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February 8, 2019

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VIA EMAIL

Dear Ms. Papageorgiou:

## I. Introduction

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF"). EDF is a national membership organization with over two million members residing throughout the United States and nearly 200,000 residing in the state of New York who are deeply concerned about the pollution emitted from oil and natural gas sources.

We previously submitted comments to the New York Department of Environmental Conservation ("DEC") summarizing the latest science regarding measured methane emissions from oil and gas sources and best practices to reduce such emissions. The following comments elaborate on that prior submission. In particular, we recommend specific emission reduction approaches to mitigate emissions from well sites, compressor stations, and distribution facilities based on leading requirements adopted by other jurisdictions.

## II. Technical Comments

### *A. Leak Detection and Repair (LDAR)*

#### 1. Ongoing, Quarterly Inspections Represent Best Practice for Reducing Leaks due to Improperly Operating and Worn Out Equipment

As we discussed in our prior submissions,[1] independent research across the United States has shown that emissions at oil and gas sites from leaks, broken or worn out equipment, and improper operations are substantial and greatly underestimated in inventories. Regular, quarterly LDAR is needed to mitigate these unnecessary and harmful emissions and can be implemented for a reasonable cost.

A recent synthesis of the U.S. studies conducted over the past six years concluded that U.S. production emissions are 60% higher than inventories suggest.[2] Data for this study included measurement of emissions from over 400 individual well pads in six different US basins, validated against "top-down" airborne measurements of emissions from nine oil and gas producing basins. The authors of this synthesis study, as well as the underlying studies analyzed in the synthesis paper, include academics from twenty-five different research institutions. These scientists have concluded that the substantial extra emissions observed in these studies, compared to official inventories, likely arise from improper and abnormal operating conditions at the site level that are best addressed by frequent, if not continuous, inspections.
The scientific evidence suggests strongly that leaks arise randomly across equipment types and facilities, and that a small percentage of these leaks account for a large percentage of emissions. This information strongly supports an LDAR requirement grounded in ongoing, frequent, inspections, if not continuous monitoring, so that big leaks are identified as quickly as possible and mitigated. The lower the frequency of site inspections, the longer a potential leak may emit pollutants into the atmosphere. Moreover, because leaks occur randomly, it is important that all sites are inspected routinely. For these reasons, we urge the DEC to require ongoing, quarterly inspections at well sites and compressor stations.

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[1] EDF comments submitted to DEC on August 3, 2018
[2] Alvarez, et al., "Assessment of methane emissions from the U.S. oil and gas supply chain" Science, June 2018, http://science.sciencemag.org/content/early/2018/06/20/science.aar7204.full.

2. Quarterly Inspections Represent the Best Practice, and is Required by Multiple Jurisdictions

A number of jurisdictions require ongoing, quarterly inspections.

- **Mexico** recently promulgated a national rule that applies to onshore and offshore facilities, including production, compression and processing facilities, that requires quarterly instrument-based inspections.[3]
- **California** recently finalized a rule requiring 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.[4]
- **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.[5] The size of the facility is determined based on the potential to emit volatile organic compounds (VOCs), although operators are required to repair all hydrocarbon leaks, including leaks from components that primarily emit methane.[6] 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 four tons of VOCs from fugitive components.[7] Like Colorado, operators in Wyoming may use either Method 21 or an optical gas imaging instrument, or other approved instrument.

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[3] ASEA/SEMARNAT rule available at https://www.dof.gob.mx/nota_detalle.php?codigo=5543033&fecha=06/11/2018; English translation on file with EDF.
[4] California Air Resources Board ("CARB"), 17 C.C.R. § 95668(g).
[5] Colorado Air Quality Control Commission, 5 C.C.R. 1001-9, Reg. 7, § XVII.F
[6] Id. at § XVII.a.5.
[7] WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6.

3. Quarterly Inspections are Cost Effective

Information from various U.S. jurisdictions and independent consulting groups demonstrates that quarterly inspections are highly cost effective.

- **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-Julesburg 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.[8] Colorado determined that requiring quarterly inspections for compressor stations is cost effective, estimating a control cost of $2,273 per ton of VOC reduced.[9]

- **California**. The California Air Resources Board (CARB) has found conducting quarterly inspections at production facilities to be highly cost effective. CARB estimates the costs are $23 per metric ton of $CO_2$e reduced (accounting for savings from recovered product) to $26 per metric ton of $CO_2$e reduced (not accounting for savings).[10] These estimates assume a 20-year global warming potential for methane.

- **Carbon Limits Study**. This study is based on actual leak data from over 4,000 LDAR 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 $CO_2$e using a global

[8] 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.
[9] Colorado Air Pollution Control Division, Economic Impact Analysis (Final) for Regulation 7, Sections II., XII., XVII., XVIII. p.5 (October 4, 2017).
[10] 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.

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).[11]

- **Center for Methane Emissions Solutions**, **Colorado Case Study**. CMES interviewed 10 companies in Colorado operating after Colorado adopted its LDAR 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.[12]

- **ICF.** ICF developed a complex model to investigate the distribution of LDAR cost profiles at well sites (Attachment 1). This 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. These results further demonstrate that quarterly monitoring is cost-effective. ICF's estimate of the control costs for quarterly LDAR 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.[13] The attached power point describes the modeling concepts and model inputs in greater detail.

- **Industry**. Jonah Energy—an operator in the Upper Green River Basin in Wyoming—has expressed its support of at least quarterly instrument-based inspections,[14] noting that it already complies with the proposal because "each month, Jonah Energy conducts infrared camera surveys using a forward-looking infrared camera ("FLIR") camera at

[11] 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.
[12] Center for Methane Emissions Solutions, Colorado Case Study, available at https://static1.squarespace.com/static/558c5da5e4b0df58d72989de/t/57110da386db43c4be349dd8/1460735396217/Methane+Study.pdf.
[13] We converted ICF's cost effectiveness estimates into dollars per short tons of methane.
[14] Jonah Energy stated: "We support the [recent Wyoming rule for existing sources in the UGRB], as proposed, with some minor suggested changes [to the proposed tank requirements] outlined below." 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 Permit by Rule for Existing Sources (April 13, 2015).

each of our production facility locations."[15] 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.[16] Jonah has reported that this highly cost-effective quarterly 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.[17] 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[18] and analysis carried out by Colorado.[19] There is mounting industry-supplied evidence that frequent LDAR is cost-effective.[20]

4. Experience Demonstrates the Importance of Requiring Ongoing, Frequent Inspections

Information from Colorado underscores the importance of requiring operators to inspect for leaks routinely over time.

Inspections done by the Colorado Air Pollution Control Division and U.S. EPA of storage tank controls revealed very significant excess emissions caused by the improper design and operation of storage tanks and tank controls. These inspections led to the imposition of millions of dollars in fines to operators as well as regulatory reform. A key aspect of Colorado's regulatory reform is an inspection requirement for storage tanks, which includes monthly and quarterly inspections for facilities that have uncontrolled VOC emissions of at least 12 tons per year from storage tanks.

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[15] *Id*.
[16] 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).
[17] Jonah Energy, Presentation at WCCA Spring Meeting at 16 (May 8, 2015).
[18] 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/.
[19] 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.
[20] 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).

LDAR is effective at detecting abnormal operating conditions such as improperly operating tank controls or malfunctioning pneumatic controllers. Inspections and enforcement actions by the EPA and the state of Colorado confirm the findings of the helicopter study. In 2012, the Colorado Air Pollution Control Division and EPA inspected 99 storage tank facilities. They discovered that emissions were not making it to their intended control devices at 60% of the facilities, due to inadequately designed and operated storage tank vapor control systems. These inspections formed the basis for a $73 million settlement between Noble Energy, the U.S. EPA and the state of Colorado wherein the operator, in addition to paying a $4.95 million fine, agreed to a suite of measures to better reduce flash emissions and ensure the proper operation of tank controls.[21] More recently, EPA and Colorado entered into a second settlement agreement with another operator in Colorado, PDC Energy Inc., to address the same problem. Pursuant to this settlement, PDC agreed to implement $18 million worth of mitigation actions to address excessive venting from its tanks. These actions include engineering evaluations of its vapor control systems, periodic infrared ("IR") camera inspections, and the installation of pressure monitors with continuous data reporting to verify that over-pressurized tanks are not contributing to excess emissions.[22]

In 2014, Colorado implemented a suite of rules to address the problems identified in the Noble and PDC settlements. These rules included periodic instrument-based inspections at production facilities with tanks, analysis of the design of storage tank control equipment, and lowering the statewide emission threshold for installing controls on tanks from 20 tons per year of VOCs to 6 tons per year.[23]

The Colorado experience underscores the importance of frequent inspections: leaks from storage tank systems can be very significant, and if undiscovered, can emit substantial pollution. Frequent inspections that apply to storage tanks as well as traditional components are critical to identify these types of "super-emitters."

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[21] Noble Consent Decree, https://www.epa.gov/enforcement/noble-energy-inc-settlement
[22] PDC Consent Decree, https://www.epa.gov/enforcement/pdc-energy-inc-clean-air-act-settlement#violations
[23] 5 C.C.R. 1001-9, Section XVII.C.1.b.

Additional information from Colorado underscores that frequent inspections result in a decrease in leaks. The Colorado Air Pollution Control Division conducted IR camera inspections at over 8,000 locations between 2013 and 2015. The Division reported a significant decrease in observable leaks and unintentional venting: in year one, the Division observed leaks and unintentional venting from 42% of facilities. In the last inspection conducted two years later, only 9% of facilities had leaks/unintentional venting. The Division concluded the project was effective at reducing unintentional venting and leaks, helped operators identify problems that led to such leaks and venting, and drove voluntary improvements intended to help prevent and identify leaks. According to the Division:

> The most direct impact of the project, although not fully quantifiable, is the immediate reduction or minimization of emissions to the atmosphere from well production facilities through timely notification and repair of identified sources of leaks and venting.
>
> The project was also useful in helping identify atypical or previously unknown issues, such as cracked tanks, flare fuel gas line leaks (underground emanating to surface), separator pressure relief venting (indicative of separator unable to overcome high gathering line pressure), as well as malfunctioning equipment designed to vent (pneumatic devices).
>
> Affected O&G operators/companies reported purchasing or increasing the use of IR cameras to find and prevent leaks/venting, transitioning to better materials or equipment (such as higher quality thief hatch seals/gaskets and PRVs), implementing best practices to help prevent leaks/venting, and focusing on tank system design and operations analysis.[24]

Similarly, reports submitted by operators demonstrated that Colorado's LDAR program, which includes quarterly and monthly inspection requirements for medium and large well sites and compressor stations, has resulted in a decrease in leaks. Between 2015, when the program was

[24] CO Dept. of Public Health & Envn't APCD, Colorado Optical Gas Imaging Infrared Camera Pilot Project: Final Assessment, https://www.colorado.gov/pacific/sites/default/files/APCD_IRCameraProject_FinalAssessment.pdf

in full effect, and 2017, the number of reported leaks decreased by 52% percent, from 36,044 leaks in 2015 to 17,254 in 2017.[25]

5. <u>We urge the DEC to Include a Robust Alternative Compliance Pathway for Alternative LDAR Methods</u>

The field of leak detection technology is evolving rapidly. Emerging technologies and inspection methods, such as mobile mounted IR cameras and lasers, and continuous stationary monitors, have the potential to significantly cut down on inspection time while also increasing the speed at which leaks are detected. EPA, a handful of states including Colorado, Wyoming, and Pennsylvania, and the countries of Canada and Mexico have revised their rules and General Permits to include a provision that allows operators to request approval to use an alternative leak detection method or technology in order to provide a pathway for approval of these innovative approaches.

We urge the DEC to include a robust alternative compliance pathway in its rules that would allow operators to request approval to use an alternative leak detection technology or method to an IR camera or Method 21. Colorado's alternative compliance pathway provides a good example.

Colorado requires that an alternative method must be able to demonstrate it is capable of achieving emission reductions that are at least as effective as the emissions reduction achieved using an IR camera or EPA Reference Method 21.[26] In addition, the proposed alternative must be commercially available.[27] Applicants must provide detailed information on the alternative technology or method, including but not limited to, its limitations, the process for recordkeeping, whether it has been approved for other applications or by other regulators, and any modeling results or test data.[28] Colorado allows manufacturers of alternative instrument monitoring methods (AIMM) as well as operators to apply to use an alternative AIMM. Approved AIMM

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[25] CO Dept. of Public Health & Envn't APCD, LDAR Annual Reports, available at https://www.colorado.gov/pacific/cdphe/air/oil-and-gas-compliance
[26] *5 C.C.R. 1009-1* § XII.L.8.a(ii)(I); CDPHE, *Alternative AIMM Guidance and Procedures*, p. 1 (May 31, 2018) (accessible at https://drive.google.com/file/d/1reFIFX_DVl_Wcu82853NNekmhjOtljui/view).
[27] Id. at § XII.L.8.a(ii)(B); Alternative AIMM Guidance and Procedures, p. 2.
[28] Id. at § XII.L.8.a(i); Alternative AIMM Guidance and Procedures, p. 1.

may be used by any operator in Colorado to comply with well production facility and compressor station LDAR inspections. In addition, approved AIMM may be used to conduct inspections of pneumatic controllers in the Denver nonattainment area.[29] In Colorado, the application and approval process are subject to public notice and comment if the request is for use in the Denver metropolitan ozone nonattainment area. We urge the DEC to make all applications and approvals subject to public comment.

### *B. Pneumatic Controllers*

Pneumatic controllers vent natural gas as part of normal operation. Implementing rules that reflect best practices can significantly reduce these emissions at reasonable costs. Best practice, as demonstrated by rules in effect in California and Mexico, requires the use of no-bleed devices at new facilities, measurements of emissions from any natural-gas powered continuous controllers, and the use of no bleed devices at existing facilities, where feasible.

#### 1. Require the use of no-bleed technologies at new facilities and where feasible at existing sources

Technologies are available that can eliminate emissions from continuous and intermittent bleed pneumatic controllers. Specifically, operators can utilize zero-emitting controllers at facilities with access to grid or renewable power.

Instrument air systems and other inherently non-emitting sources, such as electric actuators, are feasible at many sites of facilities. Many sites have electricity available,[30] and at others, operators may be able to use other approaches to generate power, either for instrument air or for electric actuators. In instances where electricity is not available, operators can route emissions from continuous bleed devices to a closed loop system.

- **Grid connection**.[31] At sites that are connected to the electric grid, or with power available nearby, instrument air systems can replace gas-driven pneumatic controllers. For even modest facilities, instrument air is a low-cost option when power is available.

[29] Alternative AIMM Guidance and Procedures, p. 1.
[30] 5 C.C.R. § 1001-9, § XVIII.C.2.a.(ii).
[31] Alphabet Energy presentation at Natural Gas Star Annual Implementation Conference at 3, Nov. 18, 2015. Included here as an exhibit, will soon be posted on Gas Star website. Based on a survey of companies, 34% of companies in the U.S. report that their gathering compressor stations have grid access.

- **On-site generator**. Many sites produce power for on-site use using a natural gas-powered generator. Installing an instrument-air pneumatic system would be feasible in such cases. Beyond a traditional gas-powered generator, innovative technologies can bring electricity to remote sites. For example, thermoelectric generators are available that can be used to convert waste heat in compressor exhaust to electricity at remote oil and gas sites.[32]
- **Solar generator with battery storage**. Natural gas-driven devices can be replaced with electric actuators with low electricity requirements. Such devices are engineered by a variety of companies, and the technology continues to advance. One company has installed over 3,000 electric actuators at oil and gas sites in a variety of applications (dump valves, gas lift valves, separators, pressure valves, and compressor scrubbers).[33] In many geographic locations, the solar resources are sufficient to power these actuators.[34]

Electricity availability at sites is increasing while the power required for zero-bleed pneumatic alternatives is decreasing. As a result, many sites, both in the production and gathering and boosting segments, will be able to install zero-bleed pneumatic alternatives at low net cost. Several jurisdictions require or have proposed to require operators utilize zero-emitting technologies.

- **Colorado** requires the use of zero-bleed devices at all new facilities where "on-site electrical grid power is being used" and where such use "is technically and economically feasible."[35] While Colorado's requirement is limited to sites where grid power is in use, operators also can utilize solar or other non-grid sources of electricity to power pneumatic controllers.
- **CARB** requires all new continuous bleed controllers to be zero-bleed beginning in 2019. Operators can meet this requirement by either collecting all vented natural gas with the use of a vapor collection system or use compressor air or

[32] Alphabet Energy, Oil and Gas Products, *available at* https://www.alphabetenergy.com/product_category/oil-and-gas/.
[33] Exlar presentation at Natural Gas Star Annual Implementation Conference, November 18, 2015. Included here as an exhibit, will soon be posted on Gas Star website. Exlar. *Industries and Applications: Oil and Gas Industry*, *available at* http://exlar.com/industry/oil-gas-applications/, http://exlar.com/pdf/?pdf=/content/uploads/2014/10/Exlar-Eliminates-Methane-Emmissions.pdf
[34] *See, e.g.*, *id.* slide 16.
[35] 5 C.C.R. § 1001-9, § XVIII.C.2.a.(ii).

electricity to operate the device.[36] CARB estimates its rules are highly cost effective at $1 per metric ton of $CO_2$ reduced, including savings.[37]

- **Mexico** similarly requires operators install zero-bleed controllers at new facilities and retrofit existing controllers to be zero-bleed.[38] Operators may use compressed air, electricity or mechanic controllers to meet these requirements.
- **British Columbia** has proposed to require zero-bleed devices at new facilities.[39]

2. Require routine inspections of pneumatic controllers

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% 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."[40] Of the 40 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 standard cubic feet of gas per hour (scfh).[41] 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,[42] and of course the emissions factor

[36] California Regulation Order, March 2017, Section 95668(e)(2).
[37] Final Cost Effectiveness calculation, available at https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf (cost per ton calculated using 20 year GWP with Savings).
[38] SEMARNAT, ASEA rule, Chapter IV, Article 47 and 48.
[39] B.C. Oil and Gas Commission, Proposed Approach for Methane Regulatory Design, slide 16, https://www.bcogc.ca/node/15189/download
[40] Allen, *et al*. (2015).
[41] Allen *et al*. (2013).
[42] 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.

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 IR 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.[43] 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.[44]
- **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.[45] 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 Report**. The Carbon Limits Report confirms that pneumatic controllers often function improperly and vent at excessive rates.[46]

In response to this widespread problem, Colorado, California, Ohio and Mexico require operators inspect pneumatic controllers when conducting LDAR inspections.

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[43] 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.

[44] *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").

[45] *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.".

[46] 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.

CARB, in their 2017 standards regulating greenhouse gas emissions from oil and gas operations,[47] 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,[48] and require checking all intermittent-bleed pneumatic controllers for improper continuous emissions during each inspection.[49] Controllers improperly emitting between actuation must be repaired.[50] Colorado also requires operators inspect intermittent vent devices at intervals that correspond to required LDAR inspections.[51]

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.

3. Direct Measurement for Any Continuous Bleed Pneumatic Controllers

In those instances where the use of zero-bleed devices is not feasible, we urge the DEC to limit emissions to 6 scfh and require operators measure emissions annually to ensure that emissions remain below this threshold. Continuous-bleed devices, like intermittent-bleed devices, can emit in excess of design levels. It is important, therefore, that operators regularly inspect both such devices. California requires operators to inspect continuous-bleed devices annually using direct measurement.[52] Colorado also requires operators inspect continuous-bleed devices at intervals that correspond to required LDAR inspections.[53]

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[47] 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.
[48] CARB 17 C.C.R. § 95669(a), (g).
[49] *Id.* § 95668(e)(3).
[50] *Id*.
[51] 5 C.C.R. 1001-9, § XIII.
[52] California Regulation Order, March 2017, Section 95668(e)(2)(A)(3).
[53] 5 C.C.R. 1001-9, § XIII.

### *C. Pneumatic Pumps*

We urge the DEC to require new pneumatic pumps be no-bleed. The use of no-bleed pumps is technically feasible and cost effective. California, Canada and Mexico require operators use no-bleed pumps at new facilities.[54] Operators can meet these requirements by connecting the pump discharge emissions to a closed loop system, using electricity, or compressed air.
For existing pumps, we urge the DEC to require operators control emissions by routing to a process, a VRU, or a flare or combuster. Such a requirement is in line with rules for existing sources promulgated in Colorado, Wyoming, California, Mexico and Canada.

### *D. Liquids unloading*

We urge the DEC to propose a rule that requires operators of new and existing well sites to minimize the need for manual venting during liquids unloading activities by using best management practices and reducing emissions in those instances where manual venting occurs. Several jurisdictions regulate liquids unloading activities:

- **Pennsylvania** requires operators use BMPs including plunger lift systems, soaping and swabbing to conduct liquids unloading activities without venting. Where technically feasible and safe, operators must direct the gas generated during liquids unloading to a control device, a gas production line or existing controlled separator or storage vessel.[55]
- **Colorado** requires operators to use means of creating differential pressure to attempt to unload the liquids from the well without venting. Where venting occurs, operators must limit venting to the maximum extent practicable.[56]
- **Mexico** requires operators choose from a suite of BMPs including using plunger lifts, velocity tubing, foamers, surface pumping and bottom of well pumping to minimize emissions.[57]

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[54] CARB, Section 95668(e)(4); ECCC, Section 39 (1) (requiring pneumatic pump(s) that pump more than 20 litres of methanol daily on average over a month to operate without using natural gas); ASEA/SEMARNAT Rule, Art. 41.
[55] Pennsylvania Dept. of Env'tl Protection, Bureau of Air Quality, General Plan Approval and/or General Operating Permit, BAQ-GPA/GP-5A, Section L.1.
[56] 5 C.C.R. 1001-9, § XVII.H.1.
[57] ASEA/SEMARNAT Rule, Ch. VIII, Art. 66.

**Wyoming** requires operators to minimize emissions during liquids unloading.[58]

*E. Storage Tanks*

We recommend the DEC regulate storage tanks using an enforceable performance standard. As an example, Pennsylvania established a 2.7 Ton Per Year (TPY) of VOC threshold to control emissions from storage tanks. Pennsylvania requires new storage tanks to control VOC emissions in order to meet this limit[59], and has proposed the same control threshold for existing storage tanks.[60] CARB and Mexico have established a 10 metric ton of $CH_4$ threshold that applies to tanks and separators.[61]

We also urge the DEC to include a strict "no venting from access points during normal operation" prohibition and to require operators certify their tanks are adequately sized in order to capture, convey and control emissions. Finally, we strongly urge the DEC to include tanks in their LDAR program.

Recent inspections by EPA and the state of Colorado have revealed that inadequately designed and operated storage tank vapor control systems can result in very significant emissions.[62] Equipment must be designed to handle the pressure of liquids when transferred from separators to tanks. If the tank vapor system is not adequately sized to handle the peak surge of flash emissions that occur when pressurized liquids dump to the atmospheric storage tanks, then flash emissions do not make it to the control devices. Rather, access points on tanks designed to only open during emergencies or maintenance, such as thief hatches and pressure relief valves, open, releasing uncontrolled flash emissions to the atmosphere. In inspections of 99 storage tank facilities in Colorado's Denver-Julesburg basin in 2012, the Colorado Air Pollution Control Division and EPA found that emissions were not making it to their intended control devices at 60% of the facilities. These inspections formed the basis for the $73 million settlement between Noble Energy, the U.S. EPA and the state of Colorado discussed above.

Recently implemented rules in Colorado address this problem. Per the Colorado rules, venting from access points, such as thief hatches and pressure relief valves, on storage tanks is prohibited

[58] Wyoming Permitting Guidance at 13.
[59] Pennsylvania BAQ-GPA/GP-5A, Section E.
[60] Pennsylvania Proposed RACT Regulations for the Oil and Natural Gas Industry.
[61] CARB, 95668(a)(6); ASEA/SEMARNAT Rule, Ch. VII, Arts. 58, 59.
[62] Consent Decree U.S. v. Noble Energy, (No. 1:15 cv 00841, D. CO., April 22, 2015), available at http://www.justice.gov/sites/default/files/enrd/pages/attachments/2015/04/23/lodged_consent_decree.pdf.

during normal operations.[63] In addition, operators must develop a Storage Tank Emission Management (STEM) System plan. The purpose of this plan is to ensure that the storage tank facility is designed and operated properly to ensure that tanks operate without venting from access points during normal operation. Per the plan requirements operators must:

- Monitor for venting using approved instrument monitoring methods and sensory detection methods;
- Document any training undertaken by operators conducting the monitoring;
- Analyze the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;
- Identify the procedures to be employed to evaluate ongoing capture performance;
- Have in place a procedure to update the storage tank system if capture performance is found inadequate;
- Certify that they have complied with the requirement to evaluate the adequacy of their storage tank system.[64]

In finalizing the STEM requirements, Colorado found operators could meet the "no venting" requirement by installing buffer bottles on controlled tanks and complying with the STEM provisions, including frequent instrument-based monitoring for leaks at storage tanks. Colorado found installing buffer bottles and conducting monitoring to be highly cost effective at a mere $527/ton of VOC reduced.[65]

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

### *F. Compressors*

We recommend the DEC follow the approach taken in California and Canada regarding compressors. These jurisdictions require [annual] measurements of leaks from rod packing and wet seals and replacement of these if emissions exceed stated thresholds.[66]

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[63] 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.a.
[64] *Id*. at §§, XVII.C.2.b.; XIX.N., Statement of Basis, Specific Statutory Authority, and Purpose (Feb. 23, 2014).
[65] *Supra*, note 20.
[66] CARB 17 C.C.R §95668(c); ECCC Final Rule, https://www.canada.ca/en/environment-climate-change/news/2018/04/federal-methane-regulations-for-the-upstream-oil-and-gas-sector.html.

### *G. Dehydrators*

We recommend the DEC establish a 98% control performance standard to mitigate venting from glycol dehydrators, consistent with requirements promulgated by Colorado and Wyoming.[67]

### *H. Pigging*

Pipeline maintenance activities can result in significant emissions. We recommend NY follow the lead of Ohio and Pennsylvania and require operators use best management practices to reduce emissions from pigging as well as other pipeline maintenance activities.[68]

### *I. Distribution System*

We recommend that DEC include the natural gas distribution system in its regulation of methane from oil and natural gas sources. The Department has plenary authority and responsibility over environmental values under § 3-0301 of the Environmental Conservation Law, which gives the Department the responsibility to "to carry out the environmental policy of the state set forth in section 1-0101 of this chapter" (§ 3-0301(1)), specifically granting the Department the authority to adopt rules and regulations (§ 3-0301(2)(a)), to review and appraise programs of other state agencies and make recommendations (§ 3-0301(2)(b)), and to consult and cooperate with, inter alia, officials of other state agencies and other jurisdictions (§ 3-0301(2)(c)). With respect to air pollution control, under § 19-0301(1)(a) of the Environmental Conservation Law, the Department has the power to "[f]ormulate, adopt and promulgate… codes and rules and regulations for preventing, controlling or prohibiting air pollution in such areas of the state as shall or may be affected by air pollution and to include in any such codes, rules or regulations a general provision for controlling air contamination…" The Department's perspective is to be "comprehensive," insofar as the Department has the duty and responsibility, under § 19-

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[67] CO Reg. 7, § XVII.D.3; WY Permitting Guidance, 25 (requiring all new dehydrators to control emissions by 98%); Wyoming Nonattainment Area Regulations, Section 6(d)(1)(A); CO Reg. 7, § XVII.D.3.

[68] *See* Ohio Envtl. Prot. Agency General Permit 21.1.C.1.b., available at http://epa.ohio.gov/dapc/genpermit/ngcs/GP_171.aspx;*See also* Pennsylvania DEP General Permit 5A.K., available at http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=19615&DocName=02%20GP-5A%20UNCONVENTIONAL%20NATURAL%20GAS%20WELL%20SITE%20OPERATIONS%20AND%20REMOTE%20PIGGING%20STATIONS%20GENERAL%20PLAN%20APPROVAL%20AND/OR%20GENERAL%20OPERATING%20PERMIT.PDF%20%20%3Cspan%20style%3D%22color:blue%3b%22%3E%28NEW%29%3C/span%3E.

0301(2)(a), to "[p]repare and develop a general comprehensive plan for the control or abatement of existing air pollution and for the control or prevention of any new air pollution recognizing varying requirements for different areas of the state."

Methane emissions associated with the distribution system are a significant component of total methane pollution in the State. For example, we estimate that New York's natural gas systems local distribution segment emitted 25 Gg CH4 (2.15 MMT CO2e using a 20-year Global Warming Potential of 86). This value, which is based on allocating national emissions from the US EPA GHG Inventory (GHGI) proportional to the State's fraction of natural gas volumes delivered to customers (5.3%), is conservatively low since the underlying GHGI emission factors from Lamb et al 2015 likely underestimate the number of pipeline leaks. Moreover, best practices such as advanced leak detection technology and using advanced leak quantification methodologies can be cost effective. Using advanced leak detection to consider leak flow volumes for the prioritization of pipeline replacements can lead to both savings of lost gas, which has a value in itself, but also reduced numbers of leaks that would have to be investigated and repaired, incurring operation and maintenance costs. In addition to these two most obvious cases, advanced leak detection methodology and associated analytics can be used to improve efficiency of leak surveys that are taken on for a variety of reasons, whether targeting leaks that are likely to be hazardous, or surveying for potential new leaks that could occur after a disaster. A 2016 report by PricewaterhouseCoopers on new data analytics for utility asset management[69] includes a case study relating to a major gas distribution utility which sought to optimize its prioritization of capital replacement projects. In that study, the utility company used data gathered using mobile leak detection technology along with historical data to develop a predictive leak model. For a $15 million asset portfolio, this effort led to the following outcomes: an estimated 3.9 times more leaks avoided, 3.6 times greater leaks/mile replaced and 4.1 times more O&M expense cost savings for the same capital investment. Furthermore, in addition to improving the efficiency of capital replacement projects and capturing more gas, advanced leak detection and prioritization can save ratepayers money by avoiding costly leak abatement and response for leaks found as a result of odor calls and by first responders.

[69] PricewaterhouseCoopers, "A new view on pipeline risks: How spatial analytics can empower asset management for gas utility companies," April 2016, https://www.pwc.com/us/en/power-and-utilities/publications/assets/pwc_gas_pipeline_spatial_analytics_april_2016.pdf.

We recommend the DEC consider establishing quantitative emission reduction targets for abating environmentally significant leaks in distribution pipelines, setting a standard consistent with what would be achievable using best available control technologies. A 2016 Massachusetts statute provides a recent example of a state law expressly directing regulators to identify environmentally significant leaks and address them.[70] In addition, a 2014 California statute, SB-1371, envisions quantitative emissions reductions requirements, directing that multiple agencies work together to adopt rules and procedures that, inter alia, "establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction" and "provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components in those commission-regulated gas pipeline facilities that are intrastate transmission and distribution lines within a reasonable time after discovery, consistent with the California Global Warming Solutions Act of 2006…."[71] A performance standard based on best available control technologies would consider today's most advanced leak detection and advanced leak quantification techniques as a means of identifying and prioritizing distribution pipeline leaks, as described above.

## III. Conclusion

We greatly appreciate the opportunity to provide the DEC with comments and applaud the strong requirements proposed. Please do not hesitate to reach out to us with any questions.

Sincerely

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[70] *See* Massachusetts House Bill No. 4568 (2016), Section 13 ("The department of public utilities, in consultation with the department of environmental protection, shall open an investigation to establish specific criteria for the identification of the environmental impact of gas leaks… and to establish a plan to repair leaks that are determined to have a significant environmental impact.")
[71] *See* California SB-1371 Natural Gas Leakage Abatement (2013-2014), Section 2.

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