both nationwide and in California.[41]

Similar to continuous-bleed devices, there are numerous options to limit or eliminate emissions from intermittent-bleed pneumatic devices. Many high-emitting intermittent-bleed pneumatic controllers can be replaced with lower emitting, or even zero-emitting, equipment. The zero-emitting technologies described above can all be applied to intermittent-bleed devices, and in the case of compressed air systems, a single system can readily be used to run a mix of continuous-bleed and intermittent-bleed devices. 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.[42] The emissions factor for intermittent bleed pneumatics in natural gas transmission is 2.35 scfh,[43] 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.[44] Wyoming requires *all* pneumatic controllers to be low emitting, regardless of whether they are continuous-bleed or intermittent-bleed, at new and modified facilities.[45]

While CARB's proposal would reduce emissions from intermittent-bleed devices by ensuring that devices that leak continuously are fixed or replaced, the emissions from properly operating devices will remain high without additional standards.

It may be useful to consider that not all intermittent-bleed devices actuate frequently – but some actuate very frequently, and therefore emit large amounts of natural gas. For example, Allen *et*

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[39] 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.

[40] *Id*.

[41] *Id.*

[42] 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.

[43] 40 C.F.R. Pt. 98, subpart W, Table W-3.

[44] 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.

[45] 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), Ex. 2.

al. (2015) observed that controllers for emergency shut-off devices made up 12 percent of the population of controllers that they studied.[46] These devices will actuate very rarely, if at all. It may be reasonable to exclude some intermittent-bleed devices from control requirements for vent gas, if operators can demonstrate that actuation is very uncommon. (If facilities have instrument air installed, however, the costs of connecting that air supply to every intermittent-bleed controller are very low, and in general that should be required.)

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 fifty times while sampled.[47] These devices can emit at high levels – five of the forty highest emitting devices studied by Allen *et al*. (2015) are intermittent-bleed devices that were assessed to be operating properly.[48] Devices with specific functions, such as level controllers on separators, are likely to actuate frequently.

While specific treatment of intermittent-bleed devices that very rarely actuate may be warranted, the fact that some controllers very rarely actuate cannot be used to justify inaction for the entire class of intermittent-bleed controllers.[49] Since there are available approaches to avoid these emissions, CARB must issue appropriate standards to address emissions from intermittent-bleed controllers that are operating properly (not continuously emitting) and that have high emissions.

We suggest that CARB require emissions from intermittent-bleed devices be routed to a vapor collection system; if such a system is not available or operators can demonstrate that such routing is not feasible, operators must ensure that the intermittent-bleed device does not emit natural gas continuously or emit over six scfh, as is required in Wyoming.[50]

As we discussed and documented in our May 2015 comments, these requirements will produce abatement at a reasonable cost. This is particularly true for California, where most facilities will have vapor collection systems, so the costs of routing emissions from intermittent-bleed devices to these systems should be quite low (like the costs of routing emissions from continuous-bleed controllers to these control devices, as ARB proposes).

Finally, we commend CARB's proposal to require capture of all emissions from natural gas-driven pneumatic pumps.

C. Compressors

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[46] Allen D.T. *et al.* (2015), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environ. Sci. Technol*. 49, 633−640.
[47] Derived from analysis of table S4-1 in Allen *et al.* (2015) supplemental information.
[48] See Allen *et al*. (2015), Supporting Information, section S-8. 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 forty highest emitting controllers – are clearly intermittent devices which were assessed to be "operating as expected."
[49] Since some intermittent-bleed devices actuate very rarely, their emissions are low. These devices bring the average emissions factor for intermittent-bleed devices down.
[50] Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6(f).

1. 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. We commend CARB's draft proposal for requiring control of rod packing emissions from compressors at wellpads, which EPA has failed to require or propose for even new equipment to date, and for requiring measurement of actual emissions from "midstream" compressors – those at natural gas gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities.

However, the draft regulation should be strengthened. Since even new, properly installed rod packing seals allow some natural gas to escape past the seals, emissions from reciprocating compressors – even those that are monitored closely – are inevitable if the natural gas that escapes is not captured and directed to a vapor collection system (VCS). Therefore directing gas to a VCS should be required whenever possible. The alternative approach of monitoring emissions and requiring repair when emissions rise above a threshold should only apply when directing gas to a VCS is somehow not feasible. Even if used to control emissions with a vapor control device as described in draft §95668(c)(3) – (c)(4), instead of directing vapors to a sales, fuel, or reinjection line, collecting vapors with a VCS is superior to monitor and repair. CARB should strengthen the draft by requiring the use of a VCS whenever feasible.

The draft standards magnify this problem by only requiring annual monitoring for midstream compressors, which would be regulated under draft §95668(d)(2), when those compressors do not have vapor collection systems in place. Furthermore, the emissions standard for these compressors – two standard cubic feet per minute (scfm) per cylinder (draft §95668(d)(2)(E)) – is much higher than appropriate, since rod packing replacement can cost-effectively reduce emissions at levels far below 2 scfm per cylinder, as we show below.

We commend CARB for requiring measurement of the volumetric or mass flow rate from rod packing vents for midstream 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.[51] Some leak-detection service providers routinely measure emissions from leaks with high volume samplers, indicating that the cost of these measurements is quite reasonable.[52] The routing of all emissions through an access port will make such measurements particularly accurate and feasible. Therefore, CARB should retain the requirement for measuring actual flow in this manner for midstream reciprocating compressors, but on a quarterly instead of annual basis, as discussed above. If measurements are only required on an annual basis, as in the current draft, two problems arise. First, elevated emissions can and will continue over a longer period than if quarterly measurements are required. Second, the lax annual requirement encourages operators

[51] 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*, at 3. Available at http://www.epa.gov/gasstar/documents/clearstone_II_03_2006.pdf.

[52] Carbon Limits (2014), supra note 21 at 10.

of midstream compressors to monitor emissions rather than direct natural gas from reciprocating compressor seals to a VCS.

Further, CARB must strengthen the proposal by reducing the threshold at which repair of rod packing is required. Draft §95668(d)(2)(E) requires repair or replacement of rod packing when emissions per cylinder reach two scfm. However, since the natural gas that escapes from rod packing and is vented to the air is a salable product, and repair / replacement of rod packing keeps more natural gas in the system and therefore increases revenues for operators, repair / replacement of rod packing is cost-effective when emissions are far lower than 2 scfm. In comments we recently filed on US EPA's 2015 proposed New Source Performance Standard Subpart OOOOa, we used US EPA figures for the costs of rod packing replacement to show that replacement is cost-effective when emissions per cylinder reach 20 to 25 standard cubic feet *per hour*, over a factor of four lower than the 2 scfm threshold in draft §95668(d)(2)(E).[53] For example, using cost figures from US EPA documents (converted to 2015 dollars) and a $4 per MCF price of natural gas, we showed that the net abatement cost of replacing rod packing when emissions per cylinder reach 20 scf per hour is $538 per short ton of avoided methane pollution; if the threshold were 25 scf per hour, the net cost would drip to $232 per short ton of abated methane.[54] Accordingly, CARB must reduce the threshold at which replacement or repair of rod packing is required. It is important to consider that operators have other options for control; specifically, the option of using a vapor collection system. Indeed, commercial systems to direct rod packing emissions to fuel systems for compressors are available,[55] and in general these emissions can be routed to a VCS which directs gas into a sales line such as a vapor recovery unit on a tank. We also 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% control.[56]

Finally, CARB should consider requiring measurement of actual flow, in the manner required for midstream compressors, for compressors at wellpads and other oil and gas production sites, as opposed to measuring hydrocarbon concentration as currently required in draft § 95668(d)(1)(B). At a minimum CARB should seek comment and cost data on this approach for these compressors. Wellpad compressors can be large and, given the low cost of actual emissions measurements, it is not appropriate to require the less accurate concentration measurement at all of these compressors.

2. *Centrifugal Compressors*

We believe that the approach taken by CARB in the previous (22 April 2015) draft of the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities was more appropriate that the approach taken in the current draft. The April 2015 draft would have required operators of centrifugal compressors with wet seals to "collect the wet seal vent gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device." April 2015 Draft at § 95213(f)(1)(B). In contrast, the

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[53] Joint comments at 101-102.
[54] *Id* at 102.
[55] *Id* at 98.
[56] Ohio EPA, General Permit 17.1 Template, C.(1)(b)(1)(d), available at http://epa.ohio.gov/dapc/genpermit/permitsec.aspx

current Draft Proposal allows operators of centrifugal compressors with wet seals to opt out of installing a vapor collection system, and instead to monitor emissions from the wet seals and, if they rise above three scfm, to "minimize" emissions and after several years, to install dry seals. Draft regulation at § 95668(e)(3) – (e)(8). This is an odd approach.

First, it is generally very feasible and cost effective to install vapor collection systems that route wet seal degassing emissions to the suction side of the compressor, another beneficial use, or a control device. EPA has published literature through its Natural Gas STAR program describing how these systems — consisting of seal oil/gas separators, demisters/filters for both high and low-quality gas, and necessary piping and instrumentation — are cost effective and can largely eliminate vented gas from wet seal compressors.[57] EPA literature presents four different options for using gas that is captured through these devices: 1) return it to compressor suction; 2) route high-pressure gas to a combustion turbine for electricity generation; 3) route low-pressure gas to a heater or boiler to use as fuel; and 4) send the captured gas to a control device.[58] EPA notes that at least one operator has configured its system to use all four of these options.[59] Based on experience from about one hundred installations, BP has reported that systems that return seal gas to compressor suction (the first option) are "simple, broadly flexible, and reliable," and generate "positive cash flow in less than a month."[60] EPA requires that operators of new and modified wet-seal centrifugal compressors at gathering and boosting compressor stations and gas processing plants use these vapor collection systems to capture seal oil degassing vapors and route emissions to a process or 95% control,[61] and has proposed extending this requirement to new and modified transmission and storage segment wet-seal centrifugal compressors.[62]

Second, according to US EPA, "Methane emissions from wet seals typically range from 40 to 200 standard cubic feet per minute."[63] The minimum of this range is an order of magnitude above the threshold above which CARB would require operators to "minimize" emissions. Draft regulation at § 95668(e)(6) – (e)(7). Simply put, wet seal centrifugal compressors without vapor collection systems in place cannot meet this standard.

Recognizing this, many operators may choose to simply install vapor collection systems, which is a comparatively simple modification, not requiring years of lead time. However, in addition to increasing the complexity of the rule, the option to monitor and "minimize" emissions instead of installing a vapor collection system may be detrimental. First, since the word "minimize" in draft § 95668(e)(7) is not defined, and a wet seal unit operating normally typically emits at least 40 scfm, the provision may be interpreted by some operators as allowing them to operate wet

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

[58] *Id*. at 3.

[59] *Id.*

[60] *Id.*

[61] 40 C.F.R. § 60.5380.

[62] Proposed 40 C.F.R. § 60.5380a (80 F.R. 56,593.)

[63] See EPA, *Replacing Wet Seals with Dry Seals in Centrifugal Compressors* (2006), at 1. *Available at:* http://www3.epa.gov/gasstar/documents/ll_wetseals.pdf.

seal compressors uncontrolled, emitting well over three scfm, until January 1, 2020. Second, it is not clear how the critical component provision in draft 95668(e)(8) will operate, and whether operators of designated-critical wet seal centrifugal compressors will enact controls.

As such, CARB should revert to the simpler and clearer approach to wet seal centrifugal compressors in the April 2015 Draft regulation.

Finally, CARB should ensure that components on driver engines and compressors for *dry seal* centrifugal compressors are subject to the LDAR provisions of §95669. We believe that this would reflect CARB's intent. However, since 95668(e)(2) specifically requires this for wet seal compressors but the draft is silent on dry seal compressors in this regard, we are concerned that some operators may misinterpret the draft regulation as not requiring LDAR for dry seal compressors.

D. Crude Oil, Condensate, and Produced Water Separation and Storage

CARB should clarify and tighten deadlines related to both commencement of annual flash analysis testing and installation of vapor collection systems (where the measured annual flash emission rate is greater than 10 metric tons per year).

1. Testing Should Occur Earlier and Controls be Installed Sooner

We remain concerned that the draft rule may allow new vessels to operate without any emission controls for the first year of operation. Section 95668(a)(4) provides that owners and operators of new and existing separators and tank systems that are not controlled for emissions with the use of a vapor collection system must conduct annual flash analysis testing of the crude oil, condensate, or produced water – with no requirement to actually control emissions unless this analysis demonstrates emissions in excess of ten metric tons of methane per year. (Section 95668(a)(2)(B) exempts tanks from the requirements of this subsection entirely if they are "used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from any newly constructed well for up to 30 calendar days following initial production," so long as the tank is not used to circulate liquids from a well that has been subject to a well stimulation treatment.)

Section 95668(a)(4) clarifies that this annual flash analysis testing must be conducted "[b]eginning January 1, 2017 and by no later than September 1, 2017." Though the draft states that this requirement applies to "new and existing" systems, it appears to apply to separator and tanks systems that are in place prior to January 1, 2017 (and possibly to those that become operational between January 1, 2017 and September 1, 2017). For such systems, CARB should require that owners and operators conduct testing by a date certain that is earlier than September 1, 2017. Furthermore, CARB should clarify that this means that the first test must be done prior to that date (as opposed to that date commencing a year-long period during which testing may occur).

For separator and tank systems that start operation between January 1 and September 1, 2017, or after September 1, 2017, it is unclear when flash analysis testing must commence. For example, because the measurement is only required annually, it is possible that an owner or operator of a system that starts operation after September 1, 2017 may choose to conduct testing on the last day of the first year of a tank's operation. Because section 95668(a)(5) 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.

CARB should also specify how soon controls must be installed once emissions are measured in excess of 10 metric tons. Section 95668(a)(5) specifies that the requirement to control emissions begins January 1, 2018 ("Beginning January 1, 2018, owners or operators of separator and tank systems with a measured annual flash emission rate greater than 10 metric tons per year of methane shall control the emissions from the separator and tank system with the use of a vapor collection system as specified in section 95668(c)"). It is unclear when vapor collection systems must be installed (i.e., how soon after the measurement greater than 10 metric tons), particularly for systems that exceed the 10 metric tons per year threshold after January 1, 2018. Section 95668(a)(8) further states that flash analysis testing "shall be conducted *within one calendar year* of adding a new well to the separator and tank system since the time of previous flash analysis testing" (emphasis added). With a full year to conduct testing and no firm date to realize control of the vessel, we are concerned that operators may delay installation for long periods of time *after* testing, leading to excessive periods without control.

Other jurisdictions have successfully implemented regulations that require control of tanks in the months after production begins at a well. 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.[64] As discussed below, 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. In light of these precedents, CARB's proposal is clearly insufficiently protective.

As noted in our prior comments, a regulation that had the effect of allowing vessels to operate without controls for the first year is 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 tracks production, meaning that potential vessel emissions follow this curve as well. Thus, the draft regulation may not only have the effect of allowing uncontrolled vessel emissions for a year—it could allow emissions without control during the time when those emissions will be highest. This concern is heightened because operators may be incentivized to delay testing until the end of the year, because if production has dropped enough to reduce potential emissions below the 10 metric ton per year threshold, the vessel will not need control.

As noted in our May 2015 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.[65] Colorado determined that it would be cost effective to

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[64] 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.

[65] 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

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.

At bare minimum, CARB should clearly indicate 1) when annual flash analysis testing must commence (including for systems that become operational after the dates specified in 95668(a)(4)), and 2) for systems with a measured annual flash emission rater greater than 10 metric tons per year, the mandatory timeline for installing a vapor collection system.

We suggest that testing should be carried out within 30 days of initial production, and that CARB 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 CARB standard). CARB should also 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.

CARB 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. CARB 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 ton per year threshold. Such extrapolation would be inappropriate because for new wells, particularly wells that were hydraulically fractured, production can rise dramatically over the initial weeks after production begins. CARB 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.

2. *Provisions Requiring Clarification or Strengthening*

CARB should also clarify or strengthen the following provisions:

- 95668(a)(4)(D): "Demonstrate that the results of the flash analysis testing are representative of the crude oil, condensate, and produced water processed or stored in the separator and tank system. 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." It is unclear how the owner or operator would demonstrate that the test results are representative, or how the ARB Executive Officer would determine whether the test results "reflect representative results of similar systems."
- 95668(a)(7): "…. If the results of flash analysis testing are less than or equal to 10 metric tons per year of methane using three consecutive years of test results 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)(9): "Flash emissions shall be recalculated if the annual crude oil, condensate, or produced water throughput increases by more than 10 percent since the time of the previous flash analysis testing" (provided that the increase in throughput is not a result of adding a new well to the separator and tank system which requires additional flash analysis testing as specified in section 95668(a)(8)). This provision should specify how soon after the throughput increase the flash emissions must be recalculated.

3. Comparison of CARB Proposal to Colorado Requirements

The following section compares the requirements and timelines in the CARB draft rule to those in the Colorado methane rule (emphasis added):

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control and monitoring requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of storage tanks with uncontrolled actual emissions of VOCs ***equal to or greater than six (6) tons per year based on a rolling twelve month total*** *must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.*

XVII.C.1.b.(i) Control requirements of Section XVII.C.1.b. must be achieved in accordance with the following schedule:

XVII.C.1.b.(i)(a) A storage tank constructed on or after May 1, 2014, must be in compliance ***within ninety (90) days of the date that the storage tank commences operation****.*

XVII.C.1.b.(i)(b) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(i)(c) A storage tank not otherwise subject to Sections XVII.C.1.b.(i)(a) or XVII.C.1.b.(i)(b) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must be in compliance ***within sixty (60) days of discovery of the emissions increase****.*

XVII.C.1.c. Control requirements within ninety (90) days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities must collect and control emissions by routing emissions to operating air pollution control equipment ***during the first ninety (90) calendar days after the date of first production****. The air pollution control equipment must achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. This control requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after the date of first production.*

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c.(i) may be removed at any time after the first ninety (90) calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank will be below the threshold in Section XVII.C.1.b.

…

XVII.C.2. Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section XVII.C.2.b.(ii).

…

XVII.C.2.b.(ii) Owners or operators must achieve the requirements of Sections XVII.C.2.a. and XVII.C.2.b. and begin implementing the required approved instrument monitoring method in accordance with the following schedule:

XVII.C.2.b.(ii)(a) A storage tank constructed on or after May 1, 2014, must comply with the requirements of Section XVII.C.2.a. ***by the date the storage tank commences operation****. The storage tank must comply with Section XVII.C.2.b. and implement the approved instrument monitoring method inspections* ***within ninety (90) days of the date that the storage tank commences operation****.*

XVII.C.2.b.(ii)(b) A storage tank constructed before May 1, 2014, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. by May 1, 2015. Approved instrument monitoring method inspections must begin within ninety (90) days of the Phase-In Schedule in Table 1, or within thirty

(30) days for storage tanks with uncontrolled actual VOC emissions greater than 50 tons per year.

XVII.C.2.b.(ii)(c) A storage tank not otherwise subject to Sections XVII.C.2.b.(ii)(a) or XVII.C.2.b.(ii)(b) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. and implement the required approved instrument monitoring method inspections ***within sixty (60) days of discovery of the emissions increase***

E. Catastrophic Leaks

We commend CARB for considering this important issue, particularly in light of the disastrous natural gas leak at the Aliso Canyon underground storage facility and the regulatory gap it exposed. Given the current regulatory framework applicable to California's fourteen underground gas storage facilities and the age and condition of the state's oil and gas infrastructure, the potential for large and catastrophic leaks is a critical safety and environmental problem. We also note, however, that this is a complicated new undertaking with many complex topics that must be carefully considered. While we urge CARB to move forward with developing a mitigation framework to address any future major leaks as expeditiously as possible, we request that ARB not delay the current rulemaking schedule in order to do so.

In developing mitigation requirements, we request that CARB consider the following:

- Regulatory Authority. CARB should reserve for itself broad authority to ensure emissions from large and catastrophic leaks are fully mitigated. Criteria for determining which leaks are subject to mitigation requirements should not be narrowly limited to predetermined emissions thresholds. Site-specific conditions should be taken into account when determining whether any particular leak qualifies for regulation under this new program, including but not limited to volume, proximity to sensitive receptors, potential health and environmental threats, leak duration, and others.
- Accounting Framework for Quantifying Leaks. CARB must develop a scientifically rigorous framework for quantifying leak volume. The exact accounting method may vary depending on the nature of the leak and site-specific conditions and CARB should therefore ensure that the framework provides sufficient flexibility to respond to different leak sources and types, while also relying on proven and scientifically defensible measurement and estimation methods.
- Preventative Measures. CARB should prioritize measures that could help prevent large or catastrophic leaks from occurring in the first place, for example requiring facilities to develop an assessment of the threat of such leaks and steps that could be taken to minimize those threats. To the extent that agencies other than ARB have jurisdiction over the sorts of preventative measures that could prevent large or catastrophic leaks from occurring, CARB should coordinate with those agencies to help ensure they have everything they need to put such measures in place.

- Mitigation Requirements. Detailed and specific criteria need to be developed that can serve as the foundation for required mitigation of large and/or catastrophic leaks. At a minimum, the following should be addressed:
    - Stringency. CARB should require that leaks be repaired as expeditiously as possible and that the entire volume of leaked methane be remediated.
    - Accuracy. As discussed above, a site-specific and scientifically rigorous method must be developed to determine the total leak volume.
    - Credibility. CARB itself, in addition to local air districts, should approve and independently verify reductions using scientifically proven methods.
- Penalties and Compensation. CARB should consider options such as fines based, for example, on the volume and duration of the leak, and compensation for people negatively affected by the leak. It should also ensure that costs associated with the leak will not be passed on to ratepayers.
- Emergency Authorization. ARB should also consider including provisions analogous to section 303 of the federal Clean Air Act, 42 U.S.C. § 7603, which authorizes EPA to bring suit in federal court to stop or prevent pollution that poses and imminent and substantial endangerment to the public health and welfare, or to issue enforceable orders where necessary. An analogous provision in CARB's regulations could grant APCDs/AQMDs or any other appropriate agency authority to bring suits against, or issue binding orders to, any source that is responsible for a large or catastrophic leak limited in time and scope to measures that would remove any imminent and substantial endangerment posed by the leak.
- Notification Procedures. The rules should include specific timeframes in which leaks must be reported to CARB, local air districts, other regulatory agencies with jurisdiction over the leaking facility, potentially impacted members of the public, and other relevant stakeholders.
- Emergency Planning. CARB should require facilities to prepare and submit emergency response plans for large and catastrophic leaks. These plans should be reviewed and approved in conjunction with other regulatory agencies with jurisdiction over the facilities, (e.g. DOGGR, CPUC, etc.). Such plans should be periodically reviewed and updated at a fixed frequency and/or when necessitated by material changes in operations at the subject facility.

We greatly appreciate the opportunity to comment on this important proposal and look forward to working with CARB as it develops the next iteration of this regulation.

Respectfully submitted,

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