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Re: Environmental Defense Fund Comments on Proposed Regulation Order Article 3: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities: Part II of Comments.

Dear Ms. Scheehle and Mr. Fischer:

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF") on the California Air Resources Board ("CARB") proposal to regulate greenhouse gas emissions from oil and gas facilities. This is EDF's second set of comments and addresses the additional proposed requirements in the April 22nd draft. EDF submitted comments pertaining to the leak detection and repair requirements on May 15th.

I. Storage Tanks

Storage tanks are the second largest source of methane covered by the proposed regulation. Importantly, however, investigations of storage tank emissions indicate that actual emissions are often much greater than what is reported in inventories, or calculated using flash analysis.[1] A combination of frequent instrument based inspections, adequately designed storage tank and emission control equipment, and rigorous capture and control requirements, are necessary to reduce storage tank emissions. Fortunately, such cost effective solutions exist. We urge CARB to ensure that its storage tank requirements reflect the most protective requirements required by local air districts and other leading states.

We commend CARB for proposing a requirement that prioritizes the capture and recovery of natural gas emissions over control and destruction technologies for those vessels with an annual emission rate of at least 10 metric tons of methane, or who voluntarily opt to control emissions.

[1] *See e.g.*, 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.

The primary component of natural gas is methane, which is a valuable economic resource. Recovering methane can result in additional natural gas sales and revenue for operators and boost severance tax and royalty payments to local and state governments while also reducing harmful pollution. We are pleased, therefore, that the proposed requirement in Section 95213(c) requires operators to utilize a vapor collection system (VCS) that directs collected vapors from storage vessels and circulation tanks to a sales gas system, fuel gas system or underground injection well. We also support the proposed requirement that operators may only utilize an existing vapor control device (such as a flare) if they can demonstrate to the local air districts that the collected vapors cannot be directed to the sales gas or fuel gas system or injected into an underground well and that directing the vapors to a vapor control device (VCD) will not result in an exceedance of the existing device's permitted emission limits.[2]

Similarly, we support the proposed regulation's approach for those operators who wish to utilize an existing VCD to control emissions. Under the regulation, those operators must make a demonstration to the local air districts that their VCD achieves a minimum vapor control efficiency and meets all local, state and federal requirements. If located in an ozone nonattainment area, operators must obtain local air district approval in order to use a non-destructive VCD and ensure that it will not result in emissions of nitrogen oxides above local air district requirements. Alternatively, operators may use a destructive VCD provided it does not require supplemental fuel gas to operate or result in emissions of nitrogen oxides above local air district requirements.[3]

A. Primary and Secondary Vessels

While we strongly support the prioritization of capture technologies over control and destruction technologies, we suggest certain improvements to this requirement to further enhance the pollution reductions. First, we suggest CARB specify when operators must install controls if the annual flash testing analysis reveals annual emissions of 10 metric tons of methane or greater. Appendix A only specifies when operators must submit the results of the testing to CARB but neither the draft rule nor Appendix make it clear when controls must be installed. We suggest CARB require controls be installed upon the first date of production for a new well or upon the date that an existing well is modified. This is consistent with requirements in place in Wyoming and Colorado.[4]

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[2] Proposed Regulation Order Article 3: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, Section 95213(c)(2).
[3] *Id*. at Section 95213(c)(4).
[4] Wyoming Department of Environmental Quality, Oil and Gas Production Facilities Permitting Guidance (Sept. 2013), 14 (WY Permitting Guidance) (controls must be installed at all multi-well pads upon the first date of production or modification), available at http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf; Colorado requires controls on all storage tanks with at least 1.5 tons of VOCs to install controls within the first 90 days after the date of first production, 5 C.C.R. 1001-9, CO Reg. 7, § XVII.C.1.c., and requires operators whose storage tank emissions have increased to 5 tons per year of VOCs to install controls within 60 days of discovery of the emissions increase. *Id*. at. XVII.C.1.b.(i).(c).

Second, we suggest that CARB require all new VCD meet a 98% or better vapor destruction efficiency and be equipped with an auto-igniter – instead of the current requirement for 95% destruction efficiency. This will align CARB's requirements with those of other leading states. Colorado requires that combustion devices used to control hydrocarbons at tanks, glycol dehydrators, and gas "coming off a separator, [or] produced during normal operation" must have a design destruction efficiency of at least 98% for hydrocarbons.[5] Wyoming similarly requires that combustion devices used to control emissions from tanks, separation vessels, glycol dehydrators, and pneumatic pumps meet a 98% control requirement.[6] North Dakota also requires operators use control devices that achieve at least a 98% destruction removal efficiency for VOCs to control emissions from glycol dehydrators and tanks with the potential to emit greater than 20 tons of VOCs annually at production facilities in the Bakken Pool.[7]

Third, we suggest CARB add a requirement that operators certify that their VCS are adequately sized in order to capture, convey and control emissions. Recent inspections by EPA and the state of Colorado have revealed that inadequately designed and operated storage tank vapor control systems can result in very significant emissions.[8] Equipment must be designed to handle the pressure of liquids when transferred from separators to tanks. If the tank vapor system is not adequately sized to handle the peak surge of flash emissions that occur when pressurized liquids dump to the atmospheric storage tanks, then flash emissions do not make it to the control devices. Rather, access points on tanks designed to only open during emergencies or maintenance, such as thief hatches and pressure relief valves, open, releasing uncontrolled flash emissions to the atmosphere. In inspections of 99 storage tank facilities in Colorado's Denver-Julesburg basin in 2012, the Colorado Air Pollution Control Division and EPA found that emissions were not making it to their intended control devices at 60% of the facilities. These inspections formed the basis for a $73 million dollar settlement between Noble Energy, the U.S. EPA and the state of Colorado.[9]

Recently implemented rules in Colorado address this problem. Per the Colorado rules, operators must develop a Storage Tank Emission Management System plan. The purpose of this plan is to ensure that the storage tank facility is designed and operated properly to ensure that tanks operate without venting from access points during normal operation. Per the plan requirements operators must:

- Monitor for venting using approved instrument monitoring methods and sensory detection methods;
- Document any training undertaken by operators conducting the monitoring;
- Analyze the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;
- Identify the procedures to be employed to evaluate ongoing capture performance;

[5] 5 CCR 1001-9 §§ XVII.C.1.c, XVII.D.3, XVII.G.
[6] Wyoming Permitting Guidance, 6-10 (requirements for statewide sources. Same control efficiency required for sources located in other parts of the state), Sept. 2013.
[7] https://www.ndhealth.gov/AQ/Policy/20110502Oil%20%20Gas%20Permitting%20Guidance.pdf.
[8] *Supra,* note 1.
[9] *Id*.

- Have in place a procedure to update the storage tank system if capture performance is found inadequate;
- Certify that they have complied with the requirement to evaluate the adequacy of their storage tank system.[10]

We urge CARB to consider adopting a similar requirement to prevent the types of emissions and rule violations that occurred in Colorado.

Lastly, as discussed in our May 15 comments, we strongly suggest CARB include <u>all</u> collection and control systems on tanks and vessels in the LDAR program. As discussed above, leaks and malfunctions can occur during both abnormal and normal operations, and routine inspections with modern leak detection equipment are a very effective way to identify and immediately mitigate such occurrences.

We also request CARB explain the basis for the 10 tpy of methane and 6 tpy of methane control applicability thresholds in the rule so that we can understand the basis for these specific limits, and offer our comments on the sufficiency of the standards in subsequent filings.

B. *Circulation Tanks*

We commend CARB for requiring that operators capture vapors from circulation tanks during well stimulation and support the requirement as written. As CARB is aware, there is a gap in the current federal rules for these sources in that EPA's reduced emission completion only applies to gas wells. However, leading states require, or, like CARB, have proposed to require, the capture and control of completion emissions from both oil and gas wells. We note below other state "green completion" or reduced emission completion requirements in order to provide support for CARB's proposed requirement.

Colorado requires operators of wells that are capable of producing "naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater" to utilize green completion practices.[11] These practices require operators route all "saleable" gas to a sales line as soon as practicable or conserve the gas by shutting in the well.[12] If gas capture is not feasible, operators must use best management practices to minimize emissions.[13]

Ohio has proposed to require all operators of hydraulically fractured wells, regardless of whether classified as an oil or a gas well, to control completion emissions using EPA's reduced emission completion requirements.[14]

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[10] 5 CCR 1001-9 §§, XVII.C.2.b.; XIX.N., Statement of Basis, Specific Statutory Authority, and Purpose (Feb. 23, 2014).
[11] COGCC R. § 805(B)(3)(A).
[12] COGCC R. § 805(B)(3)(B)(i).
[13] COGCC R. § 805(B)(3)(D).
[14] Ohio Environmental Protection Agency's proposal to add a permit-by-rule for "horizontal well completion operations to OH. ADMIN. CODE Ch. 3745-31-03(c)(2)(m) (2014).

Capturing, or combusting with high-efficiency flares, is highly cost effective. Relying on data from multiple sources (i.e., EPA Subpart W, production data from 4 basins, and the UT production study), EDF estimates a median cost effectiveness of $3,314/MT CH4 reduced, with a credit for gas savings.[15] For those instances where gathering infrastructure is unavailable, EDF estimates the use of high efficiency flares ranges from $19-$424 MT CH4 reduced.[16] The recent ICF report estimated the use of high efficiency flares to be $97/ MT CH4 reduced.[17]

II. **Reciprocating Compressors**

We support the proposed requirements that require capture or control of rod packing or seal vent gas from compressors. We also support the requirement to measure rod packing or seal vent emissions and to inspect routinely and repair leaks. However, these two requirements should not be proposed as alternative compliance pathways. While we agree that installation of a vapor collection system will ensure that leaks do not occur from rod packing and seal vents, the vapor collection system itself can still leak. Accordingly, operators who choose to install a vapor collection system must still be required to inspect the system for leaks on a quarterly basis. This should be done as part of the comprehensive LDAR program discussed in our May 15 comments. In addition, we suggest certain improvements to the compressor requirements to improve the overall methane reductions achievable.

First, we suggest CARB strengthen the requirements aimed at detecting and repairing leaks in sections 95213 (d)(3)-(4) and (e)(3)-(4). The proposal allows for annual inspections and repair of leaks above 2 standard cubic feet per minute at compressors over 500 rated horsepower. For smaller compressors, the proposal requires quarterly inspections and repair of leaks measured as total hydrocarbon concentrations in parts per million by volume.

As noted in our May 15 comments, quarterly inspections rather than annual should be required for all size compressors, rather than only for the smaller compressors as proposed. In addition, we suggest CARB allow operators to utilize an IR camera, a Method 21 device capable of detecting methane, or other approved device. If they utilize an IR camera, the leak standard requiring repair could be the flow rate proposed in section (e)(4). Alternatively, the total hydrocarbon concentration of 1,000 in parts per million by volume proposed could be the leak standard when operators use a device capable of quantification. Operators should have flexibility in choosing which type of device to use.

Secondly, we suggest CARB require the use of a VCS that routes emissions to the sales gas or fuel gas system, or underground injection well as the initial compliance pathway. Only where operators cannot capture and re-use or inject emissions should they be permitted to destroy them using a VCD. This is consistent with CARB's proposal to reduce methane

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[15] Peer Reviewed Responses of EDF "Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions And Associated Gas during Ongoing Production" (June 16, 2014).
[16] *Id*.
[17] ICF, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, (March 2014).

emissions from storage tanks in Section 95213(c), which we support.

Lastly, we suggest that the results of all reciprocating compressor inspections be subject to the LDAR recordkeeping and reporting requirements proposed in sections 95214(a)(6) and 95215(a)(4). Compliance monitoring is important to ensure leaks from all sized compressors are minimized given the fact that this source category is the largest CH_4 source in the inventory.

III. **Centrifugal Compressors**

We support the requirement to capture emissions using a vapor recovery system or to install dry seals. However, as with other provisions of the rule, there are several instances where the protectiveness of the rule could be improved.

First, as noted above, we suggest CARB require the use of a VCS that routes emissions to the sales gas or fuel gas system, or underground injection well as the initial compliance pathway.

Secondly, we suggest including the vapor collection system in LDAR inspections. As noted above, leaks can occur from the vapor collection system when the VCS is operating. In addition, when VCS systems fail and are not operating a sufficient negative pressure to effectively manage associated compressors, leaks from the compressor become more than just a possibility--they become likely. Therefore, it is not sufficient to require that operators route their wet seal gas vapor to the VCS. Operators must also ensure that the VCS is doing its job and collecting all vapors – and LDAR requirements are an important test.

Third, we suggest the addition of robust recordkeeping and reporting requirements to monitor and ensure compliance. Specifically, we suggest requiring that operators maintain records of any inspections and repairs of VCS or VCD used to capture or control seal vent emissions, or dates of installation of dry seals.

Lastly, we offer the following information as an example of potential future cost effective capture technologies. Per the ICF methane reduction opportunities report, emissions from wet-seal centrifugal compressors can be reduced by 95% using a wet degassing recovery system at a cost-effectiveness of only $11 per MT of CH_4 reduced without gas credit, and at a negative cost of $253 per MT of CH_4 reduced with credit for gas savings.[18] This process has not yet been demonstrated as a commercial retrofit, but the technology does exist to do so.

IV. **Pneumatic Controllers**

We commend ARB on a strong proposal to eliminate vapors from continuous vent devices. As noted in our May15 comments, in order to ensure that all vapors are captured and controlled by the vapor collection system, we urge ARB to include the VCS used to control

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[18] ICF International, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," (March 2014). We converted the $ per Mcf to $ per MT of CH_4 using standard conversion factors for the properties of methane.

pneumatic controller emissions in LDAR.

We support the requirement that intermittent pneumatic devices not leak when idle. However, we believe this must be coupled with frequent instrument inspections in order to ensure that this standard is met. Therefore, intermittent as well as continuous bleed pneumatic devices must be subject to LDAR. In addition, we suggest limiting emissions from intermittent bleed devices to a specific numeric standard. Wyoming, for example, requires both continuous and intermittent natural-gas driven pneumatic controllers to limit emissions to 6 standard cubic feet per hour, as demonstrated by manufacturer specifications.[19] We suggest CARB do the same as this will help ensure that intermittent device emissions are maintained to low levels and avoid regulatory vagueness which may lead to unneeded emissions.

V. **Pneumatic Pumps**

We support the requirement to prohibit venting from natural gas driven pneumatic pumps. There are multiple cost effective practices and technologies available to achieve the goal of zero pump emissions in addition to vapor capture. Specifically, according to Natural Gas Star Partner Reported Opportunities (PRO) information on converting natural gas-driven pumps, natural gas chemical pumps can be converted to instrument air pumps in the range of \$8 to \$76 per MT of CH_4 reduced without recovered gas credit, and a negative cost of \$143 to \$211 per MT of CH_4 reduced with credit for saved gas.[20] In addition to instrument air pumps, another alternative for natural gas pump replacement is electric pumps driven by solar energy, which can be implemented for \$150 per MT of CH_4 reduced without recovered gas credit, or a negative cost of \$69 per MT of CH_4 reduced with credit for saved gas.[21] Similarly, ICF estimated the cost effectiveness of replacing a natural gas pump with an electric pump as \$252 per MT of CH_4, or a negative cost of \$11 per MT of CH_4 assuming a credit for recovered gas.[22]

We have only one suggested improvement for this requirement, and that is, consistent with our statements above, to prioritize the capture and recovery of natural gas over its destruction when operators choose to collect vapors using a VCS.

VI. **Liquids Unloading**

We appreciate CARB's effort to encourage the capture or control of vented emissions during liquids unloading activities. The proposal, however, falls short of what is economically and technically achievable, and therefore fails to ensure the maximum emissions reductions possible. Rather than providing operators with the option of either controlling or measuring emissions, CARB should ensure this rule provides for the maximum protections from harmful

[19] Wyoming permitting guidance, at 11; Wyoming Department of Environmental Quality proposed changes to Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6, (adopted by Environmental Quality Council, May 19, hard copy on file with EDF.
[20] http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf.
[21] *Id*.
[22] *Supra* note 18.

methane emissions possible by requiring operators control emissions. Doing so is cost effective and achievable and would better align the CARB requirements with those promulgated in other leading states.

As CARB has recognized, there are a suite of technologies and practices available to reduce venting during liquids unloading events.[23] According to EPA, some such measures include plunger lift systems, artificial lifts, velocity tubing, and foaming agents.[24] Flaring is also an option. Implementing one or a combination of these available practices or technologies can reduce the amount of uncontrolled methane that operators vent during liquids unloading activities.

Leading states currently require that operators take steps to minimize venting during liquids unloading activities. In recognition of the suite of available practices and technologies that can be used to reduce venting, both Colorado and Wyoming require operators take steps to control liquids unloading emissions. Colorado requires "owners or operators use best management practices to minimize hydrocarbon emissions and the need for well venting associated with downhole well maintenance and liquids unloading" other than when necessary for safety."[25] Accordingly, operators must both attempt to unload liquids without venting, by, for example, using differential pressure to unload liquids.[26] And, if venting occurs, they must limit venting "to the maximum extent practicable."[27] In approving this requirement the Colorado Air Quality Control Commission found that "the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible…".[28]

Since 2010 Wyoming similarly has required that operators incorporate best management practices into permits in order to "minimize VOCs and HAPs to the extent practicable during venting associated with liquids unloading."[29] To help ensure that operators meet this requirement, Wyoming requires that personnel remain onsite during any manual venting episode. According to Wyoming regulators, this particular requirement has significantly helped reduce liquids unloading emissions.[30] Notably, Colorado now requires the same.[31]

Reports submitted to EPA, as well as the March ICF report, demonstrate that the primary technique for mitigation of methane emissions during liquids unloading, namely the use of plunger lift systems, is highly cost effective. Per ICF, installing plunger lift systems in gas wells, which reduces emissions by 90%, can be employed at a cost-effectiveness of $261 per MT of CH4 reduced without credit for recovered gas, and a negative cost of $2.60 per MT of CH4 reduced with credit for saved gas. According to EPA, Natural Gas STAR partners "have

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[23] ARB's Oil & Natural Gas Methane Regulation, Public Workshop, California Air Resources Board, Sacramento, California, 6 (December 9, 2014), http://www.arb.ca.gov/cc/oil-gas/meetings/Workshop_Presentation_12-9-14.pdf.
[24] EPA, Oil and Natural Gas Sector Liquids Unloading Process, April 2014, Section 3, available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415liquids.pdf.
[25] 5 CCR 1001-9 § XVII.H.1.
[26] *Id*. at § XVII.H.1H.1.a.
[27] *Id*. at § XVII.H.1H.1.b.
[28] *Id*. at XIX.N (Statement of Basis and Purpose).
[29] Wyoming Permitting Guidance, 10, 17, 21.
[30] Conversations with members of the Wyoming Air Division.
[31] *Id*. at § XVII.H.1H.1.b.

reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well by avoiding blowdowns. In addition, increased gas production following plunger lift installation has yielded total gas benefits of up to 18,250 Mcf per well, worth an estimated $127,750."[32] Plunger lifts pay for themselves in less than a year using gas prices as low as $3 per Mcf.[33]

EDF recently analyzed the cost effectiveness of using mobile or stationary flares to reduce emissions from wells that vented above a specific threshold during liquids unloadings. Measurement data obtained from 107 wells demonstrates that 16% of the wells accounted for 95% of the emissions. These wells vented at least 250 Mcf per year. Per EDF's analysis, utilizing high-efficiency flares with a combustion efficiency of 98% at wells above this threshold can cost effectively reduce emissions by 93% for average reduced of $140-$260 per ton of methane reduced. The range represents the difference in costs between using a stationary or mobile flare at three different types of wells, and a range of costs from low to high (See Table 1, Exhibit 1).

Of the 107 wells sampled that vented at least 250 Mcf during unloadings, the vast majority of venting occurred at wells that were equipped with an automatic plunger lift. Specifically, 65% of the venting occurred from these types of wells. The EDF analysis concluded that due to the greater frequency of unloading at wells equipped with automatic plunger lifts, it is more cost effective to install a stationary flare rather than use a mobile flare to control emissions. The average cost effectiveness of employing a stationary flare to reduce emissions at wells with automatic plunger lifts with emissions above 250 Mcf ranges from $100-$180 per ton of CH4 reduced. At the 250 Mcf methane threshold for automatic plunger lift wells, deploying stationary flares would reduce total measured emissions from all 107 wells in the dataset by 60%.

Wells that unload liquids manually with or without the use of a plunger lift account for the remainder of emissions from those wells that vent at rates of 250 Mcf per year or greater during liquids unloading activities. These types of wells vent less frequently than those equipped with automatic plunger lifts. To assess the cost effectiveness of using flares at these manually unloading wells, EDF assumed operators would either use a stationary of mobile flare. Specifically, those wells unloading only twenty times a year or less would use mobile flares while those manually unloaded wells that unloaded more frequently would use stationary flares. The average cost effectiveness of employing a combination of stationary and mobile flares at wells conducting manual unloading ranges from $110-$190 per ton of methane reduced. Deploying flares at those wells above the 250 Mcf threshold and conducting manual unloading would reduce total measured emissions from the 107 wells by 33%.

CARB has proposed a liquids unloading emission estimation equation in Appendix B. The equation appears to estimate the maximum potential emissions from an unloading event. We suggest that CARB also require operators specify the time of the well metered flowrate (FR) in the equation. This likely should be the flowrate after the unloading event since the pre-unloading flowrate will be very low.

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[32] EPA, Lessons Learned from Natural Gas STAR Partners: Installing Plunger Lift Systems in Gas Wells ("Plunger Lift Lessons Learned")(2006) at 1. Available at: http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.
[33] *Id*.

VII. Conclusion

We greatly appreciate the opportunity to comment on this draft regulation. We look forward to working with CARB to improve the draft as suggested above.

Sincerely,

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