EARTHWORKS

February 20, 2020

Sandra Ely
New Mexico Environment Department
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Santa Fe, NM 87505
Comments submitted by email to methanestrategy@state.nm.us

Dear Ms. Ely and the Methane Advisory Panel:

Thank you for the opportunity to submit comments on the New Mexico Methane Advisory Panel draft technical report (issued in December 2019). The report's issuance is an important step on the path toward the state's goal of curbing climate pollution, including from the oil and gas industry.

I appreciated being part of the panel discussions and formulation of the report. On behalf of Earthworks, I am submitting the following comments on the report.

Earthworks is a national nonprofit organization committed to protecting communities and the environment from the impacts of mining and energy development while seeking sustainable solutions. For nearly 30 years, we have fulfilled our mission by working with communities and grassroots groups to reform government policies, improve corporate practices, influence investment decisions and encourage responsible materials sourcing and consumption.

Our comments are informed by the governor's mandate to NMED and EMNRD: *"...jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources and enact such rules as soon as practicable."*

In 2014, Earthworks started the Community Empowerment Project (CEP) because oil and gas pollution puts people and the climate at risk. CEP focuses on the use of optical gas imaging (OGI) to make visible otherwise invisible pollution caused by intentional releases, equipment failures, and operator errors in oil and gas fields. CEP's primary goals are to support frontline communities; shine a spotlight on the need for regulators, legislators, and companies to reduce pollution; and promote the improvement of oil and gas policies and regulations.

One of our strategies is to file complaints with regulatory agencies nationwide in order to drive industry and government accountability for fixing pollution problems. We have been heartened to see the New Mexico Environment Department (NMED) recently begin to use Earthworks' OGI and complaints as valid third-party evidence on which to base oil and gas investigations.

Such efforts are particularly critical now because methane pollution is 86 times more damaging to our climate than carbon dioxide over a 20-year time frame—which is only twice as long as the time that scientists say we have to avoid the most catastrophic effects of climate change.

Dedicated to protecting communities and the environment from the adverse impacts of mineral and energy development while promoting sustainable solutions.

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Oil and gas operations also release volatile organic compounds (VOCs) that cause a range of health problems, including benzene, a known carcinogen, and nitrogen oxide, which contributes to the formation of ozone. This directly threatens the nearly 140,000 New Mexico residents who live within a half-mile radius of active oil and gas facilities.

The following comments focus on several sections of the report and Earthworks' documentation of oil and gas pollution through OGI and Quantitative Optical Gas Imaging (QOGI), as well as our experience with methane control regulations in other states.

In addition, our comments are supported by input from James (Tim) Doty, President of TCHD Consulting LLC, with whom Earthworks has consulted on technical matters related to oil and gas air pollution and OGI. Mr. Doty is a former air scientist with the Texas Commission on Environmental Quality (TCEQ). He oversaw the agency's Mobile Monitoring Team's OGI program for ten years and served as its OGI Program Coordinator and certification instructor for another three years until his retirement from state service.

1. Emissions are likely higher than operator estimates suggest

A growing body of evidence underscores the importance of states like New Mexico requiring operators to reduce greenhouse gas emissions even more than their self-reported estimates suggest. This reality should underpin any future guidance on control technologies and practices, as well as agency monitoring, in order to help meet New Mexico's stated goal of reducing greenhouse gas emissions statewide by at least 45 percent by 2030.

The MAP report correctly states (p.14) that, "Care should be taken in estimating emissions" from the US Environmental Protection Agency Greenhouse Gas Reporting Program (GHGRP). Reasons cited include the combination of multiple states into Basin-wide numbers (i.e., New Mexico and Texas into the Permian) and the omission of countless wells and smaller facilities, including producers with lower volumes of reported emissions (under 25,000 metric tons per year of carbon dioxide equivalent, or CO_2e). Taken together, these "smaller sources" can cumulatively have a significant impact on both air quality and climate. By EPA's own estimates, the GHGRP stated coverage includes only about half of all greenhouse gas emissions and only 2,500 oil and gas facilities.

The report also reviews (pp. 37-41) studies indicating that actual measurements using a "top-down" approach show significantly higher levels of methane emissions than the GHGRP, which is based on "bottom up" estimates and operator self-reporting. The Panel should also be aware of a recently released study from Pennsylvania State University comparing actual measurement of methane plumes from oil and gas operations in the south-central US to the GHGRP inventory, which found that emissions are nearly twice as high as operators report.

Finally, previous research by Earthworks on gas facilities in Pennsylvania revealed a practice by operators of "mixing and matching" emissions factors for the purpose of applying for permits. In particular, the selection of certain emissions factors can keep Potential to Emit numbers low and allow for the classification of certain facilities as "minor sources"—when the selection of a different emissions factor for the same equipment would move the facility into the major source category.

2. Earthworks' field observations in New Mexico

Earthworks' field investigations have documented numerous pollution sources nationwide at more than 800 sites nationwide and internationally, including more than 100 in New Mexico. These comprise components and processes considered to be part of "normal operations" (e.g., engines and compressor stacks) and those that indicate operational problems and leaks (e.g., open thief hatches on tanks and unlit flares).

Since 2018, Earthworks has filed more than 100 complaints with NMED based on our OGI findings. Our field staff and certified thermographers conducted inspections largely in response to community requests from the Four Corners and Permian regions. We found significant oil and gas emissions at all types of sites—from new to old, large to small—and on both public and private land. We've prioritized complaints based on the size of the emissions plumes, proximity of the site to residential homes, and any odors or other health impacts detected by our field teams.

Examples of OGI videos of specific components are included in the relevant sections of these comments; a complete library of videos filmed in New Mexico is available at http://bit.ly/CEP-NM. The distribution of OGI observations of emission sources is a product of the prevalence of problems found in the areas we visit, combined with proximity and location factors that govern Earthworks' field activities. The tables below reflect the breakdown of observations nationwide and in New Mexico.

Field observations: nationwide

Emission source	Count	Percentage
Tanks	508	30%
Vent	263	16%
Flare	272	16%
Engine Stack	210	12%
Leak	128	8%
Unknown/Invisible	63	4%
Other	70	4%
Valve	43	3%
Stacks	47	3%
Compressor	34	2%
Pig	2	<1%
Pit	2	<1%
Drilling	4	<1%
Fracturing	4	<1%
Vehicles	5	<1%
Liquids Unloading	6	<1%
Pneumatic	7	<1%
Connector	22	<1%

Field observations: New Mexico

Emission Type	Count	Percentage
Tanks	103	40%
Vent	52	20%
Flare	31	12%
Leak	31	12%
Engine Stack	23	9%
Valve	8	3%
Connector	6	2%
Pneumatic	1	1%
Other	3	1%

3. Pneumatic controllers (Section 1)

In light of our comments above regarding actual emissions versus operator estimates, we note with some surprise that the MAP report indicates (p.21) that a high proportion (over 60 percent) of emissions are attributable to pneumatic controllers. Both Earthworks' and Mr. Doty's field experiences indicate there are considerably larger, more prevalent oil and gas emission sources, in particular storage tanks and flaring and venting (discussed below).

Nonetheless, current pneumatic controllers clearly represent a significant source of emissions that can and should be curtailed. We believe that no equipment should be allowed to vent on a regular and predictable basis, as is currently the case with pneumatic controllers.

OGI surveys and/or Method 21 inspections can actively pinpoint mechanical malfunctions for future repair and emissions minimization. However, even regular, frequent Leak Detection and Repair (LDAR) audits may not result in the reduction of emissions from pneumatics, since these components will often be deemed to be functioning as designed, i.e., to emit.

Given this, no emissions from pneumatics should be allowed. Federal New Source Performance Standards (NSPS) for methane and VOC control encourage the replacement of continuous bleed pneumatics. We recognize that newly constructed sites are more likely to be using low bleed or intermittent bleed pneumatic controllers. However, as noted in the MAP report (p. 21-22), it is possible to further reduce emissions from these devices by requiring zero-bleed controllers. California no longer allows installation of any continuous bleed pneumatic controllers, with British Columbia soon to follow suit.

We suggest that for all venting pneumatic controllers, a situation of "zero bleed" could be attained by routing exhaust back to the gas stream or to an enclosed flare, or electrifying the unit. The MAP report (pp.19-21) indicates that electrification is technically and economically feasible for all controllers, but a lack of grid electricity at well sites can hamper this option.

However, this analysis does not consider the range of voltages and amps that would be required for different types of venting pneumatic controllers if they were to be electrified, i.e., how much power is required for various controllers. For example, solar-powered generators could be used to run pneumatics; it is also possible that even a gas-based generator could result in lower emissions than continuous pneumatic releases. We therefore suggest that MAP revise its analysis to include electrical requirements for a range of controller types and sizes in order to determine electrification feasibility at off-grid sites.

Earthworks has observed leaking pneumatics in numerous locations; examples of OGI videos are in the table below.

Location	Emissions Source	OGI video
San Juan County	Pneumatic controller	https://www.youtube.com/watch?v=mDFJ0BA13FU&feature=youtu.be
San Juan County	Pneumatic controller	https://www.youtube.com/watch?v=KS6RAq_2TcY&feature=youtu.be
Rio Arriba County	Pneumatic controller	https://www.youtube.com/watch?v=buF3UGDwGhg&feature=youtu.be

In addition, we have quantified emissions from pneumatic controllers in New Mexico using the QL320 from Providence Photonics; these measurements are summarized in the table below.

Location	Emissions Source	Proxy Parameter	Leak rate (lbs/hr)
San Juan County	Pneumatic controller	Methane	0.2
San Juan County	Pneumatic controller	Methane	0.31
Rio Arriba County	Pneumatic controller	Methane	0.38
Rio Arriba County	Pneumatic controller	Methane	0.5
San Juan County	Pneumatic controller	Methane	2.1
San Juan County	Pneumatic controller	Methane	2.8

4. Leak Detection and Repair (LDAR) (Section 2)

Earthworks' experience with OGI in oil and gas fields nationwide has paralleled the development of LDAR requirements at the federal and state levels. As the MAP report describes (p. 35), OGI is widely considered as a Best System for Emissions Reduction, and is therefore a highly effective tool for use in site inspections based on LDAR.

In turn, LDAR is most effective as an emissions reduction strategy when it is conducted on a regular basis (e.g., quarterly as required by federal law) at a wide range of inspected locations (well sites, compressor stations, processing plants, metering and regulating stations, pigging stations, etc.). This is necessary because, as the MAP report points out (pp. 37-38), leaks can be heterogeneously distributed. Even seemingly "small" leaks can cause significant volumes of emissions and certain facilities can cause a disproportionate volume of emissions.

Earthworks' field observations support this. On many occasions, we have conducted OGI multiple times at the same sites and found the same operational problems and leaks, many of which appear "small" but can release dense, long plumes of pollution. Any emissions source that can be detected with OGI should be repaired. Similarly, OGI should be conducted even at low-producing wells since equipment and maintenance issues, not production levels, largely determine emission levels.

These realities underscore the conclusion in the MAP report (p. 40) that continuous vigilance by operators is needed to discover and fix leaks promptly so that they don't persist and become worse for extended periods of time. There is precedent for LDAR requirements based on frequent inspections and prompt repair schedules. Colorado requires monthly LDAR for certain major source facilities.[1] California's 2017 greenhouse gas emission standards for the oil and gas sector require operators to conduct repairs and replace equipment on lower-volume leaks in 14 days and on larger-volume leaks in as little as 2 days.[2]

We disagree with the statement in the MAP report (p. 34) that, "The largest sources of fugitive emissions are generally detected quickly without advanced detection tools. These events are usually detected by observable changes by operators conducting routine inspections using sight, sound and smell."

While sensory observations are a critical part of inspections, this is certainly not the typical, nor most reliable, way of detecting fugitive emissions. For example, there are severe limitations to hearing leaks if they are smaller or personnel are wearing hearing protection. Similarly, oil and gas sites produce many smells and olfactory fatigue and exposure issues can limit detection of leaks.

We support the point in the MAP report (p. 46) that companies can hire third parties to conduct LDAR. Regulators could also partner with third parties such as private consultants, academic institutions, and non-governmental organizations to detect and report emissions leaks and to complement an operator's required LDAR compliance schedules.

As noted in the report (p. 55), the TCEQ hires contractors for its helicopter flyover program, through which inspections are conducted over large geographic areas that include oil and natural gas activities. TCEQ then creates a spreadsheet with GPS coordinates and relevant OGI videos sorted by prioritization for action, after which regional offices conduct field OGI assessments to compare with aerial findings.

Earthworks takes issue with some of the assertions about the cost of conducting OGI as part of LDAR programs (pp. 45-47). New Mexico's primary goal should be requiring operators to comply with current and future regulations, not to skirt them because of purportedly high cost.

Following initial acquisition of an OGI camera, the cost of inspections can be quite low if they occur in conjunction with regular site inspections (e.g., for maintenance) or are done by on-site personnel. In other words, operators can avoid the long distances and high cost of travel for a single, specific OGI trip cited in the MAP report (p.27) through proper planning and coordination. Any financial impact analysis should consider LDAR not just as a "stand-alone" activity, but as an ongoing part of regular work.

In addition, since operators tend to own the majority of sites in a given region, they should be capable of conducting LDAR at many locations in a short period of time. Earthworks' OGI experience underscores this; in a single trip, our staff have been able to inspect as many as 25 sites within a 15-mile radius in a single day. We often encounter industry workers, even at remote locations—yet they do not have, nor seem familiar with, OGI cameras.

Also with regard to the cost considerations related to LDAR, the MAP report states (p.46 and p.63) that OGI cameras need to be calibrated annually. However, annual recalibrations are not required for Forward Looking Infrared (FLIR) gas finding cameras, the preeminent brand of OGI equipment**.** Annual calibrations are not required for FLIR OGI cameras unless the instrument is needed to collect accurate quantitative temperature measurements.

In addition, the report (p.60) states the high expense of conducting LDAR at marginal wells; however, the costs listed are based on OGI technical services, not Traditional Method 21 alternatives of sniffer instruments and soap bubble assessments, which could be options.

Finally, the report incorrectly states (pp.34-35) that, "the most commonly used leak detection equipment is an optical gas imager." Although federal regulations state that OGI is a BSER, it is clear that many companies still "officially" use sniffer instrumentation for LDAR activities rather than OGI. This is often the case because no video documentation is required via Traditional Method 21, and the timeline to complete maintenance activities is more flexible. In these cases, many oil and natural gas representatives appear to use OGI as a backup for maintenance protocols.

5. Compressors and Engines (Section 4)

The MAP report correctly emphasizes (p.92) that emissions from compressor stations reported to the GHGRP represent only a fraction of the likely actual emissions due to a lack of reporting for many smaller facilities. This underscores the importance of additional reporting and measurement by the state and operators at facilities that are large sources of both combusted and leaked emissions.

The MAP report states (p.84) that, "The primary source of methane emissions from compressors are from seals around the piston rod of a reciprocating compressor and around the spinning shaft of a centrifugal compressor," as well as (p.89) fugitive emissions from piping components.

It is certainly important that all components and seals be maintained to prevent leaks and, as the MAP report indicates (p.103, section 4.2) that wet seals be replaced with dry seals whenever feasible to reduce emissions. Cost should not be the driving factor behind this decision.

NMED and EMNRD should also address the intense releases from compressor stations that result from venting events, or blowdowns—whether scheduled to relieve pressure or unscheduled due to operational problems.

The oil and gas industry has acknowledged that emissions can greatly increase during events such as blowdowns, which can last for several hours but be most intense during the first 30-60 minutes.[3] In addition to releasing significant volumes of emissions, episodic emission events such as blowdowns have been confirmed by environmental health research to cause health impacts immediately or in as little as 1-2 hours, largely because toxicity is determined by the concentration of the chemical and intensity of exposure.[4]

We recommend the consideration of measures requiring that no gas from compressor blowdown vents be emitted to the atmosphere and that all blowdown gas be rerouted to a vapor recovery system or combustion device. According to the Natural Gas Star program, another mechanism of reducing emissions is to keep compressors fully pressurized when offline.[5]

6. Infrastructure planning (Section 5)

Earthworks strongly supports advancements in requirements for planning. As the MAP report acknowledges (p. 126), "a front-end investment in planning would presumably lead to additional natural gas capture and thus boost sales and profits." Planning for gas capture is in turn necessary to avoid flaring and venting, as discussed below.

Earthworks takes issue with the statement (p. 108) that, "over time, the necessary midstream and downstream infrastructure will ultimately be developed to accommodate long term production trends, but not without encountering periods marked either by bottlenecks or by excess capacity. Bottlenecks or capacity constraints are particularly relevant to and may result in periodic increases in flaring."

This statement is both inaccurate and backward-looking, reflecting the way the industry *has* operated—not how the industry *could* operate under a regulatory framework predicated on the minimization of waste and significant curtailment of methane emissions.

Further, this statement suggests that takeaway capacity is based upon expected production volumes. However, industry practice indicates the opposite: that takeaway capacity is based upon market demand, first, and only secondarily on expected well production capacities. Particularly in the associated gas context, this has meant that bottlenecks, and resulting venting or flaring, are the *expected* outcome, as producers are focused on oil or liquids production, and not the development and sale of gas. This view is confirmed by the discussion on p. 112 of the MAP report.

In addition, the MAP report notes (p. 113) that planning by midstream companies can inform producers of existing capacity, projected capacity additions, and capacity constraints. This can allow producers to respond proactively, such as by locating and timing development to coincide with projected available gathering capacity, or by pausing or slowing production.

To ensure that gathering capacity and production volumes of gas are generally matched requires more certainty in permit applications that takeaway capacity will be available when new wells begin production, i.e., through documentation of contracts or agreements indicating that the operator has obtained firm takeaway capacity from a midstream company.

Earthworks recommends that to enhance compliance, applications for permit to drill (APD) approvals should be deferred or denied if takeaway capacity plans are inadequate. To address changed circumstances, operators should also be required to update such plans when material changes occur, such as if drilling is delayed or more information becomes available about well characteristics.

We also note that the system of "well-by-well" permitting has created a planning gap with all other wells in the vicinity of the proposed well, including *existing* wells that may be venting or flaring and *new* wells that are planned to be developed by the operator. This gap should be addressed by requiring operators to package into a single application all planned, foreseeable drilling and infrastructure approval requests anticipated over a 6- to 12-month time period within a given field or unit based on geographic proximity or potential use of shared infrastructure such as gathering systems, compressor stations, or processing facilities.

The U.S. Bureau of Land Management tried this approach through Master Development Plans (MDPs), which demonstrate the utility of moving from well-by-well permitting to multi-well permitting in a developing field. Earthworks participated in such a process in southwest Colorado, and found the framework to be a workable one. Whenever and wherever new operations are allowed, states should require operators to put forth comprehensive drilling plans in order to avoid redundant infrastructure, which in turn can yield tremendous benefits in pollution reduction.

Earthworks has also participated in a Colorado Rule 216 process that provided for "Comprehensive Drilling Plans" and was intended to identify foreseeable oil and gas activities in a defined geographic area, facilitate discussions about potential impacts, and identify measures to minimize adverse impacts to public health, safety, welfare, and the environment, including wildlife resources, from such activities. This included consideration of such factors as the timing of well drilling, pipeline and processing plant locations, and emissions reduction technologies to be used for development proposals involving over 50 wells.

Earthworks supports the concept identified in the MAP report (p. 130) that under the Oil and Gas Act, (N.M. Stat. § 70-2-3) "surface waste" (i.e., emissions) management of gas is placed on an equal footing with "underground waste" management. This could be accomplished by requiring oil and gas lessees and operators to identify infrastructure investment and other actions they will take to prevent surface waste (e.g., emissions released through venting and flaring), in both their proposals for new well spacing and density and applications to increase well density and spacing. This would provide a basis for the Oil Conservation Division to consider and impose conditions to minimize surface waste in association with spacing and density decisions.

As noted in the MAP report (p.115), depending on size, midstream facilities (e.g., most compressor stations, gas plants, or oil terminals) require NMED air permits and any excess emissions during a routine or predictable startup, shutdown, or scheduled maintenance event must be reported (20.2.7.7 D. & 20.2.7.110 NMAC).

We support an expansion of this minimal regulation to ensure that operators plan their maintenance activities. By definition, a processor knows that planned maintenance activities are scheduled at compression stations or a processing plant or another permitted facility. A review of excess emissions reporting databases in Texas,[6] and more recently in New Mexico,[7] indicates that some facilities release excess emissions for planned maintenance. Therefore, we suggest that the agencies look at adding required technology upgrades for such facilities (see our points on compressor station blowdowns above).

The MAP report includes a number of potential examples of such technology. For example, the report references the Synapse report (p. 126), which discusses technology for Transmission Station Venting -Redesign Blowdown Systems/ESD Practices.

We support additional emission reduction measures described on pp. 140-141. In particular, these include Pennsylvania's requirement for the use of a pigging device with 95% control if emissions are 200 tpy of methane, or 2.7 tpy of VOCs; if emissions are less than these thresholds, operators must use best management practices to minimize liquids and emissions. In Ohio, operators must use an add-on pigging control which includes flare or vapor recovery to limit VOC emissions to 0.27 tpy, on average, over a rolling 12-month period.

Finally, the EPA's Natural Gas STAR program recommends saving the gas from compressors and/or pipeline segments that are taken out of service for operational or maintenance purposes, thereby reducing methane emissions by depressurizing to a connected or nearby low-pressure fuel or product system.

7. Flaring and venting (Section 6)

In the course of extensive field work, Earthworks has documented numerous instances of unlit flares at well sites in New Mexico (as well as on the Texas side of the Permian Basin). These observations are in line with growing awareness among regulators, policymakers, and environmental advocates of increasing rates of flaring and venting by operators. As the MAP report makes clear (p.112), these rates outpace growth in oil and gas production in New Mexico.

According to the most recently available data posted in the US Environmental Protection Agency's pollutant speciation database, natural gas flares can consist of over 60 percent methane, as well as ethane (also a greenhouse gas), propane, and a mix of other volatile organic compounds (VOCs).[8] Any state seeking to rein in greenhouse gas and VOC emissions must prohibit flaring and venting by operators; exceptions can be considered in limited cases where immediate safety to workers and surrounding residents is a concern.

Operators continually assert that insufficient takeaway capacity "forces" them to flare natural gas co-produced with oil. If this is indeed the case, it underscores the need for producers and midstream companies to do a far better job of coordinating well site and infrastructure planning (as discussed above).

At the same time, a series of recent studies focusing on the Permian Basin in Texas indicate that operators are releasing significant volumes of gas that they view as a "waste product." This is ostensibly because it's easier and cheaper to flare gas off that to capture, transport, and sell it at currently low prices—which is itself a consequence of lack of planning and overproduction. It is possible that operators in New Mexico are taking this same "burn it because it's cheap" approach.

Energy Intelligence, a global energy industry and policy think tank, published findings of a comprehensive review of records from both the Texas Railroad Commissions (RRC) and operators on flaring and venting. In short, RRC has been fast-tracking drilling permits and has never denied an operator's request to increase flare (despite laws ostensibly limiting the practice).

A study by Texas A&M University researchers compared emissions from flaring and venting in Texas RRC records with National Oceanic and Atmospheric Administration (NOAA) records from satellites detecting the practice. Both data sets show a rapid increase in emissions from the practice in recent years, but the NOAA data indicates levels double those claimed by operators. The researchers attribute this in part to a loophole allowing operators to skip reporting pollution from certain production practices.

Similarly, market research giant S&P Global has identified wide discrepancies in emissions from flaring between operator self-reported data and satellite measurements taken by federal agencies. A key S&P conclusion is that operators may be deliberately under-reporting pollution from flaring so they can keep producing oil unhindered by regulations that seek to rein in methane releases.

Earlier this year, an Environmental Defense Fund (EDF) analysis of reported versus measured flaring emissions concluded that twice as much natural gas is wasted in the Texas Permian Basin as industry claims. According to EDF, "Permian oil and gas operators burned enough gas to serve all the heating and cooking needs of the state's seven largest cities."

If NMED and EMNRD truly aim to reduce methane and VOC pollution, they should not accept a lack of planning by operators as an excuse for more flaring and venting. If takeaway capacity is truly the reason for additional flaring and venting, then the agencies should not approve additional well site permit applications that would result in gas flaring or venting. We support New Mexico's requirement that operators develop gas capture plans, and recommend that they also be required to ensure that gas capture is considered during infrastructure planning (discussed above).

Such stringency is critical because of the likelihood of underreported emissions data related to flaring and venting, as the MAP report emphasizes (pp. 116-121). According to the report, some operators may claim zero waste due to "reporting discrepancies," which could potentially cause total volumes flared and vented to appear lower than in actuality. NMED should clarify this discrepancy and be vigilant about any unusually low reported volumes when considering both restrictions on flaring and venting and more comprehensive reporting requirements.

Poor operator tracking and reporting could also mean that the gap between the rate of flared and vented gas and growth in gas production (p.116) is even larger than it seems—in turn posing even greater challenges for the state in addressing unnecessary releases of methane and other pollutants.

Earthworks' field observations of unlit flares also point to the likelihood that higher levels of emissions are being released than reported through malfunctioning flares that, because they are unlit, effectively serve as vent stacks. Examples of OGI videos of unlit flares in New Mexico are in the table below.

Location	Emissions Source	OGI video
Eddy County	Unlit flare	https://www.youtube.com/watch?v=u2yYXfuekDU&feature=youtu.be
Lea County	Unlit flare	https://www.youtube.com/watch?v=5i9yl0xfZ5Y&feature=youtu.be
Eddy County	Unlit flare	https://www.youtube.com/watch?v=QF8xwNeKSss&feature=youtu.be
Reeves County, TX	Unlit flare	https://www.youtube.com/watch?v=8ZZsQBfXoPI
Reeves County, TX	Unlit flare	https://www.youtube.com/watch?v=PRe6zsv7Ta4

In addition, we have quantified a significant volume of emissions from unlit flares in New Mexico and Texas (Permian Basin) using the QL320 from Providence Photonics; these measurements are summarized in the table below.

Location	Emissions Source	Proxy Parameter	Leak rate (lbs/hr)
San Juan County, NM	Unlit flare	Methane	25
San Juan County, NM	Unlit flare	Methane	41
Rio Arriba County, NM	Unlit flare	Methane	120
Reeves County, TX	Unlit flare	Methane	38.52
Reeves County, TX	Unlit flare	Methane	38.52
Reeves County, TX	Unlit flare	Methane	49.82
Reeves County, TX	Unlit flare	Methane	63.43
Reeves County, TX	Unlit flare	Methane	67.38
Reeves County, TX	Unlit flare	Methane	70.25
Reeves County, TX	Unlit flare	Methane	76.59
Reeves County, TX	Unlit flare	Methane	90.36
Reeves County, TX	Unlit flare	Methane	101.75

Reeves County, TX	Unlit flare	Methane	110.95
Reeves County, TX	Unlit flare	Methane	127.85
Reeves County, TX	Unlit flare	Methane	150.55

The prevalence of unlit flares begs the question of why operators are unable to ensure proper operation of their equipment. Flares are complex combustion devices that must be properly sized, operated, and maintained to ensure maximum combustion efficiency and minimal methane and VOC releases.

As the MAP report indicates (p.175), an important measure would be the use of auto igniters instead of intermittent or continuously burning flare pilots, as well as the installation of sensors to both determine if the pilot flame is extinguished or burning and to shut off the flow of gas when the pilot is extinguished.

In addition, it is critical that when gas is transported to the flare header, that the flare ignites for proper combustion. If the pilot lights do not remain lit, combustion will not occur—resulting in the flare functioning as a vent stack with minimal or even zero percent combustion (i.e., consistent with Earthworks' field observations). It is critical that the flare is properly sized, maintained, and operated for the optimal 98 percent combustion efficiency that can and should be expected of the technology.

We suggest that NMED and EMNRD look to the TCEQ for additional guidance in addressing the flaring and venting issue. TCEQ formed a Flare Task Force in 2009, based in large part on the agency's OGI program and the ability of OGI camera operators to generally assess the combustion efficiency of flares. Following technical meetings with refinery and petrochemical industry representatives and flare operators, TCEQ conducted a flare study that provided scientific evidence that improper flare operations and inattentive flare operators can negatively affect flare combustion efficiency.

The study led to the creation of a flare training course developed by TCEQ, the University of Texas, and industry and flare operator representatives. Both the TCEQ Flare Study and subsequent training modules can be used to train relevant technical staff on general flare operations and ensuring proper flare combustion.

We also suggest that NMED and EMNRD consider requiring third-party audits to determine flare combustion efficiency at oil and gas sites, which would in turn help operators identify mechanical problems (e.g., flare tip damage). A hand-held OGI camera assessment could be used by operators to check for general flare combustion efficiency, or a more exact determination could be made with additional instrumentation (e.g., Providence Photonics' Mantis Flare Monitor). Since many oil and natural gas companies are required to use OGI cameras to conduct Leak Detection and Repair (LDAR, discussed above), they could also add on field assessments of flares.

Such measures would be consistent with a comment in the MAP report (p. 194, section 6.14) that remote sensing be used to track decreases in methane emissions; it would be appropriate to add the use of OGI cameras to determine the prevalence of flare-related pollution plumes. This process could work in conjunction or independently of a related concept in the MAP report (p. 194, section 6.15), which states that operators should routinely inspect flares monthly to ensure proper operation.

8. Storage tanks (Section 8)

Because tanks are designed to store ostensibly usable and valuable products (e.g., condensate and oil) as well as products required by regulation to be properly handled (e.g., produced water), the assumption is that they will remain in a leak-free condition.

Federal and some state regulations are predicated on the assumption that tanks are "low emitters;" NSPS for storage tanks apply only to those that have emissions greater than or equal to 6 tons per year (tpy) of VOCs. Notably, Pennsylvania's draft oil and gas existing source rule sets a lower threshold for many sites (2.7 tpy), and because California's methane rules are based on leak concentrations, they apply to most storage tanks.

However, while multiple smaller tanks at a site could be exempt from regulation, taken together (i.e., as part of a single well site battery) they could emit significant volumes of pollution. For example, just five tanks emitting 5 tpy together would cross the threshold for qualifying as a "major" emissions source in states classified as in severe non-attainment for ozone.

As the MAP report indicates (p. 226 and 232), an open thief hatch results from operator neglect to close it after truck loading or measurement—a condition that could be remedied through proper training and inspections. The report also emphasizes (p. 235) that, "potential methane emission sources" include thief hatches, valves, and vents. However, the report neglects to mention that in order to contain emissions, not only do these sources need to be functioning properly, but the physical integrity of the storage tanks themselves must be maintained.

Metal corrosion and failure of welded seams are additional places for leaks to occur. In addition, tank lid seals must be inspected to ensure that weather and chemical exposure haven't compromised their physical integrity and in turn resulted in leaks. Additionally, pressure relief valves need to be properly maintained, including but not limited to maintaining pressure relief device set points.

In light of these factors, the volumes of methane emissions from tanks included in the MAP report are likely to be significantly underestimated. The report states (p.236) that these figures include, "flashing, breathing and working losses, but do not include emissions from tank thief hatches or other system/VRU malfunctions." Yet such conditions appear to be widespread in oil and gas fields, and require continual inspection and maintenance to remedy. In addition, the report acknowledges (p.240) that there are data gaps in measurement of emissions from tanks, particularly those without remote monitoring or controls.

As indicated above, storage tanks represent the largest proportion (40 percent) of the emission sources that Earthworks has observed with OGI in New Mexico. Earthworks' field observations of emissions from storage tanks indicate the prevalence of venting (potentially from relief valves or pipes) and thief hatches that have been left open. A few examples are included in the table below.

Location	Emissions Source	OGI video
Eddy County	Tanks	https://www.youtube.com/watch?v=2hLjr2aa4QU&feature=youtu.be
Eddy County	Tanks	https://www.youtube.com/watch?v=iyCGW5WPIpU&feature=youtu.be
Eddy County	Tanks	https://www.youtube.com/watch?v=nflrYEhqJpQ&feature=youtu.be

In addition, Earthworks has quantified emissions from tanks in New Mexico and the Permian Basin area of Texas using the QL320 from Providence Photonics; these measurements are summarized in the table below.

Location	Emissions Source	Proxy Parameter	Leak rate (lbs/hr)
San Juan County	Tanks	Methane	0.02
San Juan County	Tanks	Propane	0.18
San Juan County	Tanks	Methane	0.65
San Juan County	Tanks	Methane	1.06
San Juan County	Tanks	Methane	1.37
San Juan County	Tanks	Propane	1.64
San Juan County	Tanks	Propane	1.64
San Juan County	Tanks	Propane	1.64
San Juan County	Tanks	Methane	2.4
San Juan County	Tanks	Methane	2.5
Eddy County	Tanks	Methane	7.48
San Juan County	Tanks	Methane	8.6
Eddy County	Tanks	Methane	23.79
San Juan County	Tanks	Methane	24
Eddy County	Tanks	Methane	35.85
Eddy County	Tanks	Methane	40.92
Eddy County	Tanks	Methane	43.3
Eddy County	Tanks	Methane	52.44
Reeves County, TX	Tanks	Methane	15.01
Reeves County, TX	Tanks	Methane	24.49

9. Conclusions and the path forward

Earthworks supports the MAP's identification of cross-cutting issues outlined at the end of the draft report. In particular, NMED and EMNRD should consult with Tribes to ensure that any policies and regulations consider environmental justice aspects and do not disproportionately impact native communities.

We also support the call for industry to improve its monitoring and reporting mechanisms in order to narrow the gap between the limited volumes of emissions that are estimated and self-reported by operators, and the far greater emissions that are measured and reflect actual field conditions. Without an accurate picture of current and projected emission levels, there is a risk that state action—no matter how strong—will inevitably be too little, too late to reach New Mexico's climate goals.

Although the focus of the MAP and related processes is methane and climate change, reducing controlling emissions throughout the oil and gas development chain would also reduce health impacts by lowering levels of VOCs and hazardous air pollutants. We strongly support a focus on these co-benefits as a cross-cutting issue, and encourage NMED and EMNRD to consider requirements designed to protect health.

This approach would mirror recent progress in Colorado. The passage of SB-181 statutorily directs state agencies to prioritize public health and safety over oil and gas companies' private interests. This will require shifts in the regulatory system to ensure that it serves the public and responds to community input, including through a transparent complaint process.

State leaders and rulemakings by the Colorado Air Quality Control Commission are increasingly emphasizing public health and safety and the need to respond to impacted community concerns and recommendations. For example, beginning calendar year 2020, many "low emitting" well operators located within 1,000 feet of an occupied area will have to inspect components for leaks.

In light of the proposed rollbacks of federal NSPS emission control measures, the time for strong state action has never been greater. Given this, Earthworks applauds the climate goals put forth by Governor Lujan-Grisham, as well as NMED's recent measures to strengthen oil and gas enforcement.

Thank you again for the opportunity to participate in the MAP and to comment on the draft report. Earthworks looks forward to continued dialogue with NMED, EMNRD, and the stakeholders whose engagement will pave the way for strong, comprehensive, and effective methane control rules for New Mexico.

Sincerely,

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https://www.colorado.gov/pacific/sites/default/files/AP_Regulation-3-6-7-FactSheet.pdf

[2] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4. Tables 2 and 4, "Repair time periods."

[3] TransCanada. "Blowdown notification."
http://www.transcanada.com/docs/Our_Responsibility/Blowdown_Notification_Factsheet.pdf

[4] David Brown, Beth Weinberger, Celia Lewis and Heather Bonaparte, "Understanding exposure from natural gas drilling puts current air standards to the test," *Rev. Environ. Health* 2014, *available at* http://www.environmentalhealthproject.org/wp-content/uploads/2014/04/reveh-2014-0002-Brown-et-al.pdf

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[7] NMED, Excess Emissions Reporting, https://www.env.nm.gov/air-quality/excess-emissions-reporting/

[8] US EPA SPECIATE database, profiles based on David Allen and Vincent Torres, 2010 Flare Study, final report for the Texas Commission on Environmental Quality, https://www.tceq.texas.gov/assets/public/implementation/air/rules/Flare/2010flarestudy/2010-flare-study-final-report.pdf.