Environmental Defense Fund and Pennsylvania Environmental Council Comments on Pennsylvania Department of Environmental Protection's Proposal to Amend Chapters 121 and 129 of the Pennsylvania Administrative Code– Control of VOC Emissions from Oil and Natural Gas Sources

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Introduction

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF") and Pennsylvania Environmental Council ("PEC") on the Pennsylvania Department of Environmental Protection's ("Department" or "DEP") proposal to amend Chapters 121 (relating to general provisions) and 129 (relating to standards for sources). We commend DEP for proposing requirements that address pollution from existing oil and gas sources. However, the proposal needs to be significantly strengthened in order to curb harmful methane emissions that contribute to climate change and volatile organic compounds that contribute to ground-level ozone and to fulfill the Governor's commitment to reducing methane from existing sources. As currently drafted, the proposal exempts the majority of wells across the Commonwealth from the operation of the regulation, leaving upwards of 484,00 tons of methane emissions on the table.[1] In addition, the DEP proposes to allow operators to decrease the frequency of LDAR inspections over time, increasing the risk that large, episodic leaks will go undetected and unrepaired for lengthy periods of time.

Two separate obligations require DEP undertake regulatory actions to control volatile organic compounds ("VOCs") and methane ("CH_4") emissions from existing oil and gas sources. First, in 2016 Governor Wolf committed to regulating methane from existing sources. And, as a member of the Ozone Transport Commission ("OTC"), DEP must include in its state implementation plan ("SIP") rules that implement "reasonably available control technology" ("RACT") to control VOCs from oil and gas sources covered by control techniques guidelines ("CTG").[2] The U.S. Environmental Protection Agency ("EPA") promulgated CTGs for oil and gas sources in October 2016,[3] triggering a statutory obligation for Pennsylvania to propose RACT for oil and gas sources.

We have included specific suggestions below that, if accepted, would lead to thousands of tons of additional methane and VOC reductions and would fulfill Governor Wolf's promise to reduce harmful methane emissions from Pennsylvania's oil and gas sector.

In 2016, Governor Wolf committed to reducing methane emissions from oil and gas sources as part of a strategy "to protect the environment and public health, reduce climate change, and help businesses reduce the waste of a valuable product…"[4] Per this commitment, the Governor directed the Department of Environmental Protection to develop "a regulation for existing sources" to reduce leaks at existing oil and natural gas facilities.[5] DEP similarly stated its intent to develop a regulation that establishes robust requirements for existing sources in the oil and natural gas industry and to institute best management practices for methane monitoring and leak detection and repair provisions aimed at controlling or preventing fugitive emissions from pipelines.[6]

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[1] EDF, Pennsylvania Low-producing Well Technical Analysis (Exhibit A).

[2] 42 U.S.C. § 7511c(b).

[3] Control Techniques Guidelines for the Oil and Natural Gas Industry, EPA 453/B-16-001, Office of Air Quality Planning and Standards, EPA, October 2016.

[4] Governor Wolf Announces New Methane Rules to Improve Air Quality, Reduce Industry Loss (Jan. 19, 2016).

[5] *Id*.

[6] PA DEP, *A Penn. Framework of Actions for Methane Reductions from the Oil and Gas Sector*, pp. 3, 5 (Jan. 19, 2016) (*available at* http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Methane/DEP%20Methane%20Strategy%201-19-2016%20PDF.pdf).

Moreover, in 2019, the Governor signed an Executive Order requiring the state to achieve a 26 percent reduction of net greenhouse gas emissions statewide by 2025 from 2005 levels, and an 80 percent reduction of net greenhouse gas emissions by 2050 from 2005 levels.[7] Reducing methane from existing oil and gas sources is critical to achieving these targets.

DEP estimates that the proposed rule will reduce methane emissions by 75,602 tons per year ("tpy").[8] More specifically, DEP estimates the control measures could reduce methane emissions by as much as 11,582 tpy from fugitive emissions components through the performance of quarterly leak detection and repair ("LDAR") inspections, by as much as 17 tpy from the installation of controls for storage vessels with actual emissions based on the Department's more stringent applicability thresholds, 2,583 tpy from pneumatic pumps, and 61,421 tpy from pneumatic controllers.[9] While these reductions represent an important step towards fulfilling the Governor's commitment to reducing methane from existing sources, DEP must do significantly more to fulfill the Governor's methane strategy and meet the state's greenhouse gas reduction goals.

Pennsylvania has authority to reduce methane emissions from existing sources

The Air Pollution Control Act ("APCA") provides authority for DEP to regulate methane as an air pollutant.[10] First, section 5 of the APCA provides DEP with broad authority "to adopt rules and regulations for the prevention, control, reduction and abatement of air pollution in this Commonwealth."[11] Methane is incontrovertibly an air pollutant under the Act. The APCA contains a capacious definition of "air pollutant" and air pollution.[12] The definitions in the APCA

[7] Executive Order 2019-01, Commonwealth Leadership in Addressing Climate Change and Promoting Energy Conservation and Sustainable Governance (Jan. 8, 2019).

[8] PA Bulletin, Doc. No. 20-684, p.8 (June 1, 2020).

[9] Proposed Preamble, Proposed Rulemaking Environmental Quality Board [25 PA. CODE CHS. 121 and 129], Control of VOC Emissions from Oil and Natural Gas Sources, 17-18 (Dec. 2019), (Hereinafter "Preamble") http://files.dep.state.pa.us/PublicParticipation/Public%20Participation%20Center/PubPartCenterPortalFiles/Environmental%20Quality%20Board/2019/December%2017/7-544_OG_CTG_Proposed/02_7-544_OG_CTG_Proposed_Preamble.pdf.

[10] 35 P.S. § 4003 (defining "air pollution" broadly as "The presence in the outdoor atmosphere of any form of contaminant, including, but not limited to, the discharging from stacks, chimneys, openings, buildings, structures, open fires, vehicles, processes or any other source of any smoke, soot, fly ash, dust, cinders, dirt, noxious or obnoxious acids, fumes, oxides, gases, vapors, odors, toxic, hazardous or radioactive substances, waste or any other matter in such place, manner or concentration inimical or which may be inimical to the public health, safety or welfare or which is or may be injurious to human, plant or animal life or to property or which unreasonably interferes with the comfortable enjoyment of life or property.

[11] Air Pollution Control Act (APCA) (35 P.S. § 4005(a)(1)).

[12] 35 P.S. § 4003 (defining air pollutant broadly as "Smoke, dust, fume, gas, odor, mist, radioactive substance, vapor, pollen or any combination thereof") cf to CAA definition: The term "air pollutant" means any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air. Such term includes any precursors to the formation of any air pollutant, to the extent the Administrator has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used. 7602(g).

are similar to those contained in the Clean Air Act (CAA).[13] The Supreme Court has held the CAA definition includes greenhouse gases, including methane.[14] Indeed, DEP already regulates methane from new and modified sources pursuant to its General Permit requirements and there is nothing in the APCA that restricts DEP from regulating methane from existing sources.[15]

Oil and Gas Emissions from Existing Sources Are Significant Sources of Methane

Methane, the primary component of natural gas, is a powerful climate pollutant that is 36 times more potent than carbon dioxide on a 100-year timeframe and 87 times more potent on a 20-year timeframe.[16] Leaky, outdated, and malfunctioning equipment at oil and gas sites constitute a primary source of methane emissions, and the proposed requirements in this rulemaking will significantly help reduce harmful emissions from Pennsylvania's thousands of existing facilities.

Recent EDF analysis found that existing oil and gas sources are responsible for the release of 1.1 million tons of methane annually.[17] This estimate is based on 2017 production data and emission modeling from a 2018 Science study, which draws on six years of peer-reviewed research conducted by EDF and over 140 research and industry experts from 40 institutions and 50 companies. These emissions contribute to harmful climate change that has already started impacting the Commonwealth. In Pennsylvania, temperatures increased by more than 1.8°F since the early 20th century and are expected to increase by an additional 5.4°F by 2050. Annual precipitation has increased by approximately 10 percent since the early 20th century and is expected to increase by another 8 percent by 2050. [18] Climate impacts such as more frequent extreme weather events and increased health risks from air pollution, diminished water quality and heat stress will continue to impact Pennsylvania putting citizens and local industries at risk.[19]

In addition to contributing harmful pollution to the atmosphere, methane emissions also represent waste of a valuable resource. EDF estimates that the 1.1 million tons of methane emitted to the

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[13] The term "air pollutant" means any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air. Such term includes any precursors to the formation of any air pollutant, to the extent the Administrator has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used. 42 U.S. Code § 7602(g).

[14] Massachusetts v. EPA, 549 U.S. 497, 528 (2007).

[15] General Plan Approval and General Operating Permit for Natural Gas Compression Stations, Processing Plants and Transmission Stations (GP-5), the General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A), (BAQ-GPA/GP-5A, 2700-PM-BAQ0268).

[16] Environmental Defense Fund, "Methane: The other important greenhouse gas," *available at* https://www.edf.org/climate/methane-other-important-greenhouse-gas.

[17] EDF Finds Pennsylvania Oil and Gas Methane Emissions are Double Previous Estimate (May 13, 2020), https://www.edf.org/media/edf-analysis-finds-pennsylvania-oil-and-gas-methane-emissions-are-double-previous-estimate.

[18] Pennsylvania Department of Environmental Protection, Climate Action Plan, p. 25 (Apr. 29, 2019), http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=1454161&DocName=2018%20PA%20CLIMATE%20ACTION%20PLAN.PDF%20%20%20%3cspan%20style%3D%22color:blue%3b%22%3e%28NEW%29%3c/span%3e

[19] *Id*. at 25-26.

atmosphere equates to 57 billion cubic feet of natural gas that could otherwise be sold.[20] Reducing emissions from existing sources can result in significantly more gas being brought to market, to the benefit of Pennsylvania operators and citizens. Implementing common sense, economically sensible regulations is smart policy for the Keystone state.

Pennsylvania Must Act to Reduce VOCs from Existing Sources

VOC emission control measures are necessary to attain and maintain the health-based and welfare-based 8-hour ozone National Ambient Air Quality Standards ("NAAQS") in the Commonwealth and to satisfy related CAA requirements.[21] Oil and gas operations in Pennsylvania emitted over 63,000 tons of smog-forming volatile organic compounds in 2017, according to EDF's Pennsylvania Oil and Gas Emissions Data.[22] VOCs are precursors to the formation of ground-level ozone, a public health hazard. Smog and ozone pollution can trigger a variety of health problems including chest pain, coughing, throat irritation, and airway inflammation. It also can reduce lung function and harm lung tissue. Ozone can worsen bronchitis, emphysema, and asthma, leading to increased medical care.[23] Ozone also has negative environmental and agricultural effects, harming sensitive vegetation and ecosystems, including forests, parks, wildlife refuges and wilderness areas. In particular, ozone harms sensitive vegetation during the growing season.[24]

Section 182(b)(2) of the CAA provides that for moderate ozone nonattainment areas, states must revise their SIPs to include RACT for sources of VOC emissions covered by control techniques guidelines documents issued by the EPA prior to the area's date of attainment of the applicable ozone NAAQS. Moreover, section 184(b)(1)(B) of the CAA requires states in the Ozone Transport Region ("OTR"), including the Commonwealth, to submit a SIP revision requiring implementation of RACT for all sources of VOC emissions in the state covered by a specific CTG and not just for those sources located in designated nonattainment areas of the state.

The Commonwealth also must reduce VOCs in order to achieve and maintain the NAAQS.[25] As DEP recognizes in the preamble to the proposal, Pennsylvania is home to numerous areas that have maintenance plans in place for the 1997 and 2008 ozone standards and a marginal ozone Nonattainment Area.[26] Adoption of the VOC emission control measures in this proposed rulemaking, if strengthened, would ensure the Commonwealth continues its progress in attaining and maintaining the 2008 8-hour ozone NAAQS.[27] Moreover, on October 26, 2015, the EPA again lowered the primary and secondary ozone NAAQS, this time to 0.070 ppm (70 ppb) averaged over 8 hours.[28] On June 4, 2018, the EPA designated Bucks, Chester, Delaware, Montgomery and Philadelphia counties as marginal nonattainment, with the rest of the Commonwealth designated

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[20] EDF Finds Pennsylvania Oil and Gas Methane Emissions are Double Previous Estimate (May 13, 2020), https://www.edf.org/media/edf-analysis-finds-pennsylvania-oil-and-gas-methane-emissions-are-double-previous-estimate.
[21] Preamble, 3-8.
[22] EDF, Pennsylvania Oil and Gas Emissions Data, https://www.edf.org/pa-oil-gas/#/air-emissions
[23] EPA website, Ground-Level Ozone Basics, https://www.epa.gov/ground-level-ozone-pollution/ground-level-ozone-basics#:~:text=Breathing%20ozone%20can%20trigger%20a,Learn%20more%20about%20health%20effects.
[24] *Id*.
[25] Clean Air Act, §172(c)(1).
[26] Preamble, 3.
[27] Preamble, 3-4.
[28] *See* 80 FR 65291 (October 26, 2015).

attainment/unclassifiable.[29] The Department must ensure that the 2015 8-hour ozone NAAQS are attained and maintained by implementing permanent and federally enforceable control measures.

Technologies are Available to Cost Effectively Reduce CH4 and VOCs from Existing Sources

Fortunately, cost effective solutions are readily available to reduce the routine venting, flaring and leaking of natural gas and to ensure more natural gas is used or sold. In March 2020, the IEA found that one third of the world's methane emissions can be cut at no net cost to operators, accounting for current depressed oil prices.[30] This analysis tracks with prior analysis conducted by ICF International that found off-the-shelf technologies and practices such as quarterly leak inspections can slash emissions by roughly 40% for a penny per thousand cubic foot of natural gas produced. As described in more detail below, many of these solutions are already required for existing oil and gas wells in Colorado, Utah, Wyoming, and California, as well as other major oil and gas producing jurisdictions, such as British Columbia, Alberta and Mexico.

Technical Comments

We suggest specific improvements to the rule below based on requirements adopted in other jurisdictions that, if adopted, will ensure Pennsylvania fulfills its commitment to reduce methane while also meeting its CAA obligations to establish RACT for existing sources of VOCs. Our comments focus primarily on improvements to the leak detection and repair requirements for well sites, as we believe this is the area of the rule that requires the greatest improvement. Specifically, we propose:

(1) Requiring that all well sites conduct quarterly, comprehensive inspections for leaks and monthly audio-visual-olfactory inspections or, alternatively, significantly narrowing the number of wells and the potential emissions that are exempted from the rule;
(2) Removing the step-down provisions contained in the LDAR requirement for well sites;
(3) Specifying in the rule that an alternative leak detection device or method must achieve equivalent emission reductions as allowed devices or methods.

For other sources, we propose:

(1) Increasing the destruction removal efficiency of all flares used to control emissions from tanks, pumps at well sites, and centrifugal compressors to 98%.
(2) Utilizing the more protective 2.7 tpy VOC control threshold for all existing tanks rather than 4 tpy VOC threshold.
(3) Adopting a self-certification requirement that tracks reporting requirements to provide a basis for enforcement actions due to false or inaccurate compliance reporting.

Finally, we recommend changing the title of the rule to "Control of Hydrocarbon Emissions from Oil and Natural Gas Sources" rather than "Control of VOC Emissions from Oil and Natural Gas Sources" to reflect the fact that this rule reduces both CH_4 and VOC emissions.

[29] *See* 83 FR 25776.
[30] IEA, Global Methane Emissions from Oil and Gas (Mar. 31, 2019), https://www.iea.org/articles/global-methane-emissions-from-oil-and-gas.

A. Leak Detection and Repair

We recommend DEP require quarterly, instrument-based, comprehensive leak detection and repair (LDAR) for all existing wells. In addition, operators should be required to check wells monthly for leaks using audio-visual-olfactory methods (AVO). Emissions from leaks and abnormal operating conditions are the largest source of methane emissions, per EDF's inventory. These sources contributed a total of 1,107, 800 tons of CH4 in Pennsylvania in 2018.[31] Numerous studies have demonstrated that leaks are a very large source of harmful methane emissions at upstream oil and gas facilities. The scientific consensus, based on numerous studies involving direct measurement of oil and gas leaks, demonstrates the heterogeneous, unpredictable, and ever-shifting nature of equipment leaks. These characteristics strongly point toward the need for frequent inspections to identify and repair leaking components and equipment. Specifically:

- ***Leaks are heterogeneously distributed***
  There is considerable evidence that emissions from equipment leaks are heterogeneously distributed—with a small percentage of sources accounting for a large portion of emissions[32]—and that existing inventories do not accurately reflect the presence of these "super-emitters."[33] Numerous studies undertaken in different basins in the U.S have underscored the need for frequent, if not continuous, LDAR.[34] Other studies have found that measured emissions exceeded estimates contained in emissions inventories, in one instance by as much as 50%.[35] One explanation for the delta between reported and measured emissions is abnormal operating conditions that are not reflected in average emission factors or standard reporting protocols used by operators.[36]

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[31] EDF analysis based on EDF inventory of methane emissions from oil and gas sources.
[32] Zavala-Araiza, D., et al., (2017) "Methane emissions from oil and gas production sites in Alberta, Canada", draft attached as Ex. 4; Allen, D.T., *et al.*, (2013) "Measurements of methane emissions at natural gas production sites in the United States," *Proc. Natl. Acad.*, **110**, ("Allen (2013)"), *available at* http://www.pnas.org/content/110/44/17768.full; ERG and Sage Environmental Consulting, LP, "City of Fort Worth Natural Gas Air Quality Study, Final Report" ("Fort Worth Study") (July 13, 2011), *available at* http://fortworthtexas.gov/gaswells/default.aspx?id=87074 (finding that the highest 20 percent of emitting sites account for 60–80 percent of total emissions from all sites; the lowest 50 percent of sites account for only 3–10 percent of total emissions); Zavala-Araiza, *et al.*, (2015) "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," *Environ. Sci. Technol*., 49, at 8167–8174 ("Zavala-Araiza (2015)"), *available at* http://pubs.acs.org/doi/pdfplus/10.1021/acs.est.5b00133 (finding that "functional super-emitter" sites represented approximately 15% of sites within each of several different "cohorts" based on production, but accounted for approximately 58 to 80% of emissions within each production cohort); Zavala-Araiza et al., (2015) "Reconciling divergent estimates of oil and gas methane emissions," Proceedings of the National Academy of Sciences, vol. 112, no. 51, 15597 at 15600 (finding that "at any one time, 2% of facilities in the Barnett region are responsible for 80% of emissions, and 10% are responsible for 90% of emissions.") ("Barnett Synthesis").
[33] Barnett Synthesis at 15599.
[34] *Id*. See 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.*, **49**, ("Harriss (2015)"), *available at* https://pubs.acs.org/doi/full/10.1021/acs.est.5b02305 (providing a summary of the 12 studies that were part of the coordinated campaign).
[35] *See* Harriss.
[36] Zavala-Araiza, D., et al., (2017) at 12; see also Harriss.

- ***Equipment leaks are unpredictable.***
  Recent studies have assessed whether well characteristics and configurations can predict super-emitters, concluding that they are only weakly related,[37] and that these emissions are largely stochastic. In particular, the Barnett coordinated campaign cited above found that abnormal operating conditions, such as improperly functioning equipment could occur at different points in time across facilities.[38] As a result, Zavala-Araiza, et al. reported that inspections need "to be conducted on an ongoing basis" and "across the entire population of production sites."[39] In addition, a recent helicopter study of 8,220 well pads in seven basins, including 2,067 well pads in the southwest Pennsylvania region of the Marcellus Basin, confirms that leaks occur randomly and are not well correlated with characteristics of well pads, such as age, production type or well count.[40] That study focused only on very high emitting sources, given the helicopter survey detection limit which ranged from 35–105 metric tpy of methane. The paper reported that emissions exceeding the high detection limits were found at 327 sites. 92 percent of the emission sources identified were associated with tanks, including some tanks with control devices that were not functioning properly and so could be expected to be addressed through a leak detection and repair program. While the study did not characterize the individually smaller but collectively significant leaks that fell below the detection limit, it nonetheless confirms that high-emitting leaks occur at a significant number of production sites and that total emissions from such leaks are very likely underestimated in official inventories.

- **Super-emitters shift in time and space.**
  Abnormal operating conditions, such as improperly functioning equipment, can occur at different points in time across facilities.[41] While it is true that at any one time roughly 90% of emissions come from 10% of sites, these sites shift over time and space—meaning that, at a future time, a different 10% of sources could be responsible for the majority of emissions.[42] Other studies confirm these findings[43] and underscore the importance of frequent,

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[37] Lyon, *et al.*, (2015), "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region," *Environ. Sci. Technol.*, **49**, at 8147-57, *available at* http://pubs.acs.org/doi/pdf/10.1021/es506359c; *See also* Brantley, H.L., *et. al.*, "Assessment of methane emissions from oil and gas production pads using mobile measurements," Environmental Science & Technology, 48(24), pp.14508-14515, *available at* http://pubs.acs.org/doi/abs/10.1021/es503070q (assessing where well characteristics can predict emissions, concluding that they are weakly related and that emissions are largely stochastic); Zavala-Araiza (2015) ("large number of facilities in the Barnett region cause high emitters to always be present, and these high-emitters seem to be spatially and temporally dynamic. . . .To reduce those emissions requires operators to quickly find and fix problems that are always present at the basin scale but that appear to occur at only a subset of sites at any one time, and move from place to place over time.").
[38] Harriss (2015)
[39] Zavala-Araiza (2015), at 8167−8174.
[40] Lyon, et al., "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environ. Sci. Technol.*, 2016, *50* (9), pp 4877–4886, available at http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705.
[41] Barnett Synthesis, *supra* note 5 at 15600.
[42] *Id*.
[43] Allen, D.T. et al., "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings," *Environ. Sci. Technol*., (2015), 49 (1), pp 641–648, available at http://pubs.acs.org/doi/abs/10.1021/es504016r; Mitchell, A.L., et al, (2015) "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants," *Environ. Sci. Technol*, 2015, 49 (5), pp 3219–3227, available at http://pubs.acs.org/doi/abs/10.1021/es5052809; R. Subramanian, et al, (2015) "Methane Emissions from

if not continuous, inspections to identify and repair stochastic, heterogeneous leaks. A study of facilities in the Barnett shale found that 30% of the sites emitted more than 1% of production.[44]

A comprehensive, instrument-based robust leak detection and repair program that requires operators to inspect for leaks on a quarterly basis and requires monthly AVO inspections can significantly reduce emissions from abnormal operating conditions and leaks.

DEP Should Require Quarterly Inspections to Reduce Leaks

Other jurisdictions have successfully established regulations that require quarterly LDAR for existing sources including Colorado,[45] Wyoming,[46] California,[47] and Mexico.[48] A quarterly inspection schedule would put Pennsylvania operators on par with states such as California[49] as well as Wyoming[50] and Colorado.[51]

California requires operators in the production and processing segments, as well as those operating compressor stations in the gathering and boosting and storage and transmission segments, to conduct quarterly inspections to detect methane emissions.[52]

Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol*, available at http://pubs.acs.org/doi/abs/10.1021/es5060258.

[44] Harriss, *et al*.

[45] Colorado Air Quality Control Commission, Regulation Number 7, 5 C.C.R. 1001-9, § C.II.E.4.d (quarterly inspections required for mid-sized facilities; more frequent inspections required for larger sources and less frequent inspections for smaller facilities).

[46] In Wyoming non-attainment areas, new and existing facilities must be inspected quarterly for leaks of 4 tpy or more of VOCs. Operators in Wyoming must record dates and results of LDAR inspections, including the date and type of corrective action taken as a result of the inspections. Components to be inspected include flanges, connectors, open-ended lines, pumps, valves, and "other" components listed in EPA Table 2-4. Operators must inspect using OGI, Method 21 or another approved technology. WDEQ, Oil and Gas Production Facilities Ch. 6, Section 2 Permitting Guidance for the UGRB (2016), Available at: http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf

[47] In California, owners or operators must conduct quarterly inspections using Method 21. Since January 1, 2020, there is a 1,000 ppm leak threshold for repairs. Leaks must be repaired within 2, 5 or 14 days, depending on the size of the leak. Components or component parts which incur 5 repair actions within a continuous 12-month period must be replaced and re-measured to determine that the component is below the minimum leak threshold. 17 C.C.R. § 95669 (March 24, 2006), available at https://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20Appx%20A%20Regulation%20Text.pdf

[48] Mexico requires quarterly LDAR and inspection frequency is tied to emission thresholds. Mexico, Agencia de Seguridad, Energia y Ambiente (ASEA) regulations, available at http://www.dof.gob.mx/nota_detalle.php?codigo=5543033&fecha=06/11/2018.

[49] CARB 17 C.C.R. § 95669(g), available at https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasappa.pdf.

[50] Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, §(6)(g)(1)(a); Wyo. Dep't of Envtl. Quality, Oil and Gas Production Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised May 2016) ("WY Permitting Guidance"), 22, *available at* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf

[51] Colorado 5 C.C.R. 1001-9, Reg. 7, § XVII.F.4.a (Feb. 24, 2014); current provision at § C.II.E.4.d.

[52] CARB § 95668(g).

Colorado requires that operators inspect for and repair hydrocarbon leaks, consisting of methane as well as other organic compounds, at three types of new and existing facilities: compressor stations, well sites, and storage tank batteries. The rules require quarterly inspections at mid-sized facilities.[53] The size of the facility is determined based on the potential to emit volatile organic compounds (VOCs), although operators are required to repair hydrocarbon leaks including leaks from components that primarily emit methane.[54] Operators may use optical gas imaging, Method 21, or another approved instrument.

Wyoming requires quarterly instrument-based inspections at all new and existing well sites in its Upper Green River Basin with the potential to emit 4 tons of VOCs from fugitive components.[55] Like Colorado, operators in Wyoming may use either Method 21 or an optical gas imaging instrument, or other approved instrument.

Comprehensive quarterly instrument-based leak inspections can reduce emissions from improperly operating equipment, such as gas-powered pneumatic controllers, dump valves on separators, access points on storage tanks, as well as traditional components.

Quarterly Inspections are Cost Effective

Information from other states, leading operators and independent consulting groups demonstrates that quarterly inspections are highly cost effective.

California. The California Air Resources Board ("CARB") found the cost of conducting quarterly inspections at production facilities to be highly cost effective. CARB estimates the costs are $23 per metric ton of CO_2e reduced (accounting for savings from recovered product) to $26 per metric ton of CO_2e reduced (not accounting for savings).[56] These estimates assume a 20-year global warming potential for methane.

Colorado. The final cost benefit analysis prepared by the Colorado Air Pollution Control Division in support of its LDAR program demonstrates that quarterly inspections are cost effective. For mid-sized well sites, Colorado found the cost effectiveness of quarterly LDAR inspections to be $1,019 per ton of VOC reduced and $679 per ton of CH4/ethane reduced for facilities located in the Denver non-attainment area. For remote facilities located outside the Denver-Julesberg basin, Colorado determined quarterly inspections to be cost effective at $1,268 per ton of VOC reduced and $648 per ton of CH4/ethane reduced.[57]

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[53] Colorado 5 C.C.R. 1001-9, Reg. 7, § C.II.E.4.d.
[54] *Id*. at XVII.a.5.
[55] WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6.
[56] CARB. Revised Emission and Cost Estimates for the Leak Detection and Repair Provision. (February, 2017). Available at: https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf.
[57] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) ("CAPCD Cost-Benefit"), at 28, Table 34, *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573.

ICF International. In 2015, EDF commissioned ICF to develop a stochastic model to estimate the cost-effectiveness of LDAR at different types of facilities.[58] The analysis seeks to develop facility models that replicate real world situations and capture variations in these characteristics by using a Monte Carlo simulation to analyze facility emissions, reductions and costs. The attached power point describes the model inputs and assumptions underpinning each of the analyzed scenarios and sets forth results. EDF converted ICF's cost effectiveness estimates into dollars per short tons of methane and determined that quarterly inspections are equal to $262 per short ton of methane reduced, assuming $3 gas; $234 per short ton of methane reduced, assuming $4 gas, and $187 per short ton of methane reduced, assuming $3 gas and the use of a contractor to perform the inspection.

Carbon Limits. This study is based on actual leak data from over 4,000 leak detection and repair inspections of oil and gas facilities, such as well sites, gas compressor stations, and gas processing plants. The inspectors used infrared cameras to identify over 58,000 individual components that were leaking or venting gas. The inspection firms provided facility inspection costs and, for every leak they found, data such as the size of the leak and how much it would cost to repair. LDAR surveys performed quarterly would abate methane at a net cost of less than $280 per metric ton ($11/ton CO_2e using a global warming potential of 25) for all types of facilities. Per this study, over 90% of the gas leaking from these facilities is from leaks that can be fixed with a payback period of less than one year (assuming gas prices of $3 per thousand cubic feet).[59]

Center for Methane Emissions Solutions, **Colorado Case Study**. CMES interviewed 10 companies in Colorado operating after Colorado adopted its leak detection and repair program in 2014. It found that 7 out of 10 companies interviewed reported that additional revenues from fixing leaks more than covers the costs of finding and fixing leaks.[60]

Jonah Energy. Jonah Energy operates in the Upper Green River Basin in Wyoming. Jonah Energy's Enhanced Direct Inspection & Maintenance ("EDI&M") Program in Wyoming has been ongoing for the last five-and-a-half years and includes a *monthly* LDAR program using instrument-based surveys (i.e., IR camera technology). According to Jonah, "[b]ased on a market value of natural gas of $4/MMBtu, the estimated gas savings from the repair of leaks identified exceeded the labor and material cost of repairing the identified leaks" while also significantly reducing pollution.[61] Jonah has reported that this highly cost-effective LDAR program has reduced fugitive VOC emissions from its facilities by over 75%, indicating that methane and other hydrocarbon losses have also been reduced by a similar proportion.[62] Jonah's experience that gas savings from

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[58] ICF International. "Leak Detection and Repair Cost- Effectiveness Analysis." Prepared for Environmental Defense Fund. (December 2015). Slide 25. Ex. B.
[59] Carbon Limits, Fact Sheet, Fixing the Leaks: What would it cost to clean up natural gas leaks?, available at http://www.catf.us/resources/factsheets/files/LDAR_Fact_Sheet.pdf. Full report available at http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.
[60] Center for Methane Emissions Solutions, Colorado Case Study, available at https://static1.squarespace.com/static/558c5da5e4b0df58d72989de/t/57110da386db43c4be349dd8/1460735396217/Methane+Study.pdf.
[61] Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Existing Source Regulations (Dec. 10, 2014). Ex. C.
[62] Jonah Energy, Presentation at WCCA Spring Meeting at 16 (May 8, 2015), on file with EDF.

repairs often exceed the cost of performing repairs to identified leaks is also borne out by the Carbon Limits report[63] and analysis carried out by Colorado.[64] There is mounting industry-supplied evidence that frequent LDAR is cost-effective.[65]

DEP Should Require Operators to Inspect Pneumatic Controllers during LDAR Inspections.

DEP should ensure that operators inspect pneumatic controllers to confirm they are not emitting excessively during routine LDAR inspections. Several recent studies report that pneumatic controllers often vent more than they are designed to vent.

Allen et al. (2015). As part of this study, an expert group reviewed the behavior of the 40 controllers with the highest vent rates in the study, which were responsible for 81 percent of the gas loss from all controllers in the study (377 controllers). The expert group concluded that "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."[66] Of the forty highest venting controllers, 28 were judged to be operating incorrectly due to equipment issues. The study reported that many devices observed to actuate (often referred to as "intermittent-bleed controllers" in the US) also vented continuously.

Allen et al. (2013). As noted above, this study reported that venting rates from low-bleed pneumatic controllers were 270% higher than EPA's emissions factor for these devices – 5.1 scfh.[67] Many low-bleed controllers are specified to vent far less than this: EPA's Gas Star program has documented many low-bleed controller models with bleed rates of less than 3 scfh,[68] and of course the emissions factor used by EPA for low-bleeds (1.39 scfh), 40 C.F.R. § 98.233(a), implies that many low-bleeds are expected to vent at a very low level. Assuming that some low-bleed controllers are performing as specified, the high emissions rate observed by Allen *et al*. (2013) implies that many "low-bleed pneumatic controllers" are in fact venting more than the design threshold of 6 scfh for low-bleeds, 40 C.F.R. § 60.5390(c)(1) – or much more than 6 scfh – simply to raise the average venting rate to 5.1 scfh.

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[63] Carbon Limits, *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras*, 16 (Mar. 2014) ("Carbon Limits 2014"), *available at* http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

[64] Colorado Air Pollution Control Division used an entirely different method than Carbon Limits to predict that almost 80 percent of repair costs for well facilities will be covered by the value of conserved gas. *See* CAPCD Cost-Benefit, at Table 30.

[65] Several companies that engaged in the development of Colorado's regulations provided evidence that frequent LDAR is cost-effective. In particular, Noble estimated the cost-effectiveness of Colorado's tiered program at "between approximately $50/ton and $380/ton VOC removed" at well production facilities. (Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the Matter of Proposed Revisions to Regulation Number 3, Parts A, B, and C, Regulation Number 6, part A, and Regulation Number 7 Before the Colorado Air Quality Control Commission, at 7). On file with EDF.

[66] Allen, *et al*. (2015).

[67] Allen *et al*. (2013).

[68] EPA, *Lessons Learned from Natural Gas Star Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, Appendix 1 (2006), *available at* http://www3.epa.gov/gasstar/documents/ll_pneumatics.pdf.

City of Fort Worth Study. The Fort Worth Study measured venting rates from 489 intermittent pneumatic controllers, using infrared cameras, Method 21, and a HiFlow sampler for quantification, and found that many of these controllers were venting constantly and at very high rates, even though these devices were used to operate separator dump valves and were not designed to vent in between actuations.[69] Average venting rates for the controllers in the Fort Worth Study were at a rate that approaches the average venting rate of a high-bleed pneumatic controller. According to the study authors, these emissions were frequently due to improperly functioning or failed controllers.[70]

British Columbia Study. The Prasino study of pneumatic controller emissions in British Columbia also noted the potential for maintenance issues to lead to abnormally high bleed rates.[71] Although the researchers did not identify a cause for these unexpectedly high venting rates, the results are consistent with the observation that maintenance and operational issues can lead to high emissions.

The Carbon Limits Study. The Carbon Limits Report confirms that pneumatic controllers often function improperly and vent at excessive rates.[72]
In response to this widespread problem, California's Air Resources Board, in their 2017 standards regulating greenhouse gas emissions from oil and gas operations,[73] put in place a straightforward, clear, enforceable, and effective approach to pneumatic controller inspections. These standards require that operators regularly inspect both actuating (intermittent-bleed) and continuous-bleed pneumatic controllers to ensure that they are operating properly.

CARB's standards require quarterly LDAR inspections of oil and gas well pads and compressor stations,[74] and require checking all intermittent-bleed pneumatic controllers for improper continuous emissions during each inspection.[75] Controllers improperly emitting between actuation must be repaired.[76]

In addition, operators of any existing continuous-bleed controller (all of which must be low-bleed since high-bleed controllers in California had to be replaced by January 1, 2019[77]) must "directly measure" emissions from those controllers on an annual basis, and repair or replace any controller

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[69] ERG and Sage Environmental Consulting, LP, *City of Fort Worth Natural Gas Air Quality Study, Final Report.* (July 13, 2011) ("Fort Worth Study"), *available at* http://fortworthtexas.gov/gaswells/default.aspx?id=87074.
[70] *See id.* at 3-99 to 3-100 ("Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually").
[71] *See*, The Prasino Group, *Determining bleed rates for pneumatic devices in British Columbia; Final Report*, 19 (Dec. 18, 2013). Available at: http://www.bcogris.ca/sites/default/files/ei-2014-01-final-report20140131.pdf.
"Certain controllers can have abnormally high bleed rates due to operations and maintenance; however, these bleed rates are representative of real world conditions and therefore were included in the analysis.".
[72] Carbon Limits. "Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Program Using Infrared Cameras." (March 2015). Available at: http://catf.us/resources/publications/view/198.
[73] Cal. Air Res. Bd., *CARB Approves Rule for Monitoring and Repairing Methane Leaks from Oil and Gas Facilities* (Mar. 23, 2017), www.arb.ca.gov/newsrel/newsrelease.php?id=907.
[74] CARB 17 C.C.R. § 95669(a),(g).
[75] *Id.* § 95668(e)(3).
[76] *Id.*
[77] *Id.* § 95668(e)(2)(A)(1).

emitting more than six scf per hour.[78]

This approach does not impose significant cost on operators when LDAR programs are in place. The incremental cost of checking intermittent-bleed controllers for continuous emissions during an LDAR inspection is very low, since the inspector is already on site. In most cases the device will not be actuating and the incremental cost of inspecting one more component is very small.

Direct measurement of emissions from continuous-bleed controllers during LDAR inspections has a small incremental cost, as it is more time consuming than checking intermittent-bleed controllers between actuations and may require the use of instruments that inspectors are not routinely using. Nevertheless, such measurements are commonly performed during LDAR inspections. GreenPath Energy, a firm providing LDAR inspection services to oil and gas producers in the US and Canada, estimates that the incremental cost of directly measuring emissions from a pneumatic controller is $36.43 per controller.[79] This estimate accounts for both the extra time required on site and the instrument used to measure emissions from the controller. This cost is a very conservative estimate for continuous-bleed controllers, since GreenPath estimated the cost based on measuring emissions from an actuating controller, which requires measurement for about 15 minutes. As GreenPath notes, emissions from pressure controllers, transducers, and temperature controllers (i.e., non-actuating controllers) can be measured in as little as 5 minutes.[80]

Colorado also requires operators to inspect gas-powered pneumatic controllers during LDAR inspections. Colorado initially promulgated this requirement in 2017 only for well sites operating in the Denver Metropolitan 8hr Ozone Nonattainment area. The state recently extended this requirement to apply to all gas-powered pneumatics across the state.[81] Under the new rule, operators must inspect all natural gas-driven pneumatic controllers at well production facilities, natural gas compressor stations, and natural gas processing plants (storage tanks only) statewide during routine LDAR inspections in order to detect malfunctioning pneumatic controllers.

Operators Must Conduct AVO Inspections Monthly at all Wells.

Any instrument-based inspections program should be coupled with monthly AVO inspections. Prudent operators inspect their assets routinely in order to ensure that production is occurring normally. Requiring an operator to look for leaks during routine monthly trips to their well sites does not impose any costs on operators, yet has the potential to identify abnormally operating equipment that can cause excess emissions to the atmosphere. Other states, such as Colorado and California, require monthly AVO in addition to quarterly instrument-based inspections.[82] DEP must add a provision to the rule requiring operators conduct monthly AVO inspections at all well sites, regardless of production or emission levels.

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[78] *Id.* § 95668(e)(2)(A)(3), (4).
[79] GreenPath Energy (2017), "Incremental costs for direct measurement of pneumatic device emission rates during Leak Detection and Repair Inspections." (June 2017). On file with EDF.
[80] *Id*, p. 2.
[81] CO Reg. 7, § III.F.2.
[82] CARB § 95668(g); Colorado 5 C.C.R. 1001-9, Reg. 7, § C.II.E.4.d.

DEP Should Remove the Step Down Provision

DEP must also remove the step down provison that allows operators to reduce the inspection frequency if less than 2% of components are found to be leaking after two consecutive inspections. DEP'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.[83] EPA observed: "[e]xperience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions."[84] 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.[85]

Furthermore, DEP's proposed metric for determining adjusted frequency—the percentage of leaking components— is not an accurate predictor of a facility's emissions performance. At a conceptual level, if emissions from leaking components were homogenously distributed, the percentage of components leaking at a facility would be a good indicator of facility-level emissions. However, there is overwhelming evidence that leak emissions follow a skewed, highly-heterogeneous distribution, with a relatively few number of sources accounting for a large portion of emissions. In such circumstances, the percentage of leaking components will not accurately reflect emissions and should not be used to determine the frequency of LDAR survey requirements.

EDF empirically examined the effects of percent thresholds using data from the City of Fort Worth Study Air Quality Study,[86] which includes both component level emissions information and site-level data. Figure 1 below shows the results of this analysis. Figure 1 compares site-level emissions to the percentage of leaking components and demonstrates that the individual sites with the highest emissions fall below DEP's proposed 2 percent threshold. Figure 2 aggregates site-level emissions at each of these thresholds. Sites with less than 2 percent leaking components constituted 90% of total emissions and 80% of all sites.

[83] EPA, "Leak Detection and Repair: A Best Practice Guide," October 2007, at 1, available at http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf
[84] *Id*. at 23.
[85] *Id.*
[86] ERG and Sage Environmental Consulting, LP, "City of Fort Worth Natural Gas Air Quality Study, Final Report" ("Fort Worth Study") (July 13, 2011), available at http://fortworthtexas.gov/gaswells/default.aspx?id=87074

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

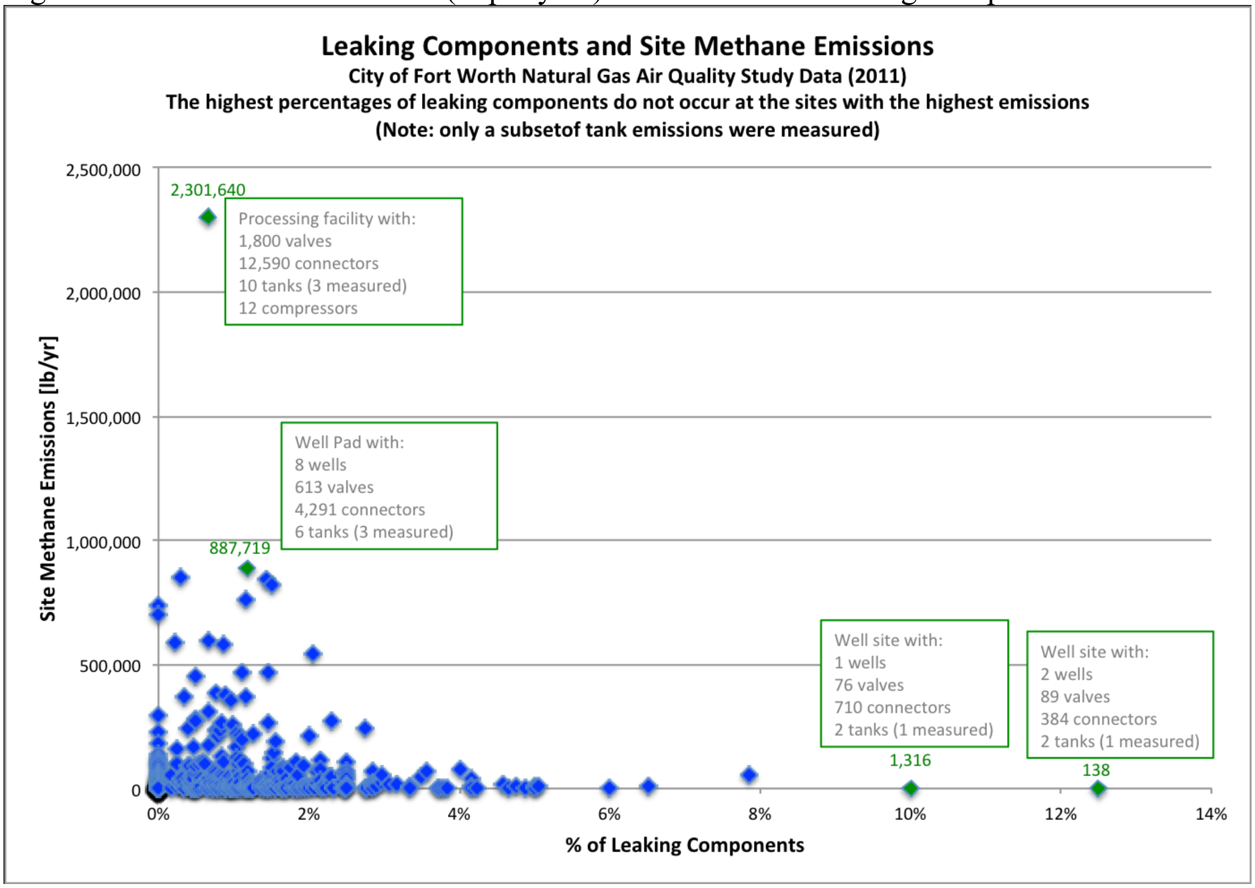
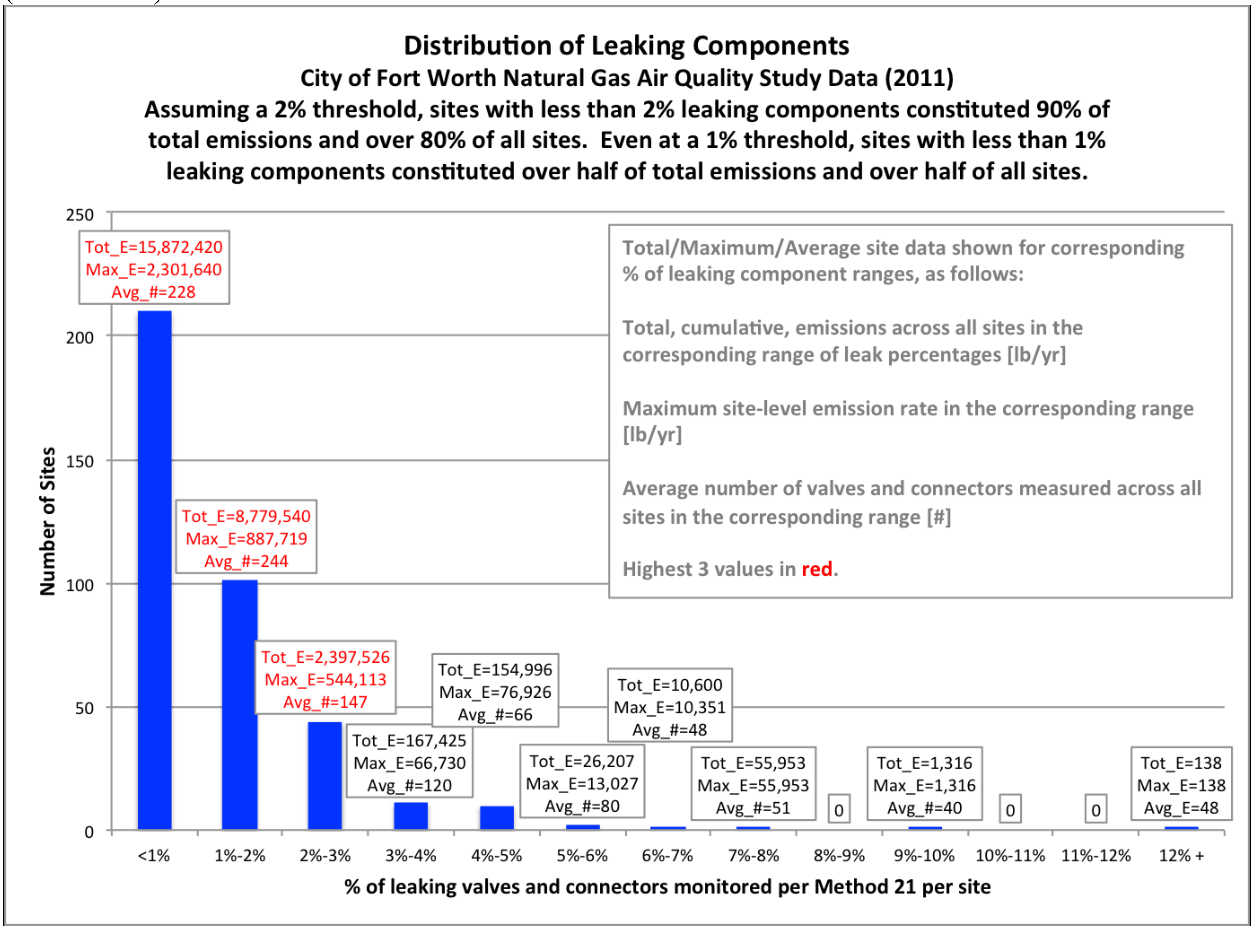


Figure 2: Number of Sites versus Percent of Leaking Valves and Connectors Monitored per Site (Method 21)



Data from operators collected as part of Colorado's LDAR program further support a fixed inspection requirement. Colorado's approach requires operators to inspect for leaks at all but the smallest sites on a fixed annual, quarterly, or monthly basis (depending on the facility's tanks emission potential). 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014). Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to Encana, "[our] experience shows leaks continued to be detected well into the established LDAR program."[87] Encana's data shows that while the largest reductions in VOC emissions occur in the first year of an LDAR program, significant emission reductions are still being realized in subsequent years of the LDAR program – because leaks re-occur at facilities.[88]

We strongly recommend that DEP remove provisions allowing operators to reduce frequency based on the percentage of leaking components identified in prior surveys. As discussed above, studies suggest that past emissions are not a good predictor of future emissions given the prominent role that improperly functioning equipment, poorly maintained equipment, and other random

[87] Rebuttal Statement of Encana Oil and Gas (USA) Inc., Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3, 7, and 9, at 10. Exhibit D
[88] *Id*. at 10-11.

events play in overall emissions. Facilities with low emissions during one survey may nonetheless experience such an event in the future, and less frequent monitoring at these sites would delay repairs to end these important and harmful emissions. Accordingly, we recommend DEP finalize an LDAR standard based on fixed frequencies.

DEP Should Remove the Low-Producing Well Exemption

Pennsylvania DEP has exempted low-producing wells from the LDAR requirement. Low-producing wells are defined per the EPA CTG as those that produce less than 15 barrels of oil equivalent per day ("BOE/d") and have a gas-to-oil ratio ("GOR") less than 300 standard cubic feet ("scf") of gas per barrel of oil produced. This exemption has the effect of carving out the vast majority of wells in the state. Per EDF's analysis, approximately 71,000 wells out of the 77,540 wells producing oil or gas in 2017 would be exempt from any inspection requirements, even minimal AVO inspections.[89]

Low-producing wells release upwards of 484,000 tons of methane each year – representing about 50% of total emissions. This includes approximately 285,524 tons from fugitive and abnormal operating conditions.[90] Given the foregoing, the low producing wells exemption frustrates the purpose and efficacy of the proposed rule and should be jettisoned.

Narrower Alternatives to Low Producing Well Exemptions

As stated above, because quarterly inspections for ALL wells in Pennsylvania is cost effective, we oppose an exemption for low producing wells. However, if DEP determines that some consideration should be given to smaller operators and facilities, we propose two narrower exemptions.

The first alternative quantifies the financial and environmental impacts of controlling emissions from a subset of marginal wells. For this analysis EDF used DEP's threshold of 15 barrels of oil equivalent per day (BOE/d) or a gas to oil ratio of less than 300 scf/bbl to identify marginal wells.

The second alternative analyzes the impact of establishing a tiered LDAR approach based on production levels. This is similar to the approach in Colorado, but inspection frequency is tiered off of production thresholds rather than actual uncontrolled VOC emissions.

- *Alternative 1: Require Quarterly Inspections at all Well Sites Operated by An Operator that has at Least 1 Non-exempt Well in its Portfolio.*

Our first recommendation is to limit any marginal well exemption to those operators that only have low producing wells in their portfolio. For this analysis EDF identified all wells in the state that quality for DEP's marginal well exemption as well as all wells in the state that would be subject to LDAR per the proposal. EDF then examined operatorship records of all wells in the state to

[89] EDF, Pennsylvania Low-producing Well Technical Analysis (Exhibit A).
[90] Id.

understand how many operators have exclusively exempt wells in their portfolios versus how many operate both exempt and non-exempt wells. EDF grouped operators into the following categories:

A. Category 1: Operate with exempt and non-exempt wells in their portfolio.
B. Category 2: Operate with only exempt wells.

Using this information on the types of wells in each operator's portfolio EDF compared the cost of conducting quarterly inspections for Category 1 and Category 2 wells to the total revenue from all wells each operator's portfolio. EDF estimates quarterly inspections cost $1,658 per well, based on EPA calculations and reported data in annual emission reports. To calculate per-well revenue, EDF examined monthly oil and gas prices per unit sold combined with well production in barrel of oil equivalent terms using 2017 data. EDF then estimated the LDAR cost burden to each category of operators by estimating the mean well revenue for each operator in each category, calculating the median per well revenue across all operators in each category. EDF assessed the LDAR cost burden as a share of the median well revenue for operators in each category.

EDF also calculated total VOC and CH4 reductions associated a quarterly inspection requirement at all Category 1 wells.

Using this approach, we recommend that all Category 1 operators conduct quarterly inspections of the wells in their portfolio. This would reduce methane emissions by 421,510 tons of CH_4 and 43,455 tons of VOCs[91] at a cost of only approximately 1.6% of annual revenue for those operators.[92] At $1,658 per inspection, this approach is highly cost effective and results in a cost/benefit of $3.58 per Mcf of Ch4 reduced or or $7.44/mtCO2e reduced[93] and $1,626.39 per ton of VOC reduced.[94] Moreover, per well savings from quarterly LDAR covers roughly 25% of inspection costs for Category 1 operators.[95]

- *Alternative 2: Tiered Approach Based on Production*

As an alternative, we suggest DEP establish a tiered LDAR approach based on production. This is consistent with what Colorado has adopted and successfully implemented since 2014. The table below presents a tiered approach, based on production, and estimates total reductions

	Well Count	Tiered LDAR Reductions (tons CH4)	Tiered LDAR Reductions (tons VOC)
More than 15 BOE/d	2,435	304,609	31,403
5-15 BOE/d	626	11,574	1,193
Less than 5 BOE/d	64,483	132,229	13,632

[91] We used PA DEP's statewide methane to VOC ratio of 9.7:1 to calculate VOC reductions.
[92] Exhibit A.
[93] To calculate the cost savings, we applied a cost of $1,658 per well for Quarterly Inspections to the total number of wells.
[94] These estimates do not include savings from recovered gas. To estimate VOC reductions, we converted tons of methane using DEP's statewide methane to VOC ratio.
[95] *Id*. at Slide 23.

Total	67,544	448,412	46,228

This approach is also highly cost effective, falling well under traditional thresholds for cost effectiveness used by other states and EPA. Requiring annual inspections at wells that produce less than 5 BOE/d is highly cost effective at $183.37/short ton CH4 or $3.89/MCF CH4 and $1,778.73/short ton of VOC.

Requiring semi-annual inspections at wells that produce between 5 and 15 BOE/d can be done for a cost of $ 40.68 per short ton of Ch4 reduced and $ 394.56 per ton of VOC reduced.

Lastly, requiring quarterly inspections at all wells that produce over 15 BOE/d can be done for a cost of $12.02 per short ton of methane reduced and $116.63 per ton of VOC reduced.[96]

Colorado's LDAR program Demonstrates Inspections for Low-Producing Wells are Necessary to Reduce Leaks and Cost Effective

<u>Frequent surveys, including at low producing wells, provide significant benefits and are cost-effective</u>

Colorado's approach to low-producing wells underscores our alternative proposals for addressing emissions from low-producing wells. Colorado has required LDAR for wells, including low-producing wells, since 2014. Since then Colorado has repeatedly strengthened its requirements for low-producing wells based on data and experience demonstrating that frequent (at least semi-annual) inspections are cost effective for such wells.

Since initially adopting LDAR requirements, Colorado has twice strengthened them by increasing the inspection frequency for a suite of well sites with low production. First, in November 2017, the Colorado Air Quality Control Commission ("AQCC") increased the minimum inspection frequency for well sites based on a tiered schedule correlated to potential emissions. Then, in December 2019, after the close of the public comment period on EPA's Reconsideration Proposal, the AQCC further strengthened its LDAR rules to require at least semi-annual inspections for all well sites except for those with actual uncontrolled VOC emissions less than two tpy. More frequent inspections, either quarterly or monthly, are required for larger well sites. As a result, semi-annual or more frequent monitoring is now required at 3,103 of the 5,779 well production facilities in the state that have VOC emissions from the largest onsite storage tank of less than 12 tpy.[97] A significant percentage of these well production facilities are lower-producing, since tank emissions are directly correlated to production, and this subset of well sites constitutes those with some of the smallest VOC emissions from tanks in the state.

Further, new data continues to show that more frequent LDAR surveys are important to maintain the benefits of emissions reductions.[98] This study assessed the effectiveness of LDAR with repeat

[96] All cost effectiveness analysis based on the assumption that quarterly inspections cost $1,658 per well and do not include estimates of gas savings.
[97] Economic Impact Analysis, Colorado Dep't of Health and the Environment, Table 22 (Nov. 5, 2019).
[98] Ravikumar et al., *Repeated Leak Detection and Repair Surveys Reduce Methane Emissions Over Scale of Years*, Envtl. Research Letters (February 26, 2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/meta

optical gas imaging surveys at Alberta natural gas facilities. After one survey, total methane emissions were reduced by 44 percent, demonstrating the effectiveness of LDAR for mitigating emissions. Over 90 percent of detected leaks had been effectively repaired by the second survey, but fugitive emissions only decreased 22 percent due to the development of new leaks. Consequently, LDAR is highly effective at finding and fixing individual leaks, but repeat, frequent surveys are necessary to maintain low emissions.[99]

Colorado Strengthens its LDAR Rules

In 2014, the AQCC adopted LDAR requirements for well production facilities and natural gas compressor stations,[100] citing evidence that "leak frequencies decrease" when LDAR programs are implemented.[101] These rules, described in Table 1 below, set forth a tiered LDAR program where inspection frequency is tied to the actual uncontrolled VOC emissions from the largest storage tank at a well site; the greater the actual VOC emissions, the more frequent the inspections.[102] The initial rules required monthly inspections at those sites with tank VOC emissions over 50 tpy, quarterly for those well sites with tank emissions between twelve and 50 tpy, annual inspections for those well sites with tank emissions between six tpy and twelve tpy, and a one-time inspection for those well sites with less than six tpy of VOCs.[103]

In 2017 Colorado strengthened its LDAR rules for those well sites with less than twelve tpy VOC emissions from the largest storage tank onsite and located in the Denver metropolitan ozone nonattainment area. Specifically, for this class of well sites, Colorado increased the minimum inspection frequency to annual for those well sites with between one and six tpy of VOCs from tanks and instituted a baseline semi-annual inspection requirement for well sites with six or more tpy of VOC emissions.[104] The state retained the more frequent inspection requirements, either quarterly and monthly, as state-only requirements for those well sites in the highest tier of emissions (greater than 20 tpy for well sites with hydrocarbon storage tanks and 50 tpy for those without).[105]

Recently the Colorado AQCC strengthened for the second time its requirements for low producing wells, noting "more site visits results in the identification and repair of more leaks."[106] Specifically the AQCC increased the inspection frequency for the well sites emitting between two and twelve

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[99] However, emission reductions were greater for vented sources (47 percent) than fugitive sources (22 percent), especially for tank-related sources, which may be due to operators identifying malfunctions or design issues causing anomalously high vented conditions. Therefore, EPA underestimates the benefits of LDAR surveys by failing to account for the reduction in vented emissions.
[100] Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, 5 Colo. Code Regs. § 1001-9: XVII.F.4. (2014) ("2014 CO LDAR Rule").
[101] Regulatory Analysis, Colorado Dep't of Health and the Environment at 29 (Feb. 11, 2014).
[102] 2014 CO LDAR Rule at XVII.F.4.c. If a well site does not have tanks, the inspection frequency is tiered to the "controlled actual VOC emissions from all permanent equipment . . . ."
[103] *Id.* at Table 4. (2014).
[104] Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, 5 Colo. Code Regs. § 1001-9: XVII.F.4.c. Table 4 (2017) ("2017 CO LDAR Rule").
[105] *Id.*
[106] Regulatory Analysis, Colorado Dep't of Public Health and the Environment at 10 (Dec. 5, 2019), Exhibit E.

tpy of VOCs from tanks to semi-annual.[107] The AQCC retained the more frequent inspections, either quarterly or monthly,[108] for well sites with tank emissions greater than twelve tpy, and the annual inspection requirement for well sites with tank emissions between one and two tpy VOCs located in the nonattainment area.[109]

The state also adopted a wholly new requirement that requires more frequent inspections at well sites located near homes. Specifically, operators must inspect well sites located within 1,000 feet of an occupied area quarterly, rather than semi-annually, if VOC emissions are greater than two, but less than twelve.[110] Operators must conduct monthly inspections at well sites with greater than twelve tpy of VOC emissions.[111]

The AQCC determined that increasing the inspection frequency to semi-annual for those well sites with tank emissions greater than 2 and less than 12 was cost effective.[112] In particular, the AQCC estimated the cost of conducting semi-annual ongoing instrument based inspections at affected well production facilities to be approximately $1,340/ton of VOC and $742/ton of methane/ethane, based on net cost (including gas savings) and allocating all costs of control to each pollutant.[113] In comparison, in the Reconsideration Proposal, EPA estimated under its single pollutant approach, inclusive of gas savings, that semiannual OGI monitoring would cost $965/ton of methane reduced at non-low production sites and $1,396/ton of methane at low production sites, while costing $3,473/ton of VOC reduced at non-low production sites and $5,023/ton of VOC at low production sites.[114] Notably, Colorado's cost-per-ton estimates for semiannual monitoring are lower than the cost-per-ton estimates (with gas savings) of EPA's proposed changes to monitoring frequency: EPA estimates annual monitoring at non-low production sites will cost $781/ton of methane reduced and $2810/ton of VOC, and that biennial monitoring at low-production sites will cost $906/ton of methane reduced and $3,259/ton of VOC reduced.[115]

Other analyses submitted as part of the Colorado rulemaking record suggest these numbers are conservative. For instance, WZI, Inc.,[116] an expert engaged by EDF, concluded that Colorado's estimate did not reflect significant decreases in LDAR costs since 2014, noting that "[t]he cost of LDAR has fallen by about 30% since it was originally required in Colorado due to lower initial costs of equipment, availability of rental equipment and training programs, and general lack of inflation in oilfield services."[117]

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[107] Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, 5 Colo. Code Regs. § 1001-9: II.E.4.d. Table 3 (2019) ("2019 CO LDAR Rule").
[108] *Id*. at Table 3.
[109] *Id*. at I.L.2.a.
[110] *Id*. at Table 3.
[111] *Id*.
[112] AQCC Economic Impact Analysis for Regulation 7, Nov. 5, 2019, on file with EDF.
[113] *Id*. at 25.
[114] EPA, *Background Technical Support Document for the Proposed Reconsideration of the New Source Performance Standards 40 CFR Part 60, subpart OOOOa*, at 32 (Sept. 2018).
[115] *Id.* 30-31.
[116] EDF Rebuttal to Comments for Rulemaking on AQCC Proposed Revisions to Regulations Numbers 3 & 7, December 16-19, 2019 Hearing, Expert Report of Mary Jane Wilson, President of WZI Inc., Exhibit F.
[117] *Id*. at 3-4.

In sum, Colorado's experience underscores that frequent LDAR surveys at lower production well sites is necessary and important for securing additional pollution reductions and that frequent surveys are both feasible and cost-effective. Indeed, Colorado has moved forward with *strengthening* monitoring requirements at both new and existing facilities, in sharp contrast to EPA's proposal to weaken requirements currently in place. In particular, Colorado's recent estimates of the cost of methane and VOC abatement suggest that EPA has significantly overestimated the cost of monitoring.

DEP Must Strengthen the Alternative Leak Detection Method Provision

EDF strongly supports the ability of operators to use new and emerging technologies and techniques to detect leaks in their systems and facilities. However, the draft rule should be improved by adding the specific requirement that deployment of such technologies and techniques results in equivalent emissions reductions.

The current rule allows operators to use a Method 21 leak detector, optical gas imaging camera, or other leak detection approved by the DEP. We recommend the rule specify that an alternative leak detection device or method must achieve equivalent emission reductions as allowed devices or methods. In addition, DEP should issue guidance materials describing the process for applying for use of an alternative device or method and the information required to demonstrate equivalent emission reductions. This guidance document should apply to the General Permits for new sources as well as to the existing source rule.

The leak detection technology landscape is highly dynamic, with innovation happening in real time, for example through ARPA-E's MONITOR project and EDFs Methane Detectors Challenge project in partnership with seven large producers and other stakeholders. It is crucial for state rules to create space for innovative technologies, which may be able to deliver improved environmental performance at reduced cost. In 2015, Colorado adopted a rule and detailed guidance documents setting forth the specific elements an alternative leak detection technology must demonstrate, and the process by which such an alternative technology is reviewed and approved.[118] We urge the DEP to adopt similar criteria, accompanied by clear and transparent instructions, governing the necessary elements of an application for an alternative technology and the approval process. Such an approach will help catalyze a race to the top in technology, control costs for the regulated community and boost environmental outcomes.

Flares

DEP should increase the destruction removal efficiency of all flares used to control emissions from tanks, pumps at well sites, and centrifugal compressors to 98%. Colorado and Wyoming similarly require a 98% destruction efficiency for select sources.[119]

[118] CO Reg. 7, § XII.8.a; CDPHE, Procedures on AIMM Process, AQCC Regulation No. 7, p. 3 (July 6, 2015) (accessible at https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf).
[119] CO Reg. 7, I.D.3 (Storage Tank Control Strategy), II.C. (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), II.D. Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8; Wyo. Dep't of Envtl. Quality, Oil and Gas Production

In the rulemaking for GP-5 and GP-5A, DEP initially called for 98% control efficiency, stating: "[t]he proposed General Permits required 98% control efficiency which was based on the economic feasibility of combustion control devices, as shown in Appendix D – Cost Analysis for Combustion Control Devices. In addition, the Department demonstrated that at a combustion zone temperature of 1,600 °F a methane destruction of 98% is achievable."[120] However, in 40 CFR Part 60 Subparts OOOO and OOOOa, the operators have the option to purchase manufacturer-tested models, which require 95% VOC control efficiency. Therefore, DEP revised the methane, VOC, and HAP destruction efficiency required from 98% to 95% to enable the owners or operators to comply with the federal requirements and terms and conditions of the general permits using manufacturer-tested models.

A 98% destruction and removal efficiency or greater is common in state requirements. 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.[121] Wyoming similarly requires that combustion devices used to control emissions from tanks, separation vessels, glycol dehydrators, and pneumatic pumps meet a 98% control requirement.[122] North Dakota similarly 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.[123]

We urge DEP to require flares for tanks, pumps at well sites, and centrifugal compressors to operate with a destruction efficiency of at least 98%, which can typically achieve a destruction and removal efficiency in excess of 99.5 percent.[124] Doing so will ensure that the level of methane reductions expected are actually achieved while providing significant benefits to air quality.

Tanks

Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised Dec. 2018), available at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf

[120] DEP Technical Support Document, "General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A) and for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5), p. 48 (June 2018). http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=19616&DocName=04%20FINAL%20TECHNICAL%20SUPPORT%20DOCUMENT%20FOR%20GP-5%20%282700-PM-BAQ0267%29%20AND%20GP-5A%20%282700-PM-BAQ0268%29.PDF%20%20%3cspan%20style%3D%22color:blue%3b%22%3e%28NEW%29%3c/span%3e

[121] 5 CCR 1001-9 §§ XVII.C.1.c, XVII.D.3., XVII.G.

[122] Wyoming Oil and Gas Production Facilities, Ch. 6, Sec. 2 Permitting Guidance, 6-10 (requirements for statewide sources. Same control efficiency required for sources located in other parts of the state), Sept. 2013.

[123] North Dakota, Bakken Pool Oil and Gas Production Facilities Air Pollution Control Permitting & Compliance Guidance, available at https://www.ndhealth.gov/AQ/Policy/20110502Oil%20%20Gas%20Permitting%20Guidance.pdf.

[124] U.S. EPA Office of Air Quality Planning and Standards (OAQPS), *Parameters for Properly Designed and Operated Flares*, 2-11, April 2012. https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf

DEP has proposed that all storage vessels located at unconventional well sites that were installed on or after August 10, 2013, and that have the potential to emit (PTE) more than 2.7 tpy of VOCs must control emissions by 95%. These same threshold and control requirements apply to storage vessels located at compressor stations in the gathering and boosting segment and storage and transmission segment as well as those located at processing plant facilities. This threshold is one area where the proposal goes beyond the CTGs, as the EPA recommended control threshold is 6 tpy of VOCs. Storage vessels located at conventional well sites and unconventional well sites that were installed prior to August 10, 2013, and that have a PTE greater than 6 tpy of VOCs must control emissions by 95%.

DEP's rationale for applying a lower, 2.7 tpy of VOCs at certain facilities is to prevent backsliding since DEP has required this level of control of storage tanks at unconventional well sites since August 10, 2013, pursuant to its well site permit Exemption 38.

We recommend utilizing the more stringent 2.7 tpy VOC threshold for all existing tanks.

Moreover, any applicability threshold should be set not for an individual tank, but rather for tank batteries.

Should DEP not take this approach, at bare minimum, DEP must define a storage vessel so that two or more physical tanks that are manifolded together to act as a single storage vessel are treated as a single unit for the purposes of determining applicability. Otherwise, operators will be incentivized to install multiple smaller tanks on a site to avoid having a single tank which exceeds the emissions threshold and is subject to the emissions standard. Of course, actual emissions in that case would be as high as from a single uncontrolled tank.

Certification of Control Devices

We further suggest DEP add a requirement that operators certify that their control devices (whether they be VRUs, flares or combustors) are adequately sized and operate in accord with the design in order to capture, convey and control emissions. 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.

Recent inspections by EPA and Colorado have revealed that inadequately designed and operated storage tank vapor control systems can result in very significant emissions. 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 directed 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 that covered over 3,400 tank batteries where regulations "relating to installation, operation, maintenance, design, and sizing of vapor control systems" were violated, resulting in excessive emissions.[125] U.S. EPA notes that "[I]mproperly or inadequately designed, sized, operated, or maintained vapor control systems can lead to uncontrolled emissions of [hydrocarbons]."[126]

In late 2016, EPA reached a consent decree settlement with Slawson Exploration, Inc., over violations at Slawson's storage tanks at approximately 170 facilities in the Bakken formation in North Dakota. Similar to the Noble settlement, the Slawson settlement "resolves provisions implicated by claims that Slawson failed to adequately design, operate, and maintain vapor control systems on its storage tanks at oil and natural gas well pads, resulting in emissions of [hydrocarbons]."[127]

Observations show that this problem is not limited to these two companies. A 2016 study reported results from helicopter surveys of thousands of wellpads. Almost 500 sites had emissions high enough to be detectable with the helicopter-mounted camera; at over 90% of these sites, the emissions were from a tank/tank source. In the Bakken, 14% of sites have detectable emissions,[128] even though many of these tanks are controlled. The authors of the helicopter survey paper report that "tank emission control systems commonly underperform."[129]

Recently implemented rules by EPA[130] and Colorado address this problem. Colorado's 2014 oil and gas rules were the first to require operators to inspect access points on storage tanks, such as pressure relief devices and thief hatches on tanks, monthly, quarterly or annually, depending on the amount of production at the facility.[131] In addition, 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 must 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;
- Have in place a procedure to update the storage tank system if capture performance is found inadequate;

[125] Noble Energy, Inc. Settlement (April 22, 2015), https://www.epa.gov/enforcement/noble-energy-inc-settlement
[126] *Id*.
[127] EPA, https://www.epa.gov/enforcement/slawson-exploration-company-inc-clean-air-act-settlement.
[128] Lyon, D.R., *et al*., (2016) "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environ. Sci. Technol*. **50**, 4877. http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705
[129] Lyon, D.R., *et al*., (2016), 4877.
[130] 42 C.F.R. § 0000a.
[131] 5 CCR 1001-9 § XVII.C.2

- Certify that they have complied with the requirement to evaluate the adequacy of their storage tank system.[132]

Similarly, EPA requires operators to submit a certification by a qualified professional engineer that closed vent systems used to reduce venting are properly designed to ensure that all emissions being controlled in fact reach the control device. EPA explains the basis for this requirement as follows:

> It is the EPA's experience, through site inspections and interaction with the states, that closed vent systems and control devices for storage vessels and other emission sources often suffer from improper design or inadequate capacity that results in emissions not reaching the control device and/or the control device being overwhelmed by the volume of emissions.[133]

We urge DEP to adopt a provision patterned on Colorado's and EPA's, that requires operators certify their facilities are designed and operated to meet reduction requirements.

Reporting requirements

We recommend DEP adopt a self-certification requirement that tracks reporting requirements, similar to requirements in Colorado and EPA regulations. This mechanism will provide a basis for enforcement actions due to false or inaccurate compliance reporting.

In Colorado, companies must submit semi-annual reports wherein a "responsible official" certifies the accuracy of the data.[134] The certification attests to the truth, accuracy and completeness of the statements and information in the report and certifies the data is based on information and belief formed after reasonable inquiry. The Clean Air Act also utilizes the "responsible official" concept. For example, any person required to have a permit must "submit to the permitting authority a compliance plan and an application for a permit signed by a responsible official, who shall certify

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[132] 5 CCR 1001-9 § XIX.N., Statement of Basis and Purpose (Feb. 23, 2014).
[133] 81 Fed. Reg. 35824, 35871 (June 3, 2016).
[134] Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7 Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, 5 CCR 1001-9. Colorado AQCC Reg. 3 defines "responsible official" as:
For a corporation: a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either: I.B.40.a.(i) The facilities employ more than two hundred and fifty persons or have gross annual sales or expenditures exceeding twenty-five million dollars (in second quarter 1980 dollars); or I.B.40.a.(ii) The delegation of authority to such representative is approved in advance by the Division; I.B.40.b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively; I.B.40.c. For a municipality, state, federal, or other public agency; either a principal executive officer, or ranking elected official. For the purposes of this section, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency; or I.B.40.d. For affected sources: I.B.40.d.(i) The designated representative in so far as actions, standards, requirements, or prohibitions under Title IV of the Federal Act or the regulations, found at Code of Federal Regulations Title 40, Part 72, promulgated there under are concerned; and I.B.40.d.(ii) The designated representative under Title IV of the Federal Act or the Code of Federal Regulations Title 40, Part 72 for any other purposes under the Code of Federal Regulations Title 40, Part 70.

the accuracy of the information submitted."[135] The Clean Air Act also provides that "[a]ny report required to be submitted by a permit issued to a corporation under this subchapter shall be signed by a responsible corporate official, who shall certify its accuracy."[136]

DEP Should Change the Title of the Rule in Recognition of the Governor's Commitment to Reducing Methane from Existing Sources

We recommend DEP change the title of this rule to "Control of Hydrocarbon Emissions from Oil and Natural Gas Sources." Doing so acknowledges the methane reductions that the proposed requirements will achieve, especially if strengthened, and the Governor's promise to reducing methane from existing oil and gas facilities.

As demonstrated above, this rulemaking will result in a substantial decrease in methane emissions. DEP's own estimates calculate the rulemaking will result in over 75,000 tpy in methane reductions. Adopting our recommended improvements will result in significantly greater methane reductions. Highlighting "VOC" in the title detracts from the resulting methane reductions.

The Pennsylvania DEP proposal tracks closely frameworks in other jurisdictions, such as the Colorado Air Quality Control Commission 2014 Oil and Gas rules. Specifically, DEP, like the Colorado AQCC, has proposed measures that reduce both methane and VOCs, and has only used a VOC threshold to trigger control requirements for one source: storage vessels. Pennsylvania also estimated methane, as well as VOC emissions, and noted the methane reductions as one of the goals of the regulation. For these reasons, it is appropriate that the title of the rule accurately reflect the rule's intent and practical effects and should accordingly be "Control of Hydrocarbon Emissions from Oil and Natural Gas Sources" rather than "Control of VOC Emissions from Oil and Natural Gas Sources."

Finally, methane meets the definition of "air contaminant," "air contamination," and "air pollution," in Pennsylvania's Air Pollution Control Act.[137] As such, limiting the title of the rule to VOCs detracts from the successful reduction in pollution the rulemaking will achieve.

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[135] 42 U.S. Code § 7661b(c). Federal regulations (40 C.F.R. 70.2) define "responsible official" as one of the following: (1) For a corporation: a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either: (i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or (ii) The delegation of authority to such representatives is approved in advance by the permitting authority; (2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively; (3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of EPA); or (4) For affected sources: (i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and (ii) The designated representative for any other purposes under part 70.

[136] 42 U.S. Code § 7661c(c).

[137] Pennsylvania Air Pollution Control Act, §3.

Conclusion

We greatly appreciate the opportunity to comment on this important rulemaking and thank DEP for its leadership on this critical issue.

Sincerely,

Dan Grossman
National Director of State Programs, Natural Gas
Environmental Defense Fund

Elizabeth Paranhos
Attorney Consultant

John Walliser
Senior Vice President, Legal & Government Affairs
Pennsylvania Environmental Council