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I. Introduction

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF") on the Texas Commission on Environmental Quality ("TCEQ") proposal to amend Chapter 115, Control of Air Pollution from Volatile Organic Compounds (VOC) RACT Rules for Oil and Natural Gas CTG. These comments contain EDF's recommended solutions for dramatically strenghtening the rule in order to ensure that it acheives much needed emission reductions from the 10,824 well sites[1] and other facilities affected by the proposal. Adoption of a robust rule to curb harmful VOC emissions from existing oil and gas sources in the Dallas-Fort Worth ("DFW") and Houston-Galveston-Brazoria ("HGB") ozone nonattainment areas is critically needed to improve air quality and ensure Texas complies with its Clean Air Act obligations. Notably, TCEQ's proposal is far from robust as it exempts the vast majority of well sites in the two nonattainment areas from the leak detection and repair requirement and requires only semi-annual or annual inspections at the remaining well sites. TCEQ's proposal also represents a missed opportunity to improve the efficiency of flares used to control storage tanks, pneumatic pumps and compressors by specifying a 98% destruction removal efficiency ("DRE") or control devices. Efficient flares with a 98% DRE are commerically available today, required in other jurisdictions and have the effect of mininizing the uncontrolled release of hydrocarbons.

Reducing VOC emissions from the oil and gas sources covered by the CTGs in the nonattainment areas represents only the most minimal step TCEQ must take to address air pollution from oil and gas sources. Venting, flaring and leaking emissions from oil and gas sources are a significant source of harmful climate-forcing methane pollution as well as ozone-forming VOCs. Swift action is urgently needed to reduce methane emissions in order to slow the pace of climate change. Accordingly, we urge TCEQ to:

(1) expediously adopt RACT that requires quarterly, comprehensive inspections toidentify leaks at well sites, and requires flares and combustion devices used to control tank, pump and compressor emissions to achieve a 98% destruction removal efficiency; and

(2) immediately propose a rule that requires deep cuts in methane emissions from new and existing oil and gas sources across the state.

A. 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.[2] Leaky, outdated, and malfunctioning equipment at oil and gas sites constitute a primary source of methane emissions.

Recent EDF analysis found that existing oil and gas sources in Texas are responsible for the release of 5,487,680 metic tons of methane and 1,873,033 metric tons of VOCs in 2019. This estimate is

[1] 2020 well site data provided by Enverus Prism (formerly DrillingInfo).

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

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.[3] These emissions contribute to harmful climate change that has already started impacting Texas.

Most of the state has warmed between one-half and one degree (F) in the past century. In the eastern two-thirds of the state, average annual rainfall is increasing, yet the soil is becoming drier. Rainstorms are becoming more intense, and floods are becoming more severe. Along much of the coast, the sea is rising almost two inches per decade. In the coming decades, storms are likely to become more severe, deserts may expand, and summers are likely to become increasingly hot and dry, creating problems for agriculture and possibly human health.[4] 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 Texas putting citizens and local industries at risk.[5]

In addition to contributing harmful pollution to the atmosphere, methane emissions also represent waste of a valuable resource. EDF estimates that the approximately 5.5 million tons of methane emitted to the atmosphere equates to 357 million cubic feet of natural gas that could otherwise be sold.[6] Reducing emissions from existing sources can result in significantly more gas being brought to market, to the benefit of Texas operators and citizens. Implementing common sense, economically sensible regulations is smart policy for the Lone Star state. We urge TCEQ to immediately develop a proposal to reduce methane from new and existing oil and gas sources and also to strenghthen its RACT proposal since RACT requirements reduce methane as a co-benefit.

II. Texas Must Act to Reduce VOCs from Existing Sources

The U.S. Environmental Protection Agency ("EPA") promulgated CTGs for oil and gas sources in October 2016,[7] triggering a statutory obligation for Texas to propose RACT for oil and gas sources by October 27, 2018. Section 182(b)(2) of the CAA provides that for moderate and above 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. TCEQ failed

[3] Production emissions are estimated for each year using two separate methods: total site-level emissions based on direct measurements and component-level emissions based on the EPA GHGRP. The difference between these two emissions estimates is attributed to 'abnormal process conditions', emissions that are difficult to quantify with bottom-up inventory based approaches.Total site-level emissions are estimated based on site-based measurements at 433 sites in six production areas (Barnett Shale, Fayetteville Shale, Marcellus Shale [Southwest PA/WV], Uintah County, Upper Green River Basin, and Weld County). Emission factors are correlated with yearly natural gas production and used to calculate a national emission total. Component-level emissions are calculated using GHGRP data for each year. Reported data are analyzed with a statistical model to extrapolate emissions from reporting GHGRP facilities to non-reporting facilities. For some sources, we use GHGRP activity data and other emissions data to estimate emissions. This approach yields source and state specific inventories for each year. For more details, please refer to Alvarez et al. 2018, https://science.sciencemag.org/content/361/6398/186.

[4] EPA, What Climate Change Means for Texas (Aug. 2016), https://www.epa.gov/sites/production/files/2016-09/documents/climate-change-tx.pdf

[5] *Id*.

[6] Lost gas calculated assuming that 80% of lost gas is methane.

[7] 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.

to propose RACT for existing sources by the October 2018 deadline. As a result EPA issued a finding of failure to submit and established a 24-month deadline for EPA to either approve of a SIP or finalize a Federal Implementation Plan for Texas.[8]

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 DFW and HBG nonattainment areas given the extremely degraded air quality in both areas and the significant VOC pollution oil and gas sources contribute. Leaks from well sites in the two nonattainment areas subject to the proposal emitted 19, 279 metric tons of smog-forming volatile organic compounds in 2017 alone, according to EDF's analysis.[9] 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.[10] 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.[11]

III. 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.[12] 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.

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[8] EPA, https://www.epa.gov/sites/production/files/2020-10/documents/placeholder_3.pdf

[9] To estimate methane and VOC emissions EDF identified well pads with production in 2020, located in either the Dallas-Fort Worth Ozone Non-Attainment Area (NAA) or the Houston-Galveston-Brazoria NAA, using data from Enverus Prism (formerly DrillingInfo). We classified wells as low producing ($<$ 15 barrels of oil equivalent per day (boed)) or non-low producing ($\geq$ 15 boed) based on their 2020 oil and gas production. They were further defined as (i) gas well site (gas-to-oil (GOR) ratio of $>$ 100 Mcf/barrel), (ii) oil well site with associated gas production (0.3 Mcf/barrel $<$ GOR $<$ 100 Mcf/barrel), and (iii) oil well site (GOR $<$ 0.3 Mcf/barrel). To estimate emissions from the well sites subject to the proposal we applied emission factors for each well site type using emission factors created from a study of site-level measurement data from over 1,000 sites in eight U.S. basins explained by Omara et al. (2018), Omara, M. *et al.* Methane emissions from natural gas production sites in the United States: Data synthesis and national estimate. (2018), https://pubs.acs.org/doi/10.1021/acs.est.8b03535. The Omara analysis utilizes these actual, site-level measurements to update fugitive emissions factors for the model facilities developed by EPA. We converted methane emissions to VOCs using EPA's standard conversion ratio of 3.6:1 tons CH4:VOC.

[10] 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.

[11] *Id*.

[12] IEA, Global Methane Emissions from Oil and Gas (Mar. 31, 2019), https://www.iea.org/articles/global-methane-emissions-from-oil-and-gas.

IV. Technical Comments

We suggest specific improvements to the rule below based on requirements adopted in other jurisdictions that, if adopted, will ensure Texas meets its CAA obligations to establish RACT for existing sources of VOCs. Notably, these suggestions are also equally applicable to methane emissions and should be included in any proposal to reduce methane emissions from new and existing oil and gas sources. 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 and will achieve the greatest emission reductions. Specifically, we propose:

(1) Requiring that all wellsites conduct quarterly, comprehensive inspections for leaks and monthly audio-visual-olfactory inspections;

(2) Increasing the destruction removal efficiency of all flares used to control emissions from tanks, pumps at well sites, and centrifugal compressors from 95% to 98%

A. Leak Detection and Repair

We recommend TCEQ require quarterly, instrument-based, comprehensive leak detection and repair (LDAR) for all existing well sites. 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 a significant source of methane and VOC emissions, per EDF's inventory. These sources contributed a total of 69,405 metric tons of CH4 and 19,279 metric tons of VOCs in 2020.[13]

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[14]—

[13] EDF estimate of emissions described in fn. 11.

[14] 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

and that existing inventories do not accurately reflect the presence of these "super-emitters."[15] Numerous studies undertaken in different basins in the U.S have underscored the need for frequent, if not continuous, LDAR.[16] Other studies have found that measured emissions exceeded estimates contained in emissions inventories, in one instance by as much as 50%.[17] 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.[18]

- ***Equipment leaks are unpredictable.***

Recent studies have assessed whether well characteristics and configurations can predict super-emitters, concluding that they are only weakly related,[19] 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.[20] 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."[21] 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.[22] 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

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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").

[15] Barnett Synthesis at 15599.

[16] *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).

[17] *See* Harriss.

[18] Zavala-Araiza, D., et al., (2017) at 12; see also Harriss.

[19] 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.").

[20] Harriss (2015)

[21] Zavala-Araiza (2015), at 8167−8174.

[22] 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.

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.[23] 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.[24] Other studies confirm these findings[25] and underscore the importance of frequent, 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.[26]

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.

i. TCEQ Should Require Quarterly Inspections to Reduce Leaks

[23] Barnett Synthesis at 15,600.
[24] *Id*.
[25] 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 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.
[26] Harriss, *et al*.

Other jurisdictions have successfully established regulations that require quarterly LDAR for existing sources including Colorado,[27] Wyoming,[28] California,[29] and Mexico.[30] A quarterly inspection schedule would put Texas operators on par with states such as California[31] as well as Wyoming[32] and Colorado.[33]

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.[34]

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.[35] 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.[36] 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.[37]

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[27] 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).

[28] 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

[29] 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

[30] 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.

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

[32] 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

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

[34] CARB § 95668(g).

[35] Colorado 5 C.C.R. 1001-9, Reg. 7, § C.II.E.4.d.

[36] *Id*. at XVII.a.5.

[37] WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6.

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.

ii. 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).[38] 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.[39]

ICF International. In 2015, EDF commissioned ICF to develop a stochastic model to estimate the cost-effectiveness of LDAR at different types of facilities.[40] 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

[38] 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.

[39] 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.

[40] ICF International. "Leak Detection and Repair Cost- Effectiveness Analysis." Prepared for Environmental Defense Fund. (December 2015). Slide 25, on file with EDF.

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).[41]

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.[42]

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.[43] 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.[44] Jonah's experience that gas savings from repairs often exceed the cost of performing repairs to identified leaks is also borne out by the Carbon Limits report[45] and analysis carried out by Colorado.[46] There is mounting industry-supplied evidence that frequent LDAR is cost-effective.[47]

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[41] 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.

[42] Center for Methane Emissions Solutions, Colorado Case Study, available at https://static1.squarespace.com/static/558c5da5e4b0df58d72989de/t/57110da386db43c4be349dd8/1460735396217/Methane+Study.pdf.

[43] 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), on file with EDF.

[44] Jonah Energy, Presentation at WCCA Spring Meeting at 16 (May 8, 2015), on file with EDF.

[45] 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.

[46] 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.

[47] 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). Rebuttals on file with EDF.

iii. TCEQ Should Require Operators to Inspect Pneumatic Controllers during LDAR Inspections.

TCEQ 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."[48] 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.[49] 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,[50] 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.

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.[51] 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.[52]

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48 Allen, *et al*. (2015).
49 Allen *et al*. (2013).
50 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.
51 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.
52 *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").

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.[53] 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.[54]

In response to this widespread problem, California's Air Resources Board, in their 2017 standards regulating greenhouse gas emissions from oil and gas operations,[55] 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,[56] and require checking all intermittent-bleed pneumatic controllers for improper continuous emissions during each inspection.[57] Controllers improperly emitting between actuation must be repaired.[58]

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[59]) must "directly measure" emissions from those controllers on an annual basis, and repair or replace any controller emitting more than six scf per hour.[60]

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

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[53] *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.".
[54] 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.
[55] 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.
[56] CARB 17 C.C.R. § 95669(a), (g).
[57] *Id.* § 95668(e)(3).
[58] *Id*.
[59] *Id.* § 95668(e)(2)(A)(1).
[60] *Id.* § 95668(e)(2)(A)(3), (4).

$36.43 per controller.[61] 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.[62]

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.[63] 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.

iv. TCEQ Should Remove the Low-Producing Well Exemption

Proposed new §115.172(a)(8) would exempt fugitive emission components located at a well site with one or more wells that produce, on average, 15 or less barrel equivalents or less per day. TCEQ's exemption has the effect of carving out 56% of the well sites in the DFW and HBG nonattainment areas from any inspection requirements, even minimal AVO inspections.[64]

Low-producing wells are the most abundant type of oil and gas well in the United States, and a surprising number of them are venting all of or more than their reported produced gas into the atmosphere.[65] This makes low-producing wells a disproportionate source of VOC and methane emissions compared to their energy production, and underscores the need for robust control requirements.

A 2020 study involving direct measurements of methane and VOC emissions from marginal oil and gas wells (wells producing less than 1 BOE/d) in the Appalachian Basin of southeastern Ohiofound that marginal wells are a disproportionate source of methane and VOCs relative to oil and gas production. The study estimated that oil and gas wells in this lowest production category emit approximately 11% of total annual methane production from upstream oil and gas sources in the EPA greenhouse gas inventory, although they produce about 0.2% of oil and 0.4% of all gas produced in the US per year.[66]

Another recent study involving site-level measurements of over 70 Permian Basin well pads found no relationship between emissions and production. Per the study, wells with production

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[61] 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.
[62] *Id*, p. 2.
[63] CO Reg. 7, § III.F.2.
[64] EDF, Pennsylvania Low-producing Well Technical Analysis (Exhibit A).
[65] Deighton, Jacob A. et al., *Measurements show that marginal wells are a disproportionate source of methane relative to production*, 70(10) J. AIR & WASTE MGMT. ASSOC. 1030 (Aug. 2020).
[66] Deighton, J.A. et al., *supra* n. 2.

below 10 barrels of oil equivalent per day had similar emissions as non-marginal wells, based on a comparison of absolute methane emissions and gas production by site.[67]

A 2018 study of sites in eight basins across the US is in accord. Researchers obtained site-level methane emissions data from over 1000 natural gas production sites, including 92 new site-level methane measurements in the Uinta, northeastern Marcellus, and Denver-Julesburg Basins, to investigate methane emissions characteristics and develop a new national methane emission estimate for the natural gas production segment. The study looked at natural gas production sites and categorized them as low (sites producing <100 Mcfd), intermediate (100 to 1000 Mcfd), and high (>1000 Mcfd). Low natural gas production sites accounted for 85% of the total number of sites in the study yet they accounted for nearly two-thirds (63%) of the total methane emissions.[68]

These studies demonstrate that controlling low producing wells is essential to curbing emissions from oil and gas facilities.

v. Colorado's LDAR program Demonsrates 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. [69] A significant percentage of these well production facilities are lower-producing, since tank

[67] Robertson, Anna et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions are a Factor of 5 – 9 Times Higher Than US EPA Estimates*, 54 ENVTL. SCI. & TECHNOL. 13926 (Oct. 2020). Measurements were taken in 2018.
[68] Omara, M. et al., *Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate*, 52 ENVTL. SCI. TECHNOL. 12915 (Sept. 2018). Low production sites accounted for only 9.6% of total natural gas production.
[69] Economic Impact Analysis, Colorado Dep't of Health and the Environment, Table 22 (Nov. 5, 2019).

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.[70] This study assessed the effectiveness of LDAR with repeat 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.[71]

Colorado Strengthens its LDAR Rules

In 2014, the AQCC adopted LDAR requirements for well production facilities and natural gas compressor stations,[72] citing evidence that "leak frequencies decrease" when LDAR programs are implemented.[73] 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.[74] 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.[75]

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.[76] 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).[77]

[70] 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
[71] 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.
[72] 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").
[73] Regulatory Analysis, Colorado Dep't of Health and the Environment at 29 (Feb. 11, 2014).
[74] 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 . . . ."
[75] *Id.* at Table 4. (2014).
[76] 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").
[77] *Id.*

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."[78] Specifically the AQCC increased the inspection frequency for the well sites emitting between two and twelve tpy of VOCs from tanks to semi-annual.[79] The AQCC retained the more frequent inspections, either quarterly or monthly,[80] 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.[81]

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.[82] Operators must conduct monthly inspections at well sites with greater than twelve tpy of VOC emissions.[83]

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.[84] 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.[85] 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.[86] 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.[87]

Other analyses submitted as part of the Colorado rulemaking record suggest these numbers are conservative. For instance, WZI, Inc.,[88] an expert engaged by EDF, concluded that Colorado's

[78] Regulatory Analysis, Colorado Dep't of Public Health and the Environment at 10 (Dec. 5, 2019), on file with EDF.
[79] 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").
[80] *Id*. at Table 3.
[81] *Id*. at I.L.2.a.
[82] *Id*. at Table 3.
[83] *Id*.
[84] AQCC Economic Impact Analysis for Regulation 7, Nov. 5, 2019, on file with EDF.
[85] *Id*. at 25.
[86] 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).
[87] *Id.* 30-31.
[88] 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 001, on file with EDF.

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."[89]

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.

vi. Quarterly inspections at well sites in the DFW and HBG Nonattainment Areas is Cost Effective

EDF calculated the cost effectiveness of requiring operators to inspect for leaks at all well sites, both low-producing and otherwise, in the DFW and HBG ozone nonattainment areas. To estimate the cost effectiveness of inspections EDF relied on its inventory of 2020 emissions, discussed above. We used the EPA's fugitive percent reduction numbers for each monitoring frequency, specifically, 80% reduction for quarterly monitoring. We estimate the cost burden of quarterly inspections by assessing the LDAR costs per well as a share of the median well revenue for each category. We use an LDAR cost estimate of $1,658 for quarterly inspections. These estimates are based on EPA's Technical Support Document calculations for the proposed reconsideration of OOOOa. [90] EPA estimated $1,167 per well for semi-annual LDAR at natural gas well sites, using optical gas imaging. We scaled this estimate down to reflect shorter inspection times as reported in Air Emission Reports (AERs) submitted to EPA and analyzed in an M.J. Bradley and Associates report.[91] This analysis finds that the EPA calculations may overestimate LDAR costs by between $300-$375 per well for semi-annual LDAR. We use the midpoint of a $338 overestimate to calculate our per-well LDAR cost value.

Per our analysis, we estimate that quarterly inspections can be accomplished for a cost of $1,164 per metric ton of VOC reduced and $323 per metric ton of methane at all well sites. Broken out by production, quarterly inspections at low-producing wells are still highly cost effective at $2,557 per metric ton of VOC reduced and $710 per metric ton of methane. The average cost of inspecting a well site with production at or above 15 BOE/d is a mere $683 per ton of VOC reduced and $190 per metric ton of methane.

Quarterly inspections at well sites in both nonattainment areas will reduce VOC emissions by 15,423 metric tons annually and reduce methane emissions by 55,524 metric tons.

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[89] *Id*. at 3-4.
[90] https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-0040
[91] MJB&A report. December 2018.Appendix E: Analysis of OOOOa Annual Air Emissions Reports.

Table 1. Cost Effectiveness of Quarterly Inspections at Well Sites in the DFW and HBG Nonattainment Areas

NAA	Site Type	Fugitive CH4*	Fugitive VOC*	CH4 Reductions**	VOC Reductions	$/ton CH4 reduced	$/ton VOC reduced
DFW	Low producing	16,118	4,477	12,894	3,582	665	2,395
DFW	>15 boe/d	48,746	13,540	38,996	10,832	182	654
DFW	All	64,863	18,018	51,891	14,414	302	1,086
HGB	Low-producing	1,678	466	1,342	373	1,143	4,114
HGB	>15 boe/d	2,864	795	2,291	636	330	1,188
HGB	All	4,541	1,262	3,633	1,009	630	2,269
DFW+HGB	Low-producing	17,796	4,943	14,236	3,955	710	2.557
DFW+HGB	>15 boe/d	51,609	14,336	41,287	11,469	190	683
DFW+HGB	All	69,405	19,279	55,524	15,423	323	1,164

* VOC and CH4 estimates in metric tons

** Reductions in metric tons. VOC reductions estimated by converting metric tons of CH4 to metric tons of VOCs using EPA's standard ratio of 3.6 tons of CH4 to 1 ton of VOC for produced gas

B. Flares and Combustion Devices

TCEQ should increase the destruction removal efficiency of all flares and combustion devices 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.[92]

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

[92] 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 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

destruction efficiency of at least 98% for hydrocarbons.[93] Wyoming similarly requires that combustion devices used to control emissions from tanks, separation vessels, glycol dehydrators, and pneumatic pumps meet a 98% control requirement.[94] 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.[95]

We urge TCEQ 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.[96] Doing so will ensure that the level of methane reductions expected are actually achieved while providing significant benefits to air quality.

V. Conclusion

We appreciate the opportunity to comment on this important rulemaking and urge TCEQ to adopt our recommendations. Specifically, to meet its CAA obligations and ensure the degraded air quality in the DFW and HBG nonattainment areas improves, TCEQ must strenghten the LDAR, tank, compressor and pump requirements in its RACT proposal. In addition, TCEQ must immediately propose a robust, comprehensive rule to limit methane emissions from new and existing oil and gas sources throughout the state to help combat the warming of the atmosphere that is adversely impacting the health and welfare of the citizens of Texas.

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93 5 CCR 1001-9, Pt. D, §§ II.F,III.D.3,II.C.1.c.

94 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.

95 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.

96 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