From: NMOAI, NMENV
Sent: Thursday, September 17, 2020 7:28 AM
To: Spillers, Robert, NMENV
Subject: Fw: Joint Comments on Ozone Precursor Proposal
Attachments: EDF Comments NMED rule.pdf; EDF NMED EXHIBIT 1.pdf; EDF NMED EXHIBIT 2.pdf

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From: Jon Goldstein <jgoldstein@edf.org>
Sent: Wednesday, September 16, 2020 3:21 PM
To: NMOAI, NMENV; Kuehn, Elizabeth, NMENV
Cc: Ely, Sandra, NMENV; Emily Wolf; Calman, Judy; Michael Casaus; elizabeth paranhos (elizabethparanhos@delonelaw.com)
Subject: [EXT] Joint Comments on Ozone Precursor Proposal

Ms. Bisbey-Kuehn,

Please find attached joint comments and two exhibits submitted on behalf of EDF, The Wilderness Society, National Parks Conservation Association and Audubon New Mexico regarding the state's draft ozone precursor rules.

Please let us know if you have any questions and we look forward to continued engagement as this proposal moves forward.

Jon

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ENVIRONMENTAL DEFENSE FUND, THE WILDERNESS SOCIETY, AUDUBON NEW MEXICO, NATIONAL PARKS CONSERVATION ASSOCIATION

I. Introduction

Environmental Defense Fund (EDF), The Wilderness Society (TWS), National Audubon Society and the National Parks Conservation Association greatly appreciates the opportunity to submit comments on New Mexico Environment Department's (NMED) Proposed Rules on Oil and Natural Gas Regulation for Ozone Precursors.

EDF is a national membership organization with more than 2.5 million members residing throughout the United States and more than 18,000 residing in the state of New Mexico, many of whom are deeply concerned about the pollution emitted from oil and natural gas sources. EDF brings a strong commitment to sound science, collaborative efforts with industry partners, and market-based solutions to our most pressing environmental and public health challenges.

The Wilderness Society (TWS) is a non-profit organization dedicated to uniting people to protect America's wild places. TWS is one of America's leading public lands conservation organizations. Since 1935, TWS has been dedicated to protecting America's wild places for current and future generations, which requires eliminating climate-changing emissions. We are committed to smart and sensible regulation and work to ensure that public resources are used effectively, efficiently, and responsibly. TWS has offices throughout the country, including an office Albuquerque, New Mexico. TWS has several thousand members in New Mexico and over one million members and supporters nationwide.

Audubon New Mexico is the statewide office of the National Audubon Society, a national nonprofit conservation organization dedicated to protecting birds and the places they need, now and in the future, throughout the Americas, using science, advocacy, education, and on-the-ground conservation. Founded in 1905, Audubon has approximately 1.7 million members nationwide, including more than 13,000 in New Mexico. Its state/regional offices, nature centers, chapters, and partners give Audubon an unparalleled wingspan that reaches millions of people each year to inform, inspire, and unite diverse communities in conservation action. Audubon has been engaging in research, education, advocacy and restoration activities with regards to oil and gas issues for many years and will continue to do so.

Formed in 1919, the National Parks Conservation Association's mission is to protect and enhance America's National Park System now and for future generations; our nearly 1.4 million members and supporters nationwide continue to fulfill this mission by working to connect our national parks with their surrounding landscapes.

In New Mexico, EDF has been active in NMED rulemakings and participated as a member of the Methane Advisory Panel (MAP), which led to the creation of the MAP White Paper.

We commend NMED for the steps it has taken to craft pragmatic and effective draft rules for the oil and gas industry. Many of the proposed requirements represent leading, cost effective measures that have the potential to significantly reduce ozone precursor emissions and achieve significant climate and health co-benefits. However, as currently drafted the rules contain two exemptions that eviscerate the potential benefits from the rules. These two exemptions are for (1) stripper wells, which are defined as wells producing less than 10 barrels of oil per day or less than 60 thousand standard cubic feet of natural gas per day, and (2) well sites with a potential to emit less than 15 tons of volatile organic compounds per year. As drafted, wells that satisfy *either* criterion would be exempt from the control requirements in the rule. NMED must remove these overly expansive exemptions in order to achieve the Governor's goal of implementing leading measures to reduce pollution from oil and gas sources. Our comments below focus on the impact of these two exemptions and demonstrate that the proposed control strategies for individual sources are cost effective absent the exemptions. We also support the comments submitted by Clean Air Task Force and the Sierra Club to include pneumatic controllers in leak detection and repair inspections, expand requirements for zero bleed controllers and require monthly inspections at larger well production facilities.

II. NMED Must Promulgate A Rule That Ensures Attainment of The Federal Health-Based Guidelines for Ozone

NMED has a duty to promulgate regulations that control ozone precursor emissions (volatile organic compounds and oxides of nitrogen) to provide for attainment and maintenance of the national ambient air quality standard (NAAQS) for ozone whenever "the environmental improvement board or a local board determines that emissions from sources within its jurisdiction cause or contribute to ozone concentrations in excess of ninety-five percent of a national ambient air quality standard for ozone."[1] Per NMED, Chaves, Eddy, Lea, Rio Arriba, Sandoval and San Juan counties have monitored ozone concentrations in excess of ninety-five percent of the ozone NAAQS.[2]

NMED must, accordingly, promulgate a rule that controls VOC emissions from oil and gas sources in these six counties in order to "provide for attainment and maintenance" of the ozone NAAQS. NMED cannot rely on rules promulgated by other agencies, including the Oil Conservation Commission, to fulfill NMED's duty to control VOC emissions from oil and gas sources in these six counties.[3] Moreover, the Oil Conservation Division's proposed rules simply will not lead to adequate reductions (i.e., potentially allowing a 2% leak rate would not be sufficient and would be 10 times worse than what the leading oil and gas producers have committed to as a part of the Oil and Gas Climate Initiative). Thus, NMED's proposed control requirements must "control ozone precursor emissions (volatile organic compounds and oxides of nitrogen) to provide for attainment and maintenance of the national ambient air quality standard (NAAQS) for ozone" on their own merit.[4] Because of the current proposed stripper well and low TPY facility exemptions, the proposed rule fails to do so.

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[1] N.M.S A. § 74-2-5.3.
[2] NMED, Rule Preamble, Title 20, Ch. 2, Pt. 50, https://www.env.nm.gov/new-mexico-methane-strategy/wp-content/uploads/sites/15/2020/07/Draft-Ozone-Precursor-Rule-for-Oil-and-Natural-Gas-Sector-Version-Date-7.20.20.pdf
[3] N.M.S A. § 74-2-5.3.
[4] *Id*.

III. Low-Producing Wells are Responsible for Significant Emissions

Low producing, marginal wells are the most abundant type of oil and gas well in the United States, and a surprising number of them are venting all of or more than their reported produced gas to the atmosphere.[5] This makes marginal wells a disproportionate volatile organic compound (VOC) and methane source compared to their energy production, and underscores the need for robust control requirements.

Several recent studies, including one of well sites in the Permian Basin, demonstrate that production is not a proxy for emissions; rather, low-producing wells emit a significant percentage of their gas production or are otherwise significant emitters.

A recent study involving site-level measurements of over 70 Permian Basin well pads found that methane emissions are higher than in most other measured basins. This study also found no relationship between emissions and production. Per the study, wells that would qualify for the proposed stripper well exemption (those with production below 10 barrels of oil equivalent per day) had similar emissions as non-marginal wells.[6]

Another 2018 study used site-level methane emissions data from over 1000 natural gas production sites in eight basins, including 92 new site-level methane measurements in the Uinta, northeastern Marcellus, and Denver-Julesburg basins, to investigate methane emissions characteristics and develop a new national methane emission estimate for the natural gas production sector. The study looked at natural gas production sites and categorized them as low (sites producing <100 Mcfd), intermediate (100 to 1000 Mcfd), and high (>1000 Mcfd). The study found that low natural gas production sites "emit a larger fraction of their CH_4 production" than the intermediate and high production sites.[7]

A 2020 study involving direct measurements of methane and VOC emissions from marginal oil and gas wells in the Appalachian Basin of southeastern Ohio, all producing < 1 BOE d, found similar results. The study found that marginal wells are a disproportionate source of methane and VOC emissions relative to oil and gas production. The study estimated that oil and gas wells in this lowest production category emit approximately 11% of total annual methane from oil and gas production in the EPA greenhouse gas inventory, although they produce about 0.2% of oil and 0.4% of gas in the US per year.[8]

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[5] Jacob A. Deighton, *et. al*. Measurements show that marginal wells are a disproportionate source of methane relative to production (Aug. 2020).

[6] Anna Robertson et al. New Mexico Permian Basin Measured Well Pad Methane Emissions are a Factor of 5 – 9 Times Higher Than US EPA Estimates. Environmental Science & Technology (accepted). Measurements were taken in 2018.

[7] Omara, M. *et al*, Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, Environ. Sci. Technol. 2018, 52, 12915−12925. Low production sites accounted for only 9.6% of total natural gas production.

[8] Deighton, J.A., et. al. Measurements show that marginal wells are a disproportionate source of methane relative to production (Aug. 2020).

These studies demonstrate that controlling low producing wells, such as those currently exempt by the stripper well and low PTE facilities exemptions, is essential to curbing emissions from oil and gas facilities.

IV. NMED Must Remove Exemptions for the Low PTE Facilities and Stripper Wells

EDF conducted an analysis of the impact of the two exemptions for well sites with a PTE of less than 15 TPY of VOCs ("low PTE facilities") and stripper wells on both the number of facilities that would be subject to the rule's control requirements and the tons of VOCs and methane that would be exempt. Per this analysis, the exemptions carve out 95 percent of wellheads and production sites in the six counties subject to the proposed NMED rule and a significant percent of emissions. Specifically, the low PTE facilities exemption carves out 70% of methane emissions and 64% of VOC emissions, while the stripper well exemption would result in 26% of methane emissions and 27% of VOC emissions being left unabated.

EDF analyzed the impact of the low PTE facilities exemption by examining the number of facilities in the NMED permit/NOI database and calculating the number of facilities that fall below the proposed PTE threshold. NMED requires facilities with regulated emissions above 25 tons per year ("tpy") to have an air permit. Oil and gas facilities are required to submit a Notice of Intent (NOI) if they have regulated air contaminant emissions above 10 tpy. The NMED methane map includes both NOIs and permits.[9] Looking at NMED Permits and NOIs shows 2,465 Wellheads and Production Sites with Permits and NOIs. The permit and NOI database includes PTE for VOC emissions; using these data shows that 2,398 Wellheads and Production Sites have a VOC PTE above 15 tpy VOC. EDF determined the total number of oil and gas facilities in New Mexico to be roughly 43,100, using data from DrillingInfo. Therefore, roughly 95% of wellheads and production sites in NM will be below the 15 tpy VOC threshold and will be exempted from the rule.

To calculate the impact of the stripper well exemption on the number of covered facilities, EDF pulled well data from Enverus/DrillingInfo. Wells were clustered into well sites based on a 50 mile radius. Average oil production (bbl/day) and average gas production (Mcf/day) were calculated on a per well basis. If the average oil production was less than 10 bbl/day/well or the average gas production was less than 60 Mcf/day/well, a well site was determined to be a stripper well.

Breaking out the exemptions by basins in New Mexico demonstrates the extent of the effect.

Combined Exemptions		
Basin	**Number of sites exempted**	**Percentage of sites exempted in that basin**
San Juan	16870	96%
Permian Basin	25075	97.4%
Raton	821	100.0%
Stripper Well Exemption Only		

[9] https://gis.web.env.nm.gov/oem/?map=methane

Basin	Number of sites exempted	Percentage of sites exempted in that basin
San Juan	12125	69.0%
Permian Basin	19454	75.6%
Raton	493	60.0%
<15 PTE Exemption Only		
Basin	**Number of sites exempted**	**Percentage of sites exempted in that basin**
San Juan	16673	94.9%
Permian Basin	25043	97.3%
Raton	821	100.0%

1. Exempting Low PTE Facilities Leaves Significant Emissions Reductions on the Table

The proposed exemptions not only carve out the majority of wellheads and production sites in the state from proposed control requirements, they also leave unabated the majority of VOC and methane emissions from oil and gas facilities. In order to calculate the percent of emissions exempted, EDF relied on its estimate of site-level emissions in our Synthesis model to estimate the actual VOC and CH_4 emissions associated with the exempt facilities. The Synthesis model estimates site-level methane and VOC emissions for all well sites in the state.

The 15 TPY exemption would leave on the table 654,109 MT of methane (nearly 70% of total statewide methane emissions from oil and gas facilities) and 215,621 short tons of VOC (64% of total statewide VOC emissions from oil and gas facilities).

Exemption	Percent of total well sites exempted	Methane emissions exempted (MT)	Percent of methane emissions exempted	VOC emissions exempted (short tons)	Percent of VOC emissions exempted
PTE < 15 tpy VOC	96.5%	654,109	69.6%	215,621	64.1%

2. Exempting Stripper Wells Leaves Significant Emissions Reductions on the Table

EDF analysis demonstrates that the stripper well exemption carves out 244,866 MT of methane emissions and 89,304 short tons of VOC emissions.

Exemption	Percent of total well sites exempted	Methane emissions exempted (MT)	Percent of methane emissions exempted	VOC emissions exempted (short tons)	Percent of VOC emissions exempted
Stripper well	72.7%	244,866	26.1%	89,304	26.5%

NMED must remove the stripper well and low PTE facilities exemption in order to promulgate an effective rule that will reduce ozone precursor emissions in the six counties that are bumping up against the federal health-based standards for ozone.

3. Removing the Exemptions Will Improve Protections for New Mexico's Most Vulnerable Populations

If the exemptions are not eliminated from the proposed rule, New Mexico's most vulnerable communities will bear the brunt of these avoidable emissions. In the San Juan Basin, 94% of wells would not be inspected if the exemptions remain in the rule. Notably, 54,000 disadvantaged community members live within a half mile of these wells. In the Permian Basin, 87% of wells would not be inspected if the exemptions remain in the rule. In this Basin, 28,000 members of vulnerable, disadvantaged communities live within one half mile of these wells. The chart below shows the percentage of children under five, Latinos, Native Americans and African Americans living in close proximity to wells that would be exempted from the requirements in the proposed rules.

San Juan Basin				
• 94% of wells would not be checked • 54,000 vulnerable people live within one half mile of these wells				
County	**Kids under 5**	**Latinos**	**Native Americans**	**African Americans**
Rio Arriba	7%	1%	27%	12%
San Juan	72%	91%	45%	82%
Permian Basin				
• 87% of wells would not be checked • 28,000 vulnerable people live within one half mile of these wells				
County	**Kids under 5**	**Latinos**	**Native Americans**	**African Americans**
Eddy	38%	39%	40%	30%
Lea	33%	35%	27%	16%

V. Controlling Sources at Exempt Sites Is Cost Effective

1. Findings

EDF contracted with Synapse Energy Economics, Inc., to model the estimated VOC and methane reductions, compliance costs and other benefits associated with the recommended controls for sources in the production segment and evaluate the cost-effectiveness of the proposed rules without any exemptions (EDF Exhibit 1). Synapse's modeling demonstrates the proposed rules are cost-effective when considering four separate categories of benefits without including the proposed exemptions.[10] Namely, the report concluded:

[10] Synapse, Cost-Effectiveness of Proposed New Mexico Environment Department Oil and Gas Emissions Reduction Rules, Prepared for Environmental Defense Fund, p. 12 (Sept. 9, 2020), Exhibit 1, https://www.synapse-energy.com/project/benefit-cost-analysis-proposed-voc-emissions-rules-new-mexico.

- The proposed controls, absent the exemptions, would achieve a 3 million tonnes reduction in VOCs from 2020-2030 and can be achieved for a cost of $575 por tonne of VOC reduced.[11]
- The proposed controls, absent the exemptions, could achieve just over $126 million in human health benefits in New Mexico due to reduced VOC emissions. Notably, this is a conservative estimate as the health benefits do not include those associated with reductions in ground-level ozone that are likely to accompany reduced VOC emissions.
- The proposed controls, absent the exemptions, could result in avoided nonattainment costs of $1.2 billion over a six year period at a 3 percent discount rate.
- The proposed controls, absent the exemptions, could result in $730 million of captured gas between 2020 and 2030. This equals $99 million in royalties to the state of New Mexico.
- The proposed controls, absent the exemptions, could generate $12.3 billion in global climate benefits between 2020 and 2030 due to reductions in methane emissions as a co-benefit.[12]

2. Methodology

In order to determine the cost-effectiveness of the comprehensive controls, Synapse quantified four categories of benefits from the proposed set of regulations:

(1) ***The value of captured gas that would otherwise be vented or flared***. One effect of the proposed regulations without the exemptions would be shifting emissions that would have been vented into the captured category. Captured gas has economic value, so the increased capture results in economic benefit attributable to the regulation.

(2) ***The human health benefits of reduced air pollution***. The Synapse Report focused solely on health benefits associated with reduced particulates from reduced VOC emissions. Reduced VOC and particulate emissions lead to lower human mortality, illnesses, and associated detriment to the economy.

(3) ***The reduced cost of compliance with EPA requirements applicable to ozone nonattainment rules.*** Here, the report evaluated regulatory actions to limit VOC emissions from the oil and gas industry, and the effect these limits have in meeting EPA's National Ambient Air Quality Standards (NAAQS) for ground-level ozone. When an area falls out of attainment with the NAAQS, measures must be taken that impede economic development by requiring greater investment in pollution controls for expanded or new facilities.

(4) ***The global social benefit from the reduction in greenhouse gas emissions***. Synapse quantified the impact that reducing methane emissions as a co-benefit of direct VOC reductions has on mitigating climate change, including reducing damages associated with the spread of disease, coastal destruction, and decreased food security.

[11] *Id*. at 13.
[12] *Id*. at 16.

Synapse compared the benefits and costs of the proposed control requirements, absent the exemptions, to yield a benefit-cost ratio (BCR), with the discounted benefits in the numerator and the discounted costs in the denominator. A BCR above 1 indicates that the program is cost-effective because the total lifetime benefits outweigh the total lifetime costs of the regulation. A BCR below 1 indicates that the program is not cost-effective because the costs are higher than the benefits. All costs and benefits in Synapse's analysis were discounted at a rate of 3 percent and in constant 2019 dollars. Synapse calculated three distinct BCRs, with each including different benefits in the numerator of the ratio:

1. **New Mexico BCR**: This ratio includes the benefits of captured gas, avoided health impacts for New Mexico, and the value of avoided NAAQS nonattainment. Although the NAAQS nonattainment benefits have a high degree of uncertainty, Synapse considers this ratio to be conservative because the local health benefits associated with reduced ground-level ozone are not included.

2. **National BCR**: In addition to the benefits of the New Mexico BCR, this ratio also includes the avoided health impacts for the rest of the contiguous United States. This ratio quantifies the benefits of the proposed rules to the entire country.

3. **Global BCR**: In addition to the benefits of the National BCR, this ratio also includes the greenhouse gas benefit of avoided methane emissions. This benefit is only included in the Global BCR because the value will accrue to the benefit of people around the world, rather than just to people in this country.

The proposed oil and gas emission reduction rules, without the exemptions, were found to be cost-effective across all three Benefit Cost Ratios. The Primary New Mexico BCR, which is considered the most conservative ratio, is 1.32 over the eleven-year study period. If negative health impacts from ground-level ozone were quantified, this ratio would be higher. Based on this perspective, for every $1 million dollars of costs associated with the proposed rules, New Mexico's residents and firms are expected to benefit by at least $1.32 million dollars from captured gas revenue, reduced health-related costs and reduced NAAQS compliance costs. This translates to a net benefit of $0.49 per mcf of recovered methane.[13]

The National BCR, which also includes the human health benefits to the rest of the contiguous United States from particulates associated with reduced VOC emissions, is 1.85 over the eleven-year study period. In this case, for every $1 million dollars of costs associated with the comprehensive controls, the United States is expected to benefit by at least $1.85 million dollars from captured gas revenue, reduced health-related costs, and reduced ozone regulation compliance costs. This translates to a net benefit of $1.30 per mcf of recovered methane.[14]

Finally, the Global BCR—which includes all benefits from the National BCR, plus the avoided social cost of methane—is 22.95 over the eleven-year study period. For every $1 million dollars of costs associated with the proposed rules, Synapse calculated a global benefit of at least $22.95 million dollars of from captured gas revenue, reduced health-related costs, reduced ozone

[13] *Id.* at 12.
[14] *Id.*

regulation compliance costs, and mitigation of climate change. This translates to a net benefit of $33.36 per mcf of recovered methane.[15]

In conclusion, Synapse determined that the proposed rules are cost-effective when evaluating the potential health, economic and climate benefits that could be achieved if *all* oil and gas facilities in the six counties subject to the rule were required to comply with the proposed NMED rules.

VI. NMED Must Strengthen the Alternative Leak Detection Method Provision

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

The current rule allows operators to use a Method 21 leak detector, optical gas imaging camera, or alternative leak monitoring plan approved by the NMED. We recommend the rule specify that an alternative leak detection device or method must achieve equivalent emission reductions as allowed devices or methods. Specifically, we suggest adding the following definition to the rule:

> "Alternative Equipment Leak Monitoring Plan" means a monitoring plan approved by the Department that achieves equivalent emission reductions as an Approved Instrument Monitoring Method.

With this definition, we recommend also revising the current definition of "Approved Instrument Monitoring Method" to read as follows:

> "Approved Instrument Monitoring Method" means an infra-red camera or U.S. EPA Method 21~~, or other instrument-based monitoring method or program approved by the Department in advance and in accordance with 20.2.50 NMAC~~"

In addition, NMED should issue guidance materials describing the process for applying for use of an alternative device or method and the information required to demonstrate equivalent emission reductions.

The leak detection technology landscape is highly dynamic, with innovation happening in real time, for example through ARPA-E's MONITOR project and EDFs Methane Detectors Challenge project in partnership with seven large producers and other stakeholders.[16] It is crucial for state rules to create space for innovative technologies, which may be able to deliver improved environmental performance at reduced cost. In 2015, Colorado adopted a rule and detailed guidance documents setting forth the specific elements an alternative leak detection technology must demonstrate, and the process by which such an alternative technology is reviewed and

[15] *Id*.
[16] EDF, Pathways for Alternative Compliance, A Framework to Advance Innovation, Environmental Protection, and Prosperity (April 2019), Exhibit 2.

approved.[17] We urge NMED to adopt similar criteria, accompanied by clear and transparent instructions, governing the necessary elements of an application for an alternative technology and the approval process. Such an approach will help catalyze a race to the top in technology, control costs for the regulated community and boost environmental outcomes

VII. Certification of Control Devices

We further suggest NMED add a requirement that operators certify that their control devices (whether they be VRUs, flares or combustors) are adequately sized and operate in accord with the design in order to capture, convey and control emissions. Equipment must be designed to handle the pressure of liquids when transferred from separators to tanks. If the tank vapor system is not adequately sized to handle the peak surge of flash emissions that occur when pressurized liquids dump to the atmospheric storage tanks, then flash emissions do not make it to the control devices. Rather, access points on tanks designed to only open during emergencies or maintenance, such as thief hatches and pressure relief valves, open, releasing uncontrolled flash emissions to the atmosphere.

Recent inspections by EPA and Colorado have revealed that inadequately designed and operated storage tank vapor control systems can result in very significant emissions. In inspections of 99 storage tank facilities in Colorado's Denver-Julesburg basin in 2012, the Colorado Air Pollution Control Division and EPA found that emissions were not directed to their intended control devices at 60% of the facilities. These inspections formed the basis for a $73 million dollar settlement between Noble Energy, the U.S. EPA and the state of Colorado that covered over 3,400 tank batteries where regulations "relating to installation, operation, maintenance, design, and sizing of vapor control systems" were violated, resulting in excessive emissions.[18] U.S. EPA notes that "[I]mproperly or inadequately designed, sized, operated, or maintained vapor control systems can lead to uncontrolled emissions of [hydrocarbons]."[19]

In late 2016, EPA reached a consent decree settlement with Slawson Exploration, Inc., over violations at Slawson's storage tanks at approximately 170 facilities in the Bakken formation in North Dakota. Similar to the Noble settlement, the Slawson settlement "resolves provisions implicated by claims that Slawson failed to adequately design, operate, and maintain vapor control systems on its storage tanks at oil and natural gas well pads, resulting in emissions of [hydrocarbons]."[20]

Observations show that this problem is not limited to these two companies. A 2016 study reported results from helicopter surveys of thousands of wellpads. Almost 500 sites had emissions high enough to be detectable with the helicopter-mounted camera; at over 90% of these sites, the emissions were from a tank/tank source. In the Bakken, 14% of sites have detectable emissions,[21] even though many of these tanks are controlled. The authors of the helicopter survey paper report

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[17] CO Reg. 7, § XII.8.a; CDPHE, Procedures on AIMM Process, AQCC Regulation No. 7, p. 3 (July 6, 2015) (accessible at https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf).
[18] Noble Energy, Inc. Settlement (April 22, 2015), https://www.epa.gov/enforcement/noble-energy-inc-settlement
[19] *Id*.
[20] EPA, https://www.epa.gov/enforcement/slawson-exploration-company-inc-clean-air-act-settlement.
[21] Lyon, D.R., *et al*., (2016) "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environ. Sci. Technol*. **50**, 4877. http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705

that “tank emission control systems commonly underperform.”[22]

Recently implemented rules by EPA[23] and Colorado address this problem. Colorado’s 2014 oil and gas rules were the first to require operators to inspect access points on storage tanks, such as pressure relief devices and thief hatches on tanks, monthly, quarterly or annually, depending on the amount of production at the facility.[24] In addition, operators must develop a Storage Tank Emission Management System plan. The purpose of this plan is to ensure that the storage tank facility is designed and operated properly to ensure that tanks must operate without venting from access points during normal operation. Per the plan requirements operators must:

- Monitor for venting using approved instrument monitoring methods and sensory detection methods;
- Document any training undertaken by operators conducting the monitoring;
- Analyze the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;
- Identify the procedures to be employed to evaluate ongoing capture performance;
- Have in place a procedure to update the storage tank system if capture performance is found inadequate;
- Certify that they have complied with the requirement to evaluate the adequacy of their storage tank system.[25]

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

> It is the EPA’s experience, through site inspections and interaction with the states, that closed vent systems and control devices for storage vessels and other emission sources often suffer from improper design or inadequate capacity that results in emissions not reaching the control device and/or the control device being overwhelmed by the volume of emissions.[26]

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

A. Flares

[22] Lyon, D.R., *et al.*, (2016), 4877.
[23] 42 C.F.R. § 0000a.
[24] 5 C.C.R 1001-9, Part D, § II.C.2.b.(ii)(I).
[25] 5 CCR 1001-9 § XIX.N., Statement of Basis and Purpose (Feb. 23, 2014).
[26] 81 Fed. Reg. 35824, 35871 (June 3, 2016).

NMED should require a 98% destruction removal efficiency of all flares and combusters used to control emissions. A 98% destruction and removal efficiency or greater is common in state requirements. Colorado requires that combustion devices used to control hydrocarbons at tanks, glycol dehydrators, and gas "coming off a separator, [or] produced during normal operation" must have a design destruction efficiency of at least 98% for hydrocarbons.[27] Wyoming similarly requires that combustion devices used to control emissions from tanks, separation vessels, glycol dehydrators, and pneumatic pumps meet a 98% control requirement.[28] North Dakota similarly requires operators use control devices that achieve at least a 98% destruction removal efficiency for VOCs to control emissions from glycol dehydrators and tanks with the potential to emit greater than 20 tons of VOCs annually at production facilities in the Bakken Pool.[29]

We urge NMED to require flares and combusters to operate with a destruction efficiency of at least 98%, which can typically achieve a destruction and removal efficiency in excess of 99.5 percent.[30] Several studies demonstrate flares routinely malfunction, releasing significant tons of climate altering pollution into the atmosphere. EDF researchers conducted three separate helicopter surveys of hundreds of flares in the Permian Basis in February through early July in 2020. Researchers found that 11% of flares surveyed had combustion issues, including 5% that were unlit and venting gas.[31] In one of the helicopter surveys it was found that 25% of unlit or partially lit flares identified during a prior survey remained problematic at subsequent surveys. These findings indicate that malfunctioning flares are a recurring and persistent problem.[32] This underscores the need for provisions that require the use of efficient flares and auto-igniters that ensure flares stay lit, as well as frequent inspections to detect malfunctioning flares.

B. Reporting requirements

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

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[27] 5 CCR 1001-9, Part D, §§ I.D.3.a. (Storage Tank Control Strategy), II.C.1. (Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants); II.D. Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8; Wyo. Dep't of Envtl. Quality, Oil and Gas Production Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised Dec. 2018), available at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf .

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

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

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

[31] EDF, With Initial Data Showing Permian Flaring on the Rise Again, New Survey Finds Malfunctioning or Unlit Venting Unburned Methane into the Air 1 in 10 Flares, July 22, 2020, **https://www.edf.org/media/initial-data-showing-permian-flaring-rise-again-new-survey-finds-1-10-flares-malfunctioning**

[32] *Id*.

In Colorado, companies must submit semi-annual reports wherein a "responsible official" certifies the accuracy of the data.[33] The certification attests to the truth, accuracy and completeness of the statements and information in the report and certifies the data is based on information and belief formed after reasonable inquiry. The Clean Air Act also utilizes the "responsible official" concept. For example, any person required to have a permit must "submit to the permitting authority a compliance plan and an application for a permit signed by a responsible official, who shall certify the accuracy of the information submitted."[34] The Clean Air Act also provides that "[a]ny report required to be submitted by a permit issued to a corporation under this subchapter shall be signed by a responsible corporate official, who shall certify its accuracy."[35]

VIII. Conclusion

NMED must promulgate a rule that controls ozone precursor emissions "to provide for attainment and maintenance of the [ozone NAAQS] standard."[36] The current rule fails to meet this statutory requirement as the vast majority of production sites and VOC emissions associated with those sites are exempt. NMED must fix this fatal flaw in its rule. Doing so would ensure

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

[34] 42 U.S. Code § 7661b(c). Federal regulations (40 C.F.R. 70.2) define "responsible official" as one of the following: (1) For a corporation: a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either: (i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or (ii) The delegation of authority to such representatives is approved in advance by the permitting authority; (2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively; (3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of EPA); or (4) For affected sources: (i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and (ii) The designated representative for any other purposes under part 70.

[35] 42 U.S. Code § 7661c(c).

[36] N.M.S.A. 1978, § 74-2-5.3

NMED fulfills the Governor's commitment to promulgate a leading rule to curb emissions from oil and gas sources as many of the proposed control strategies are strong absent the exemptions.

Thank you for consideration of these comments. We look forward to working with NMED to strengthen and finalize the proposed rules.

Sincerely,

Jon Goldstein
Director, Regulatory & Legislative Affairs
EDF

Elizabeth Paranhos
Attorney Consultant, EDF

Michael Casaus
State Director
The Wilderness Society

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National Parks Conservation Association

Cost-Effectiveness of Proposed New Mexico Environment Department Oil and Gas Emissions Reduction Rules

Impacts and Co-Benefits of Reduced Volatile Organic Compound Emissions from the Oil and Gas Industry

Prepared for Environmental Defense Fund

September 15, 2020

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CONTENTS

1. INTRODUCTION

The New Mexico Environment Department recently announced proposed oil and gas emissions reduction rules (hereafter called "proposed rules") that would require a set of actions to reduce pollutant emissions of volatile organic compounds (VOC) from the oil and gas industry in New Mexico. These rules also reduce methane emissions as a co-benefit; however, reducing methane flaring is not included in these proposed rules.[1] Methane emissions can occur in the production, processing, or delivery phases of the oil and gas supply chain. The total cumulative methane emissions reduction expected to be realized by the proposed rules over a 10-year period (2020–2030) is 8.6 million tonnes. Similarly, the total cumulative VOC emissions reduction required by these controls is approximately 3 million tonnes. Though these proposed rules set specific requirements or performance standards intended to achieve emissions reductions, they do not always specify a mitigation technology. Rather, by setting standards the proposed rules allow for flexibility and encourage innovation in pollution control technologies. [2]

Though reducing pollutant emissions has many benefits for the people of New Mexico, there are also costs to implementing the recommended standards. On behalf of Environmental Defense Fund (EDF), Synapse Energy Economics, Inc. (Synapse) performed a benefit-cost assessment of the proposed rules for New Mexico. In developing the analysis presented in this report, Synapse relied upon calculations conducted by EDF and Spherical Analytics for emission reductions that would result from implementation of the recommended standards (see APPENDIX C. Emissions Reduction Data by County). The sections below present Synapse's approach and results.

The Environment Department's proposed emissions rules currently exempt two classes of sites from the regulation: (1) sites with stripper wells, which over the course of a year produce less than 10 barrels of oil per day, less than 60,000 standard cubic feet of gas per day, or less than 10 barrels of oil equivalent of both oil and gas per day, and (2) sites with wells having a potential to emit less than 15 tons of VOCs per year. According to EDF's analysis, 95 percent of producing wells in New Mexico fall into one of these two categories.[3] Therefore, this analysis evaluates the cost-effectiveness of the proposed rules without

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[1] The accompanying proposed emissions rules drafted by the Oil Conservation Division include reduced methane flaring. This report does not analyze the additional impact of those proposed rules.

[2] New Mexico Environment Department (NMED). Draft Ozone Precursor Rule for Oil and Natural Gas Sector. July 20, 2020. See https://www.env.nm.gov/new-mexico-methane-strategy/wp-content/uploads/sites/15/2020/07/Draft-Ozone-Precursor-Rule-for-Oil-and-Natural-Gas-Sector-Version-Date-7.20.20.pdf.

[3] Oil and gas facilities are required to have Minor permits if they have any regulated air contaminant emissions above 25 tons per year. EDF downloaded all oil and gas production facilities permits from this NMED website: https://air.net.env.nm.gov/rsmt/. NMED is correct in claiming that almost all their permits are above the 15 tons per year threshold; however, less than 1% of oil and gas facilities in the state have a permit. Since the threshold for permits (25 tons per year) is higher than the 15 tons per year potential to emit exemption threshold, EDF also analyzed Notice of Intents (NOI). Oil and gas facilities are required to submit a NOIs if they have any regulated air contaminant emissions above 10 tons per

any exemptions, to determine whether removing the exemptions would result in rules that would have a negative impact on New Mexico.

2. COST-EFFECTIVENESS EVALUATION

In order to determine the cost-effectiveness of the proposed rules without exemptions, Synapse calculated the benefits of reducing methane and VOC emissions and the costs of reducing those emissions. Together, the benefits and costs come together to yield a benefit-cost ratio (BCR). In this section, we discuss the benefit types evaluated in this study, followed by the costs associated with the regulation. In the following section we present a description of the three BCRs used to evaluate the proposed rules for New Mexico.

2.1. Benefits Estimation

Synapse quantified four categories of benefits from the proposed set of regulations: (1) the human health benefits of reduced air pollution; (2) the reduced cost of compliance with federal ozone regulations; (3) the value of captured gas that would otherwise be vented or flared; and (4) the global social benefit from the reduction in greenhouse gas emissions. We discuss the methodology for each category below.

Human Health Benefits

Exposure to air pollution from fossil-fuel production and combustion can exacerbate human respiratory disease, cause heart attacks, and lead to premature death. Illnesses from air pollution can also result in other costs to society, such as medical costs and lost wages to treat and recover from the illness. Oil and gas operations are associated with forms of air pollution during the fuel extraction process, including methane gas flared into the atmosphere (i.e., burned and converted into carbon dioxide and other compounds). Furthermore, VOCs released during oil and gas production can react with existing nitrogen oxides (NO_X) in the atmosphere to form ground-level ozone, which can lead to respiratory diseases.[4]

Synapse utilized U.S. Environmental Protection Agency's (EPA) CO-Benefits Risk Assessment (COBRA) tool to quantify a portion of the human health benefits of reduced emissions associated with the proposed rules.[5] COBRA estimates both health and health-related economic impacts of changes in

year. The NMED methane map (https://gis.web.env.nm.gov/oem/?map=methane) includes NOIs along with permits. EDF's analysis indicates about 95% of production facilities in the state will be exempt under the NMED's initial proposed draft rule.

[4] U.S. EPA, Health Effects of Ozone Pollution. Available at: https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution. Accessed 2019.

[5] U.S. EPA, CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool. Available at: https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool.

pollutant emissions for a given geography. COBRA quantifies human health impacts from reductions of the following air pollutants: $PM_{2.5}$, sulfur dioxide (SO_2), NO_x, ammonia (NH_3), and VOCs. COBRA does not quantify the impact of direct methane emissions into the atmosphere, but it can quantify the impacts of its combustion (flaring) products (SO_2 and NO_x).

Because the proposed rules do not require a reduction in emissions from methane flaring, we focused solely on health benefits associated with reduced particulates from reduced VOC emissions. The value of direct health impacts of reduced ground-level ozone (smog) was excluded due to the complexity of the process by which ozone is created in the atmosphere. Nonetheless, as the following section on ozone air quality regulations indicates, the proposed rules would have a substantial positive effect on human health from the reduction in ground-level ozone exposure. Because $PM_{2.5}$ and ozone were excluded from the health impacts analysis, we consider our calculation of the benefits associated with the proposed rules to be conservative. Actual benefits are likely to be greater than estimated in this report.

Avoided NAAQS Nonattainment Costs

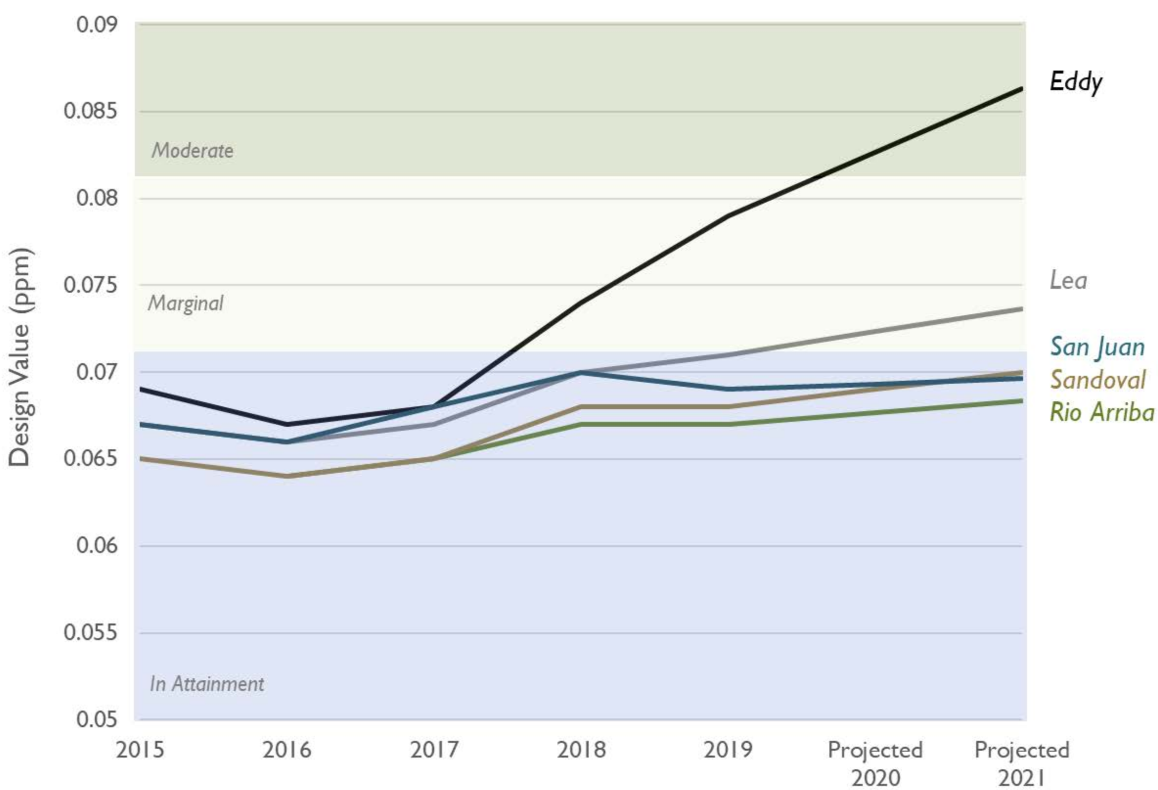
Atmospheric concentrations of ozone in the state of New Mexico have risen rapidly in recent years, increasing the risk of violating the U.S. EPA's National Ambient Air Quality Standards (NAAQS) for ground-level ozone. Many of the increases in ozone are concentrated in areas of increasing oil and gas production and, therefore, increasing air pollution. VOCs react with NO_X to generate ozone, so regulatory actions to limit VOC emissions from the oil and gas industry should reduce ozone concentrations, all else being equal. Failure of a county to meet the EPA's ozone threshold of 70 parts per billion (ppb) results in both direct and indirect economic costs to residents and businesses in the area (in addition to the human health costs discussed above). For example, once an area is in nonattainment (i.e., has exceeded the ozone threshold), new potential sources of emissions must be reviewed through a permitting process and various programs related to transportation emissions become required. If emissions are not brought down quickly, further measures may be imposed. These measures can impede economic development by requiring greater investment in pollution controls for expanded or new facilities. This process creates localized costs of doing business that could encourage development to happen elsewhere—in a different county of New Mexico or in another state entirely.

Nonattainment is classified in multiple levels of severity depending on ozone concentration. Each level has its own requirements that become more severe and require more time for remediation at higher ozone concentration levels. In our analysis, we examined data from the five counties in New Mexico with EPA air monitoring stations that overlapped with our emissions data.[6] Nonattainment classification is based on the "design value," which is the three-year average of the monitor's fourth highest eight-hour average ozone reading in each year. Among the five oil and gas producing counties, only Eddy and Lea Counties had locations with design values above the nonattainment threshold as of the end of 2019. It is impossible to determine exactly how severe future ozone design values will be, but an estimate can be obtained through historical growth rates in annual ozone values. Figure 1 shows this increase in

[6] Other counties may have poor or worsening air quality but are not monitored.

ozone design values (three-year average) between 2015–2021, with 2020 and 2021 representing projected values. Design values for 2020 and 2021 are calculated by continuing the average growth trajectory of the three previous years. Assuming this conservative level of growth, by 2021 Eddy County will enter moderate nonattainment and Lea County remains in marginal nonattainment. Design values for Rio Arriba, Sandoval, and San Juan Counties under these assumptions would be under 70 ppb and thus technically in attainment by 2021; but increases in their annual ozone values would push those counties into nonattainment as well.

Figure 1. Projected ozone design values to 2021



Source: Synapse calculations based on EPA historical design values.

Our projection supports the idea that nonattainment is an imminent threat and the resulting regulatory costs are highly probable in the near term unless actions are taken. The proposed rules could help the state avoid the costs associated with nonattainment, as well as avoid the human health impacts of higher ground-level ozone levels. Once a county falls into a nonattainment status of moderate or above, the state must file a state implementation plan (SIP) that outlines its path to compliance. At the moderate nonattainment level, the SIP must include developing a major emissions statement and conducting a transportation conformity demonstration, including a motor vehicle emissions budget. Furthermore, all major emissions sources greater than 100 metric tonnes per year must go through new source review and permitting. These major emissions sources are also required to purchase offset credits to ensure there is no increase in emissions. At the moderate level, there is also the requirement to impose reasonably available control technology on all major emitting sources, reduce VOC emissions by 15 percent of the county's baseline, and impose a vehicle inspection and maintenance program.

For our analysis, we modeled avoided costs based on a moderate nonattainment level using information from two reports from Texas, one developed by the Capital Area Council of Governments (CAPCOG) and the other conducted for the Alamo Area Council of Governments focusing on the San Antonio metropolitan area.[7,8] These studies occurred after NAAQS standards were made more stringent—decreasing from 75 ppb to 70 ppb in 2015—after which a number of counties fell into nonattainment, including those outlined in these reports. It is difficult to quantify the specific costs of compliance actions because, while there are general benchmarks that must be met, how a state decides to meet them can be very different. Our analysis attempted to quantify the hard costs associated with nonattainment, including permitting, offsets, and vehicle inspection and maintenance. Because our analysis is forward-looking, we could not reasonably estimate some of the softer costs associated with nonattainment, such as the loss of business expansion due to permitting costs.

Overall, the most significant costs identified in our nonattainment analysis stem from increased permitting costs and the cost of offset purchases. These costs are incurred because any new major emitting source above 100 tonnes per year of NO_X or VOCs that is built in the state under nonattainment must go through a special permitting process. In addition, any new emissions source must purchase offset credits equal to 1.15 times the tonnes per year amount in the permit. Using data from the New Mexico Environment Department Air Quality Bureau, we were able to approximate the size and quantity of permits by county. We took offset prices from 2017 California Air Resources Board (CARB) data and used them to determine total offset costs.[9] The costs of vehicle inspection and maintenance programs were calculated using inspection and repair costs outlined in the Texas reports multiplied by the number of vehicles in New Mexico. We calculated vehicle quantities using populations by county and motor vehicle registrations in the state to determine vehicles per county. Finally, the cost of a 15 percent reduction in VOCs was calculated using EPA data of VOC emissions in the state of New Mexico and CAPCOG's estimate of the cost per tonne of VOC reduction.[10]

[7] Capital Area Council of Governments (CAPCOG). 2015. *The Potential Costs of Ozone Nonattainment Designation to Central Texas*. Available at: http://www.capcog.org/documents/airquality/reports/2015/Potential_Costs_of_a_Nonattainment_Designation_09-17-15.pdf.

[8] Navin, S. et al. 2017. *Potential Cost of Nonattainment in the San Antonio Metropolitan Area*. Available at: https://www.tceq.texas.gov/assets/public/agency/nc/air/Appendix-B-for-EPA-HQ-OAR-2018-0635.pdf.

[9] California Air Resources Board, New Source Review - Emission Reduction Credit Offsets. Available at: https://ww3.arb.ca.gov/nsr/erco/erc17.pdf. Accessed 2019.

[10] CAPCOG. 2015. *The Potential Costs of Ozone Nonattainment Designation to Central Texas*. Pg. 77.

Value of Captured Gas

Methane that is produced (either as the primary product or associated with oil production) can have one of three fates: (1) it is captured into the pipeline infrastructure and carried downstream to eventual customers; (2) it is lost or purposely emitted into the atmosphere; or (3) it is burned in a flare. One effect of the proposed regulations would be shifting methane that would have been emitted or flared into the captured category. Captured gas has economic value, so the increased capture results in an economic benefit attributable to the regulation.

Synapse calculated the value of the captured gas to gas producers in New Mexico using a method based on revealed market prices, combined with expert assessment of the impact of increased gas pipeline capacity. Gas prices paid to producers in New Mexico are lower than the Henry Hub price (the most common national benchmark for natural gas prices) because of the cost to transport gas to the national market. This difference between Henry Hub and New Mexico gas prices is called the "basis."

In New Mexico, oil and gas is primarily produced in two locations: the Permian Basin (southeastern New Mexico) and the San Juan Basin (northwestern New Mexico). We used market forward prices from CME Group for basis futures in the Permian and San Juan areas to calibrate current expected basis estimates.[11,12] At each location, we calculated the average expected future basis for the next 18 months (through the end of 2021). In the Permian Basin, this average is $0.39 per mcf, while in the San Juan Basin the average is $0.30 per mcf. These 18-month averages are also very close to the midpoint between the highest and lowest monthly expected bases in each basin.

We used the market projections of the Henry Hub natural gas price as revealed in the price of market forward purchases on the NYMEX exchange.[13] These values tend to be lower than the U.S. Energy Information Administration's projections from the Annual Energy Outlook, so the gas value reflected using these prices is a conservative estimate. In 2019 dollars, the market projection of Henry Hub prices is nearly flat, ranging between $2.23 per mcf and $2.29 per mcf in all years except for 2021 and 2022, when the futures market expects somewhat higher prices ($2.59 and $2.39 per mcf, respectively).

Pipeline capacity out of both the Permian and San Juan production areas is currently constrained. This is demonstrated by the fact that the value of gas in New Mexico is substantially lower than the national Henry Hub price. Pipeline companies have begun substantial new investments in pipeline capacity to relieve these constraints. For example, the U.S. Energy Information Administration is tracking the progress of six announced pipelines or expansions to transport gas from the Permian Basin, totaling over

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[11] CME Group, "Permian Natural Gas (Platts IFERC) Basis Futures Quotes." Accessed July 31, 2020 at https://www.cmegroup.com/trading/energy/natural-gas/el-paso-permian-basin-natural-gas-basis-swap-futures-platts-iferc.html.

[12] CME Group, "San Juan Natural Gas (Platts IFERC) Basis Futures Quotes." Accessed July 31, 2020 at https://www.cmegroup.com/trading/energy/natural-gas/san-juan-basin-natural-gas-basis-swap-futures-platts-iferc.html.

[13] CME Group, "Henry Hub Natural Gas Futures Quotes." Accessed July 31, 2020 at https://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

8.4 billion cubic feet (Bcf) per day. Three new pipelines or expansions totaling 2.43 Bcf per day of capacity came online in 2019.[14] As these pipelines enter service, the basis should decline. McKinsey & Company estimates that the basis should shrink to $0.10 per mcf once the constraints are relieved.[15] This remaining cost reflects the continued cost of transporting the gas away from New Mexico to the national market. We assumed that this new equilibrium would be established by 2025, with the basis declining linearly to $0.10 per mcf between 2021 and 2025. Subtracting the basis projection from the Henry Hub projection results in a projected net value of gas to New Mexico producers, by region (Figure 2).

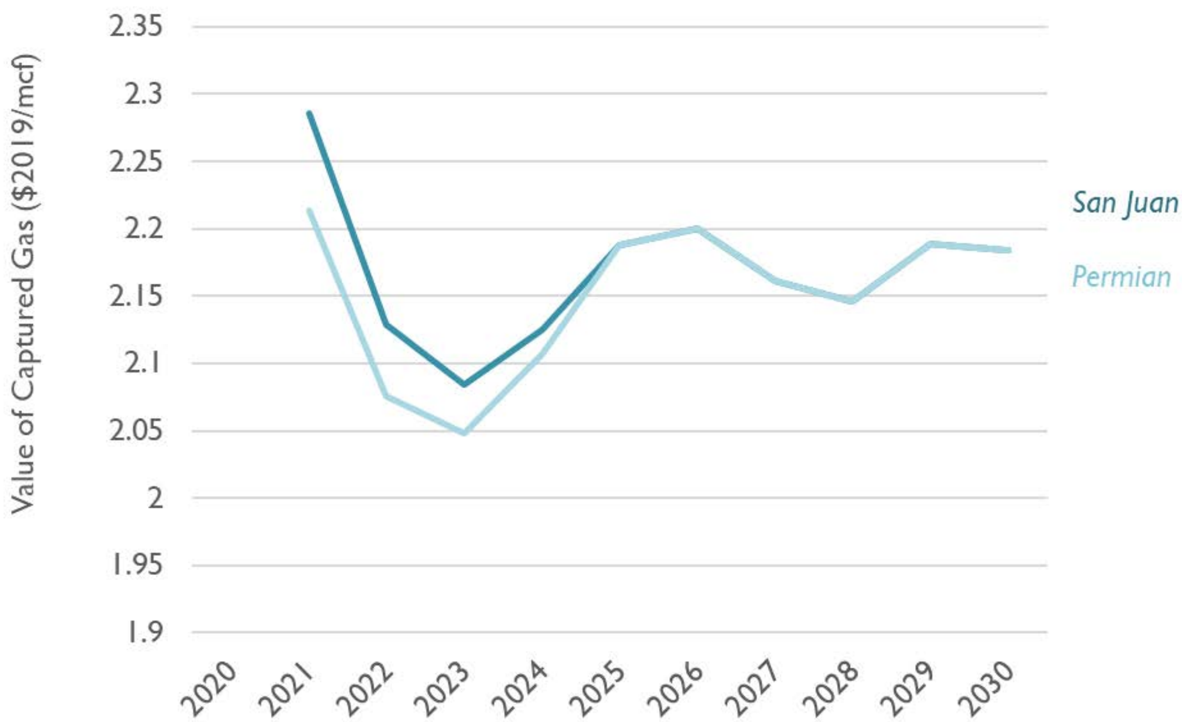
The State of New Mexico will see some direct fiscal benefit from the increased capture and sale of gas resulting from these regulations, including federal royalties that are returned to the state, state trust royalties, emergency school tax, severance tax, conservation tax, and ad valorem production tax.[16] The county-specific fractions of the gas value that would flow as royalties were provided directly by Spherical Analytics. Though the fiscal benefit from increased royalties does not impact the BCRs, we present the percentage of royalty benefit and absolute fiscal benefit by county in New Mexico.

[14] U.S. Energy Information Administration, “Pipeline projects.” Accessed August 10, 2020 at https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

[15] Brick, J. 2018. “Permian, we have a gas problem(s).” McKinsey & Company, July 1, 2018. https://www.mckinsey.com/industries/oil-and-gas/our-insights/petroleum-blog/permian-we-have-a-gas-problems.

[16] The tax calculations assume that 49 percent of federal royalties (a rate of 12.5 percent) are returned to the state of New Mexico; the state trust royalty tax rate is 19 percent; emergency school tax is 4 percent, severance tax is 3.75 percent; conservation tax is 0.19 percent; and the ad valorem tax varies by land type (ranging from 0.82 percent on tribal land to 1.39 percent on private land).

Figure 2. Projected value of captured gas in the San Juan and Permian regions, 2020–2030



Source: Synapse calculations based on market futures prices for Henry Hub natural gas prices and near-term bases.

Avoided Greenhouse Gas Costs

Synapse quantified the impact that reducing methane emissions has on mitigating climate change, including reducing damages associated with the spread of disease, coastal destruction, and decreased food security. We applied the societal cost of methane calculated by the U.S. Government Interagency Working Group (IWG) in 2016, as calculated using a 3 percent real discount rate.[17] The 3 percent discount rate was selected for this analysis because the IWG considers it a central estimate based on average climate outcomes. This cost is equivalent to $1,462 per tonne of methane in 2020 and escalates to $1,949 per tonne in 2030 (2019 dollars).

[17] Interagency Working Group on Social Cost of Greenhouse Gases. 2016. Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide. Available at: https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf.

2.2. Cost Estimation

Oil and gas producers in New Mexico will incur costs in order to comply with the proposed rules. Synapse researched and compiled compliance costs by source of methane on a dollar-per-mcf and dollar-per-metric-tonne basis. We then calculated total costs by county using annual methane and VOC emissions reduction potential provided by Spherical Analytics.

The 15 emissions sources outlined in our study can be broadly classified in two categories: vented and fugitive emissions. Vented emissions are the intentional release of gases (e.g., flaring and venting), while fugitive emissions are the result of unintentional gas leaks from various valves, pumps, and other equipment throughout the production, gathering, and boosting processes. Reductions in vented emissions are primarily accomplished through increasing gas capture with vapor recovery units (VRU) and zero-emissions equipment. Reductions in fugitive emissions come from quarterly leak detection and repair (LDAR).

The proposed state emissions rules address only fugitive methane emissions, as they do not address gas venting and flaring. Within the category of fugitive emissions, the largest methane reduction potential comes from equipment malfunctions (i.e., "abnormal emissions"), which represent 79 percent of the total methane emission reduction potential and 65 percent of VOC reduction. Abnormal emissions are measured by comparing the difference between top-down site-level measurements and bottom-up aggregation of source-level emissions.[18] Total site emissions can be calculated by using optical gas-imaging cameras downwind of production facilities.[19]

[18] Zavala-Araiza, D. et al. 2017. *Super-emitters in natural gas infrastructure are caused by abnormal process conditions*. Available at: https://www.nature.com/articles/ncomms14012.

[19] EDF Methodology. Available at: https://www.edf.org/nm-oil-gas/methodology/. Accessed 2019.

Table 1. Emissions sources and corresponding abatement technology and unit cost

Emission Source	Technology	Unit Cost ($/mcf of reduced methane)	Unit Cost ($/tonne of reduced methane)	Source
Abnormal Emissions	*Quarterly LDAR**	$0.00	$0.00	ICF, 2015
Associated gas flaring	VRU	$4.18	$217.36	CARB, 2017
Associated gas venting	VRU	$4.18	$217.36	CARB, 2017
Centrifugal compressors	Wet Seal Degassing Recovery System for Centrifugal Compressors	$0.82	$42.64	CARB, 2017
Dehydrators	VRU	$4.18	$217.36	CARB, 2017
Gathering station blowdowns	Transmission Station Venting -Redesign Blowdown Systems /ESD Practices	$3.84	$199.68	ICF, 2016
Gathering stations	LDAR (weighted average)	$7.35	$382.20	ICF, 2015
High-bleed pneumatic controller	High-bleed to zero-bleed pneumatic controller	$7.89	$410.14	Carbon Limits, 2016
Leaks	LDAR (weighted average)	$7.35	$382.20	ICF, 2015
Liquids unloading	Liquid Unloading - Install Plunger Lift Systems in Gas Wells	$5.03	$261.56	ICF, 2016
Low-bleed pneumatic controller	Low-bleed to zero-bleed pneumatic controller	$49.30	$2,563.40	Carbon Limits, 2016
Malfunctioning pneumatic controllers	*Quarterly LDAR**	$0.00	$0.00	ICF, 2015
Oil and condensate tanks	VRU	$4.18	$217.36	CARB, 2017
Pneumatic pump	Solar electric pneumatic pump replacement	$4.86	$217.36	ICF, 2016
Reciprocating compressors	Replacement of Reciprocating Compressor Rod Packing Systems	$1.83	$95.16	CARB, 2017

Note: Abnormal emissions and malfunctioning pneumatic controllers are addressed by quarterly LDAR for leaks and gathering stations, therefore their costs are not repeated.

All types of fugitive emissions can be mitigated through LDAR. LDAR is one of the most common emission mediation methods and is relatively inexpensive to implement on a cost-per-volume basis. The cost of LDAR is primarily associated with the labor cost of sending a technician to the site. We assume that all abnormal emissions (including those from malfunctioning pneumatics) will be identified and addressed as part of the quarterly LDAR process. Therefore, we conclude that there is no additional cost associated with those two source categories.

Retrofitting high- and low-bleed pneumatic controllers with zero-bleed alternatives represents the second-largest emissions reduction category (7 percent). Pneumatic controllers are also the most significant cost driver, as there is a higher capital cost relative to the volume of gas savings. It should be noted that all costs per unit of emissions reduction are variable, and this is particularly true for zero-bleed systems. In the face of this variability we have taken a conservative approach which likely over-represents these costs.

Sources of Cost Data

Synapse compiled abatement technology cost data from several sources. Given that LDAR makes up a substantial portion of the emissions reductions in this analysis, we utilized a source specific to LDAR that calculated costs using facility models and Monte Carlo simulations.[20] Zero-bleed pneumatic controller costs were calculated using a Carbon Limits tool developed for the Clean Air Task Force.[21] For the remaining technologies, we use a 2017 CARB report for the costs it contains (including VRU, wet seal degassing, and reciprocating compressors) because it was the most recent source of methane abatement technology costs.[22] The remainder of costs that were not covered by other more recent sources were sourced from two reports by ICF International, one prepared for EDF in 2014 and the other prepared for One Future, Inc. in 2016.[23] In all cost categories for which we relied on an ICF International report, the two reports agreed and we have cited the 2016 report. Table 1 summarizes each emissions source analyzed by Spherical, the technology used, and the cost of emissions reduction on a dollar-per-mcf and dollar-per-tonne basis.

3. Benefit-Cost Results

3.1. Benefit-Cost Ratio Definitions

Comparing the benefits and costs described above yields a BCR with the discounted benefits in the numerator and the discounted costs in the denominator. A BCR above 1 indicates that the program is cost-effective because the total lifetime benefits outweigh the total lifetime costs of the regulation. In contrast, a BCR below 1 indicates that the program is not cost-effective because the costs are higher than the benefits. All costs and benefits in this analysis were discounted at a rate of 3 percent and in constant 2019 dollars. Synapse calculated three distinct BCRs, each different in which benefits are included in the numerator of the ratio:

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[20] ICF International. 2015. *Leak Detection and Repair Cost-Effectiveness Analysis* (Revised 2016). Available at: https://www.edf.org/sites/default/files/content/edf_ldar_analysis_120415_v7.pdf.

[21] Carbon Limits. 2016. *Zero emission technologies for pneumatic controllers in the USA*. Available at: https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf.

[22] California Air Resources Board. 2017. Regulation for greenhouse gas emission standards for crude oil and natural gas facilities, Attachment 2. Available at: https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf

[23] ICF International. 2014. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. Available at: https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf; ICF. 2016. *Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems*. Available at: http://onefuture.us/wp-content/uploads/2018/05/ONE-Future-MAC-Final-6-1.pdf

1. **New Mexico BCR**: This ratio includes the benefits of captured gas, avoided health impacts for New Mexico, and the value of avoided NAAQS nonattainment. These benefit streams are the most tangible benefits to New Mexicans. Though the NAAQS nonattainment benefits have a high degree of uncertainty, we consider this ratio to be conservative because the local health benefits associated with reduced ground-level ozone are not included.

2. **National BCR**: In addition to the benefits of the New Mexico BCR, this ratio also includes the avoided health impacts for the rest of the contiguous United States. This ratio quantifies the benefits of the proposed rules to the entire country.

3. **Global BCR**: In addition to the benefits of the National BCR, this ratio also includes the greenhouse gas benefit of avoided methane emissions. This benefit is only included in the Global BCR because the value will accrue to the benefit of people around the world, rather than just to Americans.

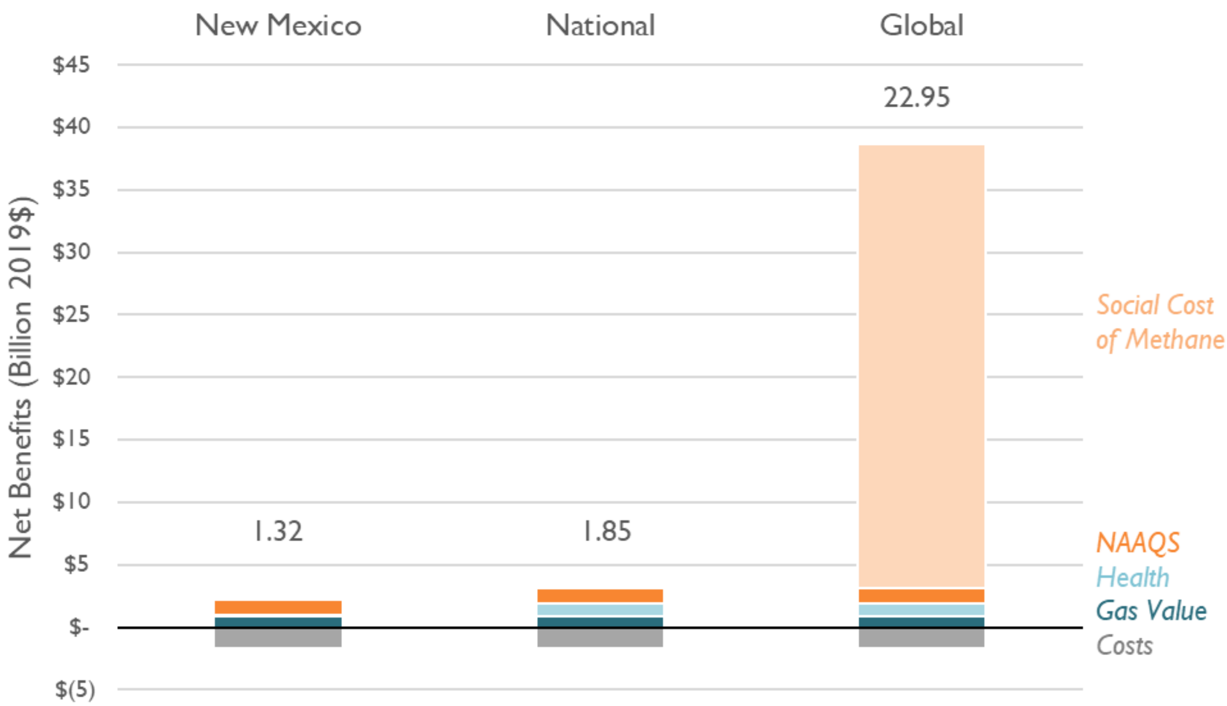
3.2. Overview of Results

The proposed oil and gas emission reduction rules were found to be cost-effective across all three BCRs. The New Mexico BCR, which is considered the most conservative ratio, is 1.32 over the 11-year study period. If negative health impacts from ground-level ozone were quantified, this ratio would be higher. Based on this perspective, for every $1 million of costs associated with the proposed rules, New Mexicans are expected to benefit by at least $1.32 million from captured gas revenue, reduced health-related costs, and reduced NAAQS compliance costs. This translates to a net benefit of $0.49 per mcf of recovered methane.

The National BCR, which also includes the human health benefits to the rest of the contiguous United States from particulates associated with reduced VOC emissions, is 1.85 over the 11-year study period. In this case, for every $1 million of costs associated with the comprehensive controls, the United States is expected to benefit by at least $1.85 million from captured gas revenue, reduced health-related costs, and reduced ozone regulation compliance costs. This translates to a net benefit of $1.30 per mcf of recovered methane.

Finally, the Global BCR—which includes all benefits from the National BCR, plus the avoided social cost of methane—is 22.95 over the 11-year study period. For every $1 million of costs associated with the proposed rules, we calculate a global benefit of at least $22.95 million from captured gas revenue, reduced health-related costs, reduced ozone regulation compliance costs, and mitigation of climate change. This translates to a net benefit of $33.36 per mcf of recovered methane.

Figure 3. Net benefits and benefit-cost ratios for the proposed rules in New Mexico



Source: Synapse calculations.

3.3. Cost Summary

In total, the comprehensive controls are expected to achieve a 450 million mcf reduction in methane emissions and nearly 3 million tonnes reduction of VOCs from 2020–2030. The total compliance cost of $1.7 billion translates to $3.75 per mcf of methane reduced or $195.50 per tonne of methane gas emissions reduced, in 2019 dollars. Furthermore, this translates to $573.40 per tonne of VOC reduced. About 77 percent of the cost is associated with zero-bleed controllers.

Table 2. Total cost of methane and VOC reduction by emissions source

Emission Source	Methane Reduction (million mcf)	VOC Reduction (thousand tonnes)	Discounted NPV Cost (2019$ millions)
Abnormal Emissions	354	1,920	$0
Gathering Stations	19	105	$127
High-Bleed Pneumatic Controller	2	8	$12
Leaks	26	116	$177
Liquids Unloading	13	47	$57
Low-bleed Pneumatic Controller	29	118	$1,271
Oil and Condensate Tanks	5	618	$19
Pneumatic Pump	2	10	$11
Total	**1,199**	**6,959**	**$1,684**

Source: Spherical Analytics (emissions reductions) and Synapse calculations (costs). Values may not sum to total due to rounding.

3.4. Benefits Summary

Human Health

Reduced VOC emissions lead to lower human mortality, illnesses, and associated detriment to the economy. Though the VOC emission reductions originate in only nine of New Mexico counties, the benefits are reaped across the state as well as the country. Across New Mexico, the total discounted value of this subset of human health benefits amounts to just over $126 million over the 2020–2030 study period. Within New Mexico, 87 percent of the health benefits from reduced VOC emissions are reaped in the nine counties where the emissions originate. Across the entire United States, the total discounted value of these health benefits amounts to about $1 billion over the study period.

Note that these benefits do not include those associated with reduced ground-level ozone (resulting from reduced VOC emissions). As such, we consider this category of benefits to be conservative. Actual benefits are likely to be higher than what is estimated in this report.

NAAQS Avoided Nonattainment Costs

In total we found moderate nonattainment would cost the five New Mexico counties a total of $1.2 billion (over a six-year nonattainment time period at a 3 percent discount rate), but we expect the actual impact could be much higher. This analysis excludes costs associated with project delays, decreases in gross regional product (GRP) due to loss of business expansion, and costs of point source emissions reductions through reasonably available control technology.[24] While more localized to individual businesses, the softer costs of nonattainment may have large effects on the local economy. These localized impacts were outside the scope of this analysis. Therefore, we note that our estimate of

[24] Both Texas studies were able to approximate these costs, finding tens of billions of dollars in losses in GRP.

avoided nonattainment benefits is very conservative, and the BCRs are likely higher than calculated in this report.

Table 3. Present value of cost of moderate nonattainment

Measure	Discounted NPV (Millions 2019$)
NSR Permitting	$23
Offset	$647
Transportation Conformity	$0.04
Vehicle I-M	$10
15% VOC RFP	$541
Total	**$1,220**

Source: Synapse calculations.

Examining each county individually, we found that the total costs at risk range from $62 million in Sandoval County to $416 million in San Juan County (Table 4).

Table 4. Discounted value of avoided NAAQS nonattainment costs for 2020–2030, by county

County	Discounted NPV (Millions 2019$)
Chaves	-
Colfax	-
Eddy	$236
Lea	$369
McKinley	-
Rio Arriba	$138
Roosevelt	-
San Juan	$416
Sandoval	$62
All	**$1,220**

Source: Synapse calculations. Note: Chaves, Colfax, McKinley, and Roosevelt Counties do not have air quality monitoring stations; therefore, we could not conduct the analysis for those four counties.

Value of Captured Gas

The value of captured gas from the comprehensive controls over the period of 2020 to 2030 varies greatly by county, from about $416,000 (McKinley) to just over $320 million (Eddy). This variation is due in large part to the volume of captured gas in each county and in small part to the difference in gas value between the Permian and San Juan Basins. The total discounted value of captured gas from the comprehensive controls over the 11-year study period is nearly $730 million (Table 5). Of this value, approximately 14 percent ($99 million) is expected to be realized by the State of New Mexico in gas royalties.

Table 5. Discounted value of captured gas and royalty revenues for 2020–2030, by county

County	Discounted NPV (Millions 2019$)	Royalty Revenue (Millions 2019$)	Percent of Revenue for Royalties
Chaves	$32	$4	13%
Colfax	$9	$0.8	9%
Eddy	$267	$37	14%
Lea	$252	$33	13%
McKinley	$0.3	$0.1	15%
Rio Arriba	$67	$9	14%
Roosevelt	$3	$0.3	10%
San Juan	$95	$13	14%
Sandoval	$3	$0.4	15%
All	**$728**	**$99**	**14%**

Source: Synapse calculations (discounted NPV) and Spherical Analytics calculations (royalty percentages). Values may not sum to totals due to rounding.

In a similar analysis, the Colorado Division of Public Health and Environment (CDPHE) conducted a cost-benefit analysis of Colorado's emissions regulations. Its analysis aligned with our findings, concluding that the emissions regulations are cost-effective.[25] Furthermore, CDPHE found total annual costs of $59.2 million compared to $16.8 million in captured gas value, representing 28 percent of cost recovery. In our analysis, we calculated 10-year costs at $6.4 billion and a value of captured gas of roughly $2 billion, or 31 percent of total costs. In its analysis, CDPHE found that the costs to oil and gas companies only represented 0.4 percent of their annual revenues and that regulations would be unlikely to cause price impacts to consumers. In fact, major oil and gas companies in Colorado supported these regulations.

Avoided Greenhouse Gas Costs

Reducing methane emissions has a long-term global benefit: mitigating the costly effects of climate change (e.g., sea-level rise and property damage, increased transfer of illnesses, ecological damage). The total discounted value of this global benefit amounts to $12.3 billion over the 2020–2030 study period (Table 6). McKinley County would generate the least of these benefits ($6 million), while Eddy County would generate the greatest of these benefits ($4.5 billion).

[25] Colorado Department of Public Health and Environment. 2014. *Cost Benefit Analysis*. Available at: http://www.ematrix.erg.com/files/control/BP%20Doc%20Colorado%201.pdf.

Table 6. Discounted value of avoided social cost of methane for 2020-2030, by county

County	Discounted NPV (Millions 2019$)
Chaves	$540
Colfax	$15
Eddy	$4,500
Lea	$4,260
McKinley	$6
Rio Arriba	$1,120
Roosevelt	$44
San Juan	$1,580
Sandoval	$50
All	**$12,250**

Source: Synapse calculations. Values may not sum to total due to rounding.

4. CONCLUSIONS

To calculate the cost-effectiveness of the proposed oil and gas emission rules in New Mexico, Synapse evaluated three BCRs of the regulation for 2020 through 2030, each with different combinations of benefit streams but the same cost assumptions. Where cost choices were available, higher technology cost assumptions were chosen to be as conservative as possible. These ratios range from conservative to comprehensive and are termed the New Mexico BCR, the National BCR, and the Global BCR. A BCR greater than 1 is considered cost-effective because the total benefits over the study period are greater than the total costs. Based on this analysis, we determined that the proposed rules are cost-effective without the existing exemptions, regardless of which BCR is used.

Synapse considers the New Mexico BCR the most conservative ratio, inclusive of benefit streams that are readily quantifiable and have a direct and tangible impact on New Mexicans. The benefits calculated as part of this ratio include only the avoided human health costs (due to reduced air pollution) for New Mexicans, the avoided NAAQS nonattainment costs, and the value of captured (i.e., non-leaked or non-vented) methane that supports the state's economy. Though nonattainment has both direct and indirect costs, Synapse limited the analysis to the direct costs, including permit and transportation programmatic costs. The resulting New Mexico BCR is 1.32.

The National BCR includes the benefits of the New Mexico BCR, plus the human health benefits reaped across the entire county. This ratio speaks to the cost-effectiveness of the proposed rules for the entire United States. The resulting National BCR demonstrates even greater cost-effectiveness, with a ratio of 1.85.

Finally, the Global BCR takes the most comprehensive view of benefits, including long-term climate benefits to the global population—not just to New Mexicans or Americans. The Global BCR includes all benefits from the National BCR, plus the avoided social cost of methane associated with methane's greenhouse gas effect on climate change. The resulting Global BCR is 22.95, demonstrating the substantial global benefits that would flow from reducing methane emissions.

This study illustrates that, regardless of the perspective of benefits, the proposed oil and gas emissions rules are cost-effective without the exemptions for sites with stripper wells or wells with a potential to emit less than 15 tons per year of VOCs.

APPENDIX A. COST CALCULATIONS

The Carbon Limits tool used in this analysis estimated methane abatement costs by calculating 10-year lifetime capital costs of the project and emissions reductions from a zero-bleed controller. Key inputs and assumptions that affected the final cost in dollars per tonne of methane emissions avoided include the number of controllers at a site, the emissions factor of a high- and low-bleed controller in cubic feet per hour, and the capital costs of the project. Included in the capital cost are the controllers, control panel, solar panel, battery backup, as well as replacement batteries and labor over the lifetime of the project. We made a conservative assumption that there is no electric connection at these sites to power the controllers and that all devices are paired with solar and battery storage. Upfront capital costs for the project totaled $35,640 for an average site retrofit with six continuous bleed controllers (Table 7). Additional operating costs include $1,200 every four years for battery replacement and $480 annually for labor cost.

Table 7. Upfront capital cost of an average zero bleed controller retrofit

Type	Unit Cost	Units	Total Cost
Continuous Controller	4,000	6	$24,000
Control Panel	4,000	1	$4,000
Solar Panel	500	1	$500
Battery	400	3	$1,200
Installation Cost		20% of CAPEX	$5,940
Total			**$35,640**

The largest driver of the abatement cost for zero-bleed controllers was the emissions rate. Additionally, capital costs were the same between high- and low-bleed retrofits, therefore high-bleed devices had a much lower cost per mcf of methane emissions avoided comparative to low-bleed because their emissions reduction potential is greater. We used EPA's reported emissions rate of 13.75 standard cubic feet per hour (scfh) for high-bleed devices and 2.17 scfh for low-bleed.[26] Controllers per site was taken from a University of Texas at Austin study that sampled the number of controllers at 65 sites throughout the United States.[27] Overall, high-bleed controllers had an abatement cost of $7.89 per mcf of methane compared to a low-bleed retrofit at $49.3 per mcf.

[26] EPA. 2014. *Oil and Natural Gas Sector Pneumatic Devices*. High and low bleed available in table 2-4 at: https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf.

[27] Allen, D. et al. 2014. *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*. Available at: https://pubs.acs.org/doi/pdf/10.1021/es5040156?rand=pedkv1qx.

APPENDIX B. NAAQS – NONATTAINMENT

Nonattainment costs are composed of offset trading, 15 percent baseline VOC reduction, vehicle inspection and maintenance, new source review and permitting, and transportation conformity costs. Costs were dominated by offsets and VOC reduction which together accounted for 97 percent of the total.

We approximated air permitting and offset costs using publicly available data sources through the New Mexico Environment Department Air Quality Bureau. For permitting cost, we used the annual number of new permits by county and cost per permit. First, we found the percentage of total Title V permits (major emissions sources greater than 100 tonnes per year) by county by taking total permits by county divided by the total permits in the state from the “Permitted Facilities Lat Long” dataset.[28] Then, annual permitting data between 2016 and 2018 was used to calculate the average number of new permits granted by year in New Mexico.[29] Between 2016 and 2018 there were 31 new Title V permits on average. To find new permits by county, we multiplied the county-level distribution percentage by the annual average number of Title V permits in the state of New Mexico. S. Navin, et al. estimated permitting costs between $100,000 and $250,000; therefore, we used the average for our cost and multiplied by annual permit count to get total cost (Table 8).[30]

Table 8. Average Title-V permitting distribution and cost by county

County	Title-V (%)	Annual Permit Count	Average Permit Cost	Annual Permit Cost	Six-Year Permit Costs
Eddy	20.9	6	$175,000	$1,050,000	$6,951,647
Lea	18	6	$175,000	$1,050,000	$6,951,647
Rio Arriba	7.6	2	$175,000	$350,000	$2,317,215
Sandoval	21.5	7	$175,000	$175,000	$1,158,607
San Juan	2.9	1	$175,000	$1,225,000	$8,110,255
ALL	**70.9**	**22**	**$175,000**	**$3,850,000**	**$25,489,373**

Source: Synapse calculations.

[28] At the time of our analysis, we used the file “Permitted Facilities Lat Long as of 07/01/19.” Current version is as of 09/03/19. Available at: https://www.env.nm.gov/air-quality/aqb-p_current_permitting_activites/.

[29] New Mexico Environment Department. Monthly Report of Title V Permitting Activities Fiscal Year 2016-2018. Available at: https://www.env.nm.gov/air-quality/monthly-report-of-permitting-statistics/.

[30] Navin, S. et al. 2017. *Potential Cost of Nonattainment in the San Antonio Metropolitan Area*. Available at: https://www.tceq.texas.gov/assets/public/agency/nc/air/Appendix-B-for-EPA-HQ-OAR-2018-0635.pdf.

Under moderate nonattainment, any new major emissions source must also supply an offset equal to 1.15 times the amount specified in its permit. For offset cost we multiplied the annual number of permits filed by county and the average permit size in tonnes of both NO_x and VOC that we calculated from our initial "Permitted Facilities Lat Long" dataset. We used the maximum value between VOC and NO_X to calculate the total required offset amount. Offset costs were taken from CARB offset transactions from 2017 for both NO_X and VOCs. Average NO_X offset costs per tonne were $13,883 and VOC were $6,242 per tonne. We used the average of the two offset costs (Table 9).[31]

Table 9. Average Title-V emissions and offset costs by county

County	NO_X (tonnes/year)	VOC (tonnes/year)	Offset Amount (tonnes)	Offset Cost ($/tonne)	Annual Offset Cost	Six-Year Offset Cost
Eddy	176.6	197.1	1360.1	10,062.5	$13,686,078	$90,610,270
Lea	587.6	134.4	4054.6	10,062.5	$40,799,348	$270,116,834
Rio Arriba	188.2	200.6	461.3	10,062.5	$4,641,746	$30,731,220
Sandoval	82.1	53.3	94.4	10,062.5	$950,051	$6,289,922
San Juan	589.5	164.3	4745.3	10,062.5	$47,749,655	$316,132,149
ALL	**1,624.0**	**749.7**	**10,715.7**	**10,062.5**	**$107,826,877**	**$713,880,398**

Source: Synapse calculations.

We calculated costs associated with 15 percent VOC reductions by using EPA National Emissions Inventory Data VOCs from 2014 and CAPCOG's cost in dollars per tonne of VOC emission reductions (Table 10).[32]

[31] California Air Resources Board. 2017. New Source Review – Emissions Reduction Credit Offsets. Available at: https://ww3.arb.ca.gov/nsr/erco/erc17.pdf.

[32] EPA National Emissions Inventory Data 2014. https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data.

Table 10. Estimation of 15 percent VOC reduction costs by county, 2020–2030

County	VOC Baseline (tonnes)	Reduction (tonnes)	VOC Reduction $/ton	Total Cost
Eddy	122,785.6	18,417.8	7,965	$161,871,974
Lea	97,680.2	14,652.0	7,965	$128,774,782
Rio Arriba	89,329.0	13,399.3	7,965	$117,765,088
Sandoval	43,329.6	6,499.4	7,965	$57,122,698
San Juan	99,706.6	14,956.0	7,965	$131,446,167
All	**452,831.0**	**67,924.5**	**7,965**	**$596,980,711**

Source: Synapse calculations.

The remainder of costs were relatively small in comparison to offsets, and VOC reduction represented just 3 percent of total costs. A transportation conformity analysis estimated at $0.10 per person by CAPCOG was multiplied by county-level census data to get total costs.[33] Similarly, vehicle inspection and maintenance was calculated using county-level population data in addition to vehicle registration data and CAPCOG cost estimations. CAPCOG estimated inspection and repair costs as well as the percentage of vehicles that would require repair of the total vehicles inspected. From those estimations, we calculated an average cost per vehicle at $26.26 which includes initial inspection and a percentage of total vehicles that would require a secondary inspection and repair. Using total New Mexico vehicle registrations, we determined a statewide vehicles-per-person number based on state population. This ratio of .87 vehicles per person was multiplied by total population by county and finally by the cost of $26.26 per vehicle for a total shown in Table 11.

Table 11. Vehicle inspection and maintenance and transportation conformity costs based on county population

County	Population	Vehicles	I-M Cost	Transportation Conformity Cost
Eddy	57,900	50,385	$1,459,913.18	$6,388.89
Lea	69,611	60,576	$1,755,198.90	$7,681.13
Rio Arriba	39,006	33,943	$983,512.49	$4,304.06
Sandoval	145,179	126,335	$3,660,599.92	$16,019.57
San Juan	125,043	108,813	$3,152,882.96	$13,797.70
All	**436,739**	**380,051**	**$11,012,107.45**	**$48,191.36**

For other cost calculations including LDAR, wet seal degassing for centrifugal compressors, and replacement of reciprocating compressor rod packing systems, we utilized values from a CARB proposed

[33] County-level population data taken from U.S. Census Bureau. https://www.census.gov/.

regulation.[34] CARB reported emissions reductions in metric tonnes of carbon dioxide equivalent (CO2e) which we converted to tonnes of methane by dividing by IPCC's global warming potential for methane.[35] We then multiplied by 52 to convert tonnes to mcf.[36]

[34] California Air Resources Board. 2017. *Regulation for greenhouse gas emission standards for crude oil and natural gas facilities, Attachment 2*. Available at: https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf.

[35] Using 100-year global warming potential (25) for methane from IPCC Annual Report 4. Chapter 2 table 2.14. Changes in Atmospheric Constituents and in Radiative Forcing. Available at: https://wg1.ipcc.ch/publications/wg1-ar4/ar4-wg1-chapter2.pdf.

[36] Using a calculated tonnes to cubic feet conversion. Available at: https://www.ucsusa.org/sites/default/files/legacy/assets/documents/clean_energy/Infographic-Climate-Risks-of-Natural-Gas-Fugitive-Emissions-Methodology-and-Assumptions.pdf.

APPENDIX C. Emissions Reduction Data by County

Source	Emission Type	CHAVES	COLFAX	EDDY	LEA	MCKINLEY	RIO ARRIBA	ROOSEVELT	SAN JUAN	SANDOVAL	ALL COUNTIES
Abandoned Wells	**CH4 Emissions**	507	0	1,421	2,537	101	406	304	1,116	0	6,394
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	209	0	522	940	0	104	104	313	0	2,192
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Abnormal Emissions	**CH4 Emissions**	723,460	189,384	6,066,805	5,746,067	7,760	376,294	60,897	1,153,228	45,041	14,368,936
	CH4 Reduction	344,601	90,119	2,873,902	2,724,923	3,701	168,064	28,895	541,515	21,448	6,797,168
	VOC Emissions	239,380	4,612	1,871,394	1,721,050	169	40,159	18,336	148,488	4,556	4,048,144
	VOC Reduction	114,051	2,186	886,539	816,288	89	16,726	8,698	69,269	2,186	1,916,032
Associated gas flaring	**CH4 Emissions**	1,103	53	57,712	41,643	0	525	158	735	53	101,980
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	367	0	17,519	12,326	0	105	52	105	0	30,474
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Associated gas venting	**CH4 Emissions**	1,260	158	38,120	25,991	315	1,995	263	15,542	1,523	85,166
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	419	0	12,252	7,644	0	314	105	1,780	157	22,671
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Centrifugal Compressors	**CH4 Emissions**	293	0	2,926	1,873	0	176	59	293	0	5,619
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	114	0	912	570	0	57	0	57	0	1,710
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Combustion Exhaust	**CH4 Emissions**	3,950	1,756	32,293	32,418	63	29,471	251	61,262	3,073	164,536
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	503	251	4,149	4,149	0	3,835	0	7,921	377	21,185
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Dehydrators	**CH4 Emissions**	150	150	1,204	827	0	2,482	0	5,341	75	10,230

Source	Emission Type	CHAVES	COLFAX	EDDY	LEA	MCKINLEY	RIO ARRIBA	ROOSEVELT	SAN JUAN	SANDOVAL	ALL COUNTIES
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	74	0	369	221	0	369	0	812	0	1,845
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Flares	**CH4 Emissions**	1,131	0	16,650	17,593	0	314	63	440	63	36,254
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	378	0	5,356	5,230	0	63	0	63	0	11,089
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Gathering Pipelines	**CH4 Emissions**	10,195	5,622	82,084	86,582	75	77,736	600	98,576	2,474	363,944
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	3,523	1,949	28,485	30,059	0	18,215	225	23,088	600	106,143
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Gathering Station Blowdowns	**CH4 Emissions**	1,426	2,327	37,158	30,702	0	23,270	150	35,281	1,201	131,515
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	522	821	12,834	10,595	0	5,447	75	8,208	298	38,800
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Gathering Stations	**CH4 Emissions**	13,938	22,923	362,165	298,915	141	226,539	1,698	343,700	12,027	1,282,047
	CH4 Reduction	3,861	6,340	100,340	82,819	58	62,763	461	95,211	3,343	355,196
	VOC Emissions	4,811	7,924	125,727	103,794	0	53,064	566	80,516	2,830	379,232
	VOC Reduction	1,325	2,189	34,794	28,746	0	14,690	173	22,294	806	105,017
High-Bleed Pneumatic Controller	**CH4 Emissions**	3,737	113	11,135	14,495	0	7,776	75	9,173	453	46,958
	CH4 Reduction	2,353	78	7,008	9,129	0	4,888	52	5,767	284	29,560
	VOC Emissions	1,289	0	3,526	4,322	0	1,365	38	1,365	38	11,942
	VOC Reduction	810	0	2,222	2,719	0	863	26	863	26	7,528
Intermittent-bleed Pneumatic Controller	**CH4 Emissions**	4,827	815	67,197	42,688	125	108,693	376	161,159	2,445	388,325
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	1,568	0	20,761	12,733	0	21,326	125	27,598	251	84,363
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Leaks	**CH4 Emissions**	22,639	12,361	179,310	184,102	139	163,337	1,250	209,310	5,486	777,935
	CH4 Reduction	14,454	7,884	114,087	117,229	57	103,975	800	133,226	3,485	495,197

Source	Emission Type	CHAVES	COLFAX	EDDY	LEA	MCKINLEY	RIO ARRIBA	ROOSEVELT	SAN JUAN	SANDOVAL	ALL COUNTIES
	VOC Emissions	7,571	278	55,292	55,153	0	30,633	347	32,578	556	182,409
	VOC Reduction	4,808	172	35,262	35,147	0	19,520	229	20,779	343	116,261
Liquids Unloading	CH4 Emissions	675	825	3,074	2,175	150	229,530	75	148,471	1,650	386,625
	CH4 Reduction	378	566	1,888	1,322	0	144,432	0	93,456	1,133	243,175
	VOC Emissions	225	0	976	676	0	47,021	0	25,689	150	74,738
	VOC Reduction	187	0	560	374	0	29,332	0	15,880	187	46,520
Low-bleed Pneumatic Controller	CH4 Emissions	22,688	1,316	54,840	47,570	313	474,630	627	341,761	7,521	951,266
	CH4 Reduction	13,097	760	31,658	27,461	181	273,995	362	197,292	4,342	549,148
	VOC Emissions	7,577	0	17,346	14,152	0	101,570	188	63,309	751	204,893
	VOC Reduction	4,374	0	10,013	8,170	0	58,634	108	36,547	434	118,280
Malfunctioning Pneumatic Controller	CH4 Emissions	29,109	4,126	224,733	160,580	565	652,890	1,357	703,478	12,265	1,789,104
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	9,720	113	69,738	47,754	0	134,503	452	124,500	1,187	387,967
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Oil and Condensate Tanks	CH4 Emissions	3,782	204	40,273	36,900	51	39,660	716	52,641	869	175,095
	CH4 Reduction	2,050	95	22,074	20,214	48	21,692	381	28,843	477	95,875
	VOC Emissions	24,352	1,381	259,687	238,098	358	256,003	4,553	340,059	5,730	1,130,222
	VOC Reduction	13,297	763	142,031	130,258	191	140,029	2,478	186,022	3,146	618,215
Pneumatic Pump	CH4 Emissions	2,260	699	13,881	12,482	0	7,694	161	16,087	215	53,480
	CH4 Reduction	1,552	517	9,682	8,721	0	7,834	74	16,408	222	45,010
	VOC Emissions	752	0	4,513	3,761	0	1,236	54	2,310	0	12,626
	VOC Reduction	503	0	3,091	2,588	0	1,222	0	2,300	0	9,705
Produced Water	CH4 Emissions	1,349	9,970	76,386	112,068	75	3,298	600	19,565	1,274	224,587
	CH4 Reduction	24	174	1,334	1,957	1	58	10	342	22	3,922
	VOC Emissions	74	594	4,526	6,603	0	223	0	1,187	74	13,280
	VOC Reduction	1	10	79	115	0	4	0	21	1	232
Reciprocating Compressors	CH4 Emissions	184	184	1,720	1,167	0	2,274	0	4,854	123	10,507
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	62	0	558	372	0	434	0	806	0	2,233

Source	Emission Type	CHAVES	COLFAX	EDDY	LEA	MCKINLEY	RIO ARRIBA	ROOSEVELT	SAN JUAN	SANDOVAL	ALL COUNTIES
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Well Completions	**CH4 Emissions**	83	0	4,949	4,810	0	222	56	1,668	250	12,038
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	27	0	1,504	1,395	0	27	27	246	27	3,255
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Well Testing	**CH4 Emissions**	2	0	20	20	0	16	0	20	0	79
	CH4 Reduction	0	0	0	0	0	0	0	0	0	0
	VOC Emissions	0	0	6	6	0	2	0	2	0	16
	VOC Reduction	0	0	0	0	0	0	0	0	0	0
Well Workovers	**CH4 Emissions**	102	0	918	918	0	714	0	918	0	3,572
	CH4 Reduction	63	0	568	568	0	442	0	568	0	2,208
	VOC Emissions	0	0	268	268	0	89	0	89	0	714
	VOC Reduction	0	0	166	166	0	55	0	55	0	442

PATHWAYS FOR ALTERNATIVE COMPLIANCE

A Framework to Advance Innovation, Environmental Protection, and Prosperity

Environmental Defense Fund &
Environmental Council of the States
Shale Gas Caucus

April 2019

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Acknowledgements
Lucy Cheadle, Carrie Crumpton, Joe Dawley, Kate Fay, Dave Glatt, Michael Hopkins, Ying Hsu, Matthew Kolesar, Kathleen Kozawa, Leah Martland, Patrick McDonnell, Brad Morello, Jim Nolan, Jim Nyarady, Todd Parfitt, Lia Parisien, Drew Pomerantz, Arvind Ravikumar, Dirk Richter, Martha Rudolph, Tim Taylor, Erin Tullos, Dan Zimmerle

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Contents

Executive summary

Leak detection and repair is a pressing concern for the oil and gas industry, as leaks profoundly undermine the industry's claim for part of the future energy mix. Companies are concerned about lost product, current and future regulations, and the impact on their reputations. State and federal authorities worry about damage to public health, climate change implications, and lost revenue. Innovators see a potential new market in solving all of these problems. Unfortunately, although the past couple of years have shown significant creativity in leak detection and repair strategies, many new technologies have stalled just past the pilot stage.

The challenge

The increasing pace of technological change poses both a challenge and an opportunity.

- Innovators and industry have said that lack of a pathway for approval of new methods as compliance tools for leak detection and repair is the single biggest barrier to investing in and deploying new solutions. Without a pathway for approval of new methods, innovation can slow or even stop once a regulatory mandate is established, with the result that best practice is frozen. For potential entrepreneurs serving the oil and gas industry, demonstrating approval as a compliance device, or at least a pathway to approval, is essential to securing the scarce resources that turn an idea into a commercial offering. A nonexistent, multi-year, or uncertain approval process may lock in legacy technologies, and inhibit operators from lowering the cost of compliance over time.

- For regulators, the broad and constantly changing array of potential new solutions can be daunting. They may question the quality of the data put forward by innovators, and lack the capacity to evaluate complex technologies and methods. Each regulator would need to match its ideal policy outcome with its legal authority, and engage other stakeholders such as local implementing and enforcing agencies, as appropriate.

The opportunity

Resolving these questions is necessary in order to to unleash the potential of innovation to achieve environmental protection and advance economic prosperity. There is uncommonly strong agreement among environmentalists, regulators, innovators, and operators that alternative compliance pathways are needed. Many new and different leak detection and repair solutions are already advertising themselves, and the pipeline of future innovation could be strong. All agree about the need to achieve environmental protection and economic growth at the lowest possible cost, because:

- Better technologies can achieve regulatory goals faster and at lower cost, and enable easier monitoring.
- Operators can lower their cost of compliance, report more effectively, and earn greater flexibility.
- Innovators can bring the best of the sensor and data revolution to solve environmental and business challenges.

This is a three-part report. The research questions were determined in collaboration with the Environmental Council of the States Shale Gas Caucus, and industry representatives, technology innovators, environmentalists, and federal regulators.

Lessons learned

We review applicable policies in six states and a rule promulgated by the U.S. Environmental Protection Agency (EPA). Colorado and EPA are the only jurisdictions with an express and existing pathway for the approval of alternatives. The experience with these constructive attempts offers lessons learned for those and other jurisdictions.

- The first and most important question raised by all stakeholders was how to demonstrate equivalency between the regulatory mandate and new methodologies. It is difficult to assess new techniques against the percentage reductions in emissions projected as the impact of current best practice. This pronounced difficulty is due to the shift from close-range technologies used on a fixed schedule to continuous or mobile approaches deployed over broader space and time.
- The process for approvals, even with recent revisions, is still considered too uncertain and slow by some. To promote confidence in the system, concerns about privacy need to be balanced with the goals of transparency and opportunity for public input.
- The consequences of an approval, for example on obligations to

inspect and report, can make a significant difference in the value of an approval, and therefore the incentive for operators and innovators to create new solutions in the first place. Stakeholders questioned how broadly an approval extends—one site at one operator, multiple sites of one operator, or even multiple similar sites and sources from different operators.

- Demand for innovation is also influenced by whether there is an off-ramp for the old approach, once a new methodology is approved, and whether new reporting and monitoring strategies may adapt to take advantage of technology capabilities. Many new digital technologies could allow operators to report more easily and more precisely on their own emissions, and give regulators faster and easier insights.
- Finally, the fact that an approval in one state may not advance an application in another jurisdiction dramatically reduces the potential market for innovation and discourages investment.

Evaluation Framework

We define a mathematical, technology-neutral framework for comparing emission reductions of different practices. It is important to note that the framework, and this report in general, concern methodologies, not technologies. The approach that reduces the most emissions in a given circumstance may combine different technologies used at different times and for different purposes. Even for one technology, the mitigation actions that the information triggers determine the emissions impact, not the technology specifications.

Recommendations

This evaluation framework can be applied in a regulatory process and as a tool to facilitate interjurisdictional collaboration:

- States and federal agencies can adopt the same model for evaluation of equivalency in leak detection and repair methodologies. Agencies can make their default approvable ranges for critical model inputs public, and even if they have different ranges, this still gives innovators and operators clearer goalposts for performance.
- A transparent and rapid process is also essential to encourage innovation and maintain public confidence.
- Allowing approved methodologies to be used as broadly as scientifically justified, providing an off-ramp for the status quo best practice, and allowing modified reporting and monitoring would all encourage innovation without sacrificing environmental impact.
- Finally, jurisdictions can collaborate to take advantage of the work done in prior assessments, increasing the potential market for new solutions and therefore encouraging investment in better leak detection and repair.

At heart, a regulatory framework that encourages innovation takes advantage of the fact that technology makes it faster and cheaper to understand the world, and creative methods using these new technologies can enable better detection, mitigation, and monitoring to reduce waste and protect the environment.

Regulatory context

EPA and Colorado have promulgated rules that allow for approval of novel leak detection methods. Since these two rules form the basis of established best practice, and experience with those rules has revealed opportunities for improvement, we summarize these rules in detail below. Other states with leak detection and repair requirements on oil and gas are also summarized.

EPA

In 2016 EPA finalized a rule that requires broad reductions in volatile organic compounds (VOCs) and methane from a suite of oil and gas equipment.[1] A key element of this rule is a requirement that oil and gas operators inspect for leaks at well sites, gas processing plants, and compressor stations. This "fugitive emissions monitoring" provision requires the use of either an optical gas imaging camera (OGI) or a Method 21 device.[2] Alternatively, owners or operators of well sites and compressors,[3] or, in the case of gas processing plants,[4] manufacturers, may apply to EPA for approval to use another means to conduct these inspections.

EPA's fugitive emissions monitoring requirement is a work practice standard. The Clean Air Act (CAA) authorizes EPA to establish work practice standards instead of standards of performance where "it is not feasible to prescribe or enforce a standard of performance."[5] The CAA further authorizes EPA to approve of alternative work practice standards provided that such standards "will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved" under the required work practice standard.[6] Accordingly, any alternative method for

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[1] Envt'l Protection Agency, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35824, 35861 (June 3, 2016) (final rule).
[2] 40 C.F.R. §§ 60.5397a(c)(2).
[3] 40 C.F.R. §§ 60.5398a(c), 60.5402a(c).
[4] Id. at § 60.5402a(c).
[5] 42 U.S.C. § 7411(h)(1).
[6] 42 U.S.C. § 7411(h)(3).

conducting fugitive emissions monitoring must achieve at least equivalent emissions reductions as inspections conducted using OGI or a Method 21 device.

Per EPA's 2016 rule, operators wishing to use an alternative fugitive emissions monitoring method must provide detailed information in order to demonstrate that the alternative qualifies as an alternative work practice standard.

First, the applicant must collect, verify, and submit 12 months of test data in its application.[7] This is the information upon which EPA relies in order to determine equivalency. In addition, the applicant must provide detailed information related to the alternative method. This information includes, but is not limited to, a description of the technology or process,[8] initial and ongoing quality assurance/quality control measures,[9] field data verifying viability and detection capabilities of the technology or process,[10] operation and maintenance procedures,[11] restrictions for using the technology or process,[12] and initial and continuous compliance procedures, including recordkeeping and reporting.[13]

All applications for alternative fugitive emissions monitoring are subject to public notice, hearing and comment.[14] As of August 2018, no applications had been made public. The rule does not provide a deadline by which EPA must publish an application for comment or make a final determination. In the final rule, EPA noted that it "intends" to publish a complete application within six months of receipt[15] and that it "intends" to make a final determination within six months after the the public comment period closes.[16] EPA's final determination[17] is published in the Federal Register along with the grounds for the determination. EPA may attach conditions of approval to an alternative work practice standard as necessary to ensure it meets the requirements of the rule and the CAA.[18]

Colorado

In 2014, Colorado became the first U.S. jurisdiction to promulgate a rule requiring comprehensive and robust reductions in methane from a suite of oil and gas equipment and facilities.[19] A hallmark provision of this rule is the requirement that operators inspect for leaks at various intervals, including quarterly and monthly.[20] The inspection interval is tied to production capability; larger-producing sites are subject to more frequent inspections. Per the rule, operators may use either an infrared camera, Method 21, or an alternative approved instrument monitoring method (AIMM) or program (alternative AIMM).[21] The 2014 alternative AIMM provision applied to well production

[7] 40 C.F.R. at §§ 60.5398a(d)(1), 60.5402a(d)(1).
[8] Id. at §§ 60.5398a(d)(1)(i), 60.5402a(d)(2)(i).
[9] Id. at §§ 60.5398a(d)(1)(v), 60.5402a(d)(2)(v).
[10] Id. at §§ 60.5398a(d)(1)(vii), 60.5402a(d)(2)(vii).
[11] Id. at §§ 60.5398a(d)(1)(xi), 60.5402a(d)(2).
[12] Id. at §§ 60.5398a(d)(1)(x), 60.5402a(d)(2)(x).
[13] Id. at §§ 60.5398a(d)(1)(xii), 60.5402a(d)(3).
[14] Id. at § 60.5398a(b), (e); § 60.5402a(b); 81 Fed. Reg. at 35861.
[15] Id. at § 60.5398a(b), (e); § 60.5402a(b); 81 Fed. Reg. at 35851.
[16] Id. at § 60.5398a(e); 81 Fed. Reg. at 35861.
[17] Id.
[18] Id. at § 60.5398a(f)(2).
[19] CDPHE, Alternative AIMM Guidance and Procedures, p. 1 (May 31, 2018) (accessible at https://drive.google.com/file/d/1reFIFX_DVl_Wcu82853NNekmhjOtljui/view); see generally AQCC Reg. 7.
[20] AQCC Reg. 7, §§ XVII.F.3.c, XVII.F.4.b, XVIIIF.2.a, XVIII.F.2.b.
[21] AQCC Reg. 7, § XVII.A.2.

facilities and compressor stations in the gathering and boosting segment of the natural gas supply chain in the state. Owners or operators who opt to use a continuous emission monitoring system may apply to the Air Pollution Control Division (Division) for approval of a streamlined inspection, recordkeeping, and reporting program.[22]

While the 2014 rule allowed for the use of alternative AIMM, the rule provided no criteria to guide the approval process. Rather, the Division provided information related to the approval process, including the type of information applicants wishing to use alternative AIMM must supply to the Division, in a guidance document.

In terms of approval criteria, Colorado's alternative AIMM rule requires that an alternative AIMM be able to demonstrate that it is capable of achieving emission reductions that are at least as effective as the emissions reduction achieved using an infrared (IR) camera or EPA Reference Method 21.[23] In addition, the proposed alternative must be commercially available.[24] 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 of for other applications or by other regulators, and any modeling results or test data.[25] Applicants must describe where they propose to use the alternative method. Information about weather may be relevant to any limitations or restrictions in use of the alternative and must be provided if this is the case.

Colorado allows manufacturers of alternative AIMM as well as operators to apply to gain approval for an alternative AIMM. Once approved, an AIMM may be used by any operator in Colorado to comply with well production facility and compressor station LDAR inspections, and operators may cease using the prior work practice. In addition, approved AIMM may be used to conduct inspections of pneumatic controllers in the Denver nonattainment area.[26] Since 2014 Colorado has approved two alternative AIMM: the Pixel Velocity Automated Hydrocarbon Leak Detection System and the Rebellion Photonics Gas Cloud Imager.[27] Pixel submitted its application for approval of its continuous emission monitoring system on May 31, 2016. After it had email and phone conversations and received supplemental information, the Division approved Pixel's application slightly under one year later, on May 17, 2017. The Division attached nine conditions of approval, including that an owner or operator wishing to use Pixel's monitoring system may apply for a streamlined recordkeeping and reporting program.[28]

In 2017 Colorado made revisions to its state implementation plan (SIP) for ozone. The CAA requires that SIPs and SIP elements be subject to EPA approval and public notice and comment.[29] When Colorado added the alternative AIMM provision to its SIP, it made the alternative AIMM federally enforceable. Accordingly, applications to use an alternative AIMM in the Denver ozone nonattainment area are subject to public notice and comment and an EPA approval process in addition to approval by the Division.[30] Due to stakeholder concerns about potential delays in EPA approval, the rule specifies that the Division will consider EPA inaction on an application after six months to constitute approval.[31] Applicants wishing to use an alternative AIMM outside of the ozone nonattainment area do not need to comply with the new notice and comment procedures, nor obtain EPA approval. The same approval criteria and informational requirements apply to applicants wishing to use an alternative AIMM in the ozone nonattainment areas and to those wishing to use an alternative AIMM outside of the nonattainment area.

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[22] Id.
[23] Id. at § 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_DVI_Wcu82853NNekmhjOtljui/view).
[24] Id. at § XII.L.8.a(ii)(B); Alternative AIMM Guidance and Procedures, p. 2.
[25] Id. at § XII.L.8.a(i); Alternative AIMM Guidance and Procedures, p. 1.
[26] Alternative AIMM Guidance and Procedures, p. 1.
[27] Letter from Jennifer Mattox, CDPHE, to Robert Kester, Rebellion Photonics (Jan. 15, 2015) (accessible at https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMapprovalRebellion.pdf); Letter from Jennifer Mattox, CDPHE, to Heather Grisham, Pixel Velocity (May 17, 2017) (accessible at https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance2-AIMMapproval_Pixel_Velocity.pdf).
[28] Letter from Jennifer Mattox to Heather Grisham.
[29] 42 U.S.C. § 7410.
[30] AQCC Reg. 7, § XII.L.8.
[31] Id. at § XII.L.8.a.(v).[32] PADEP, Gen. Plan Approval and/or Gen. Operating Permit BAQ-GPA/GP-5 (March 2018) (accessible at http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=12967&DocName=FINAL%20DRAFT%20GP-5%20-%20NATURAL%20GAS%20COMPRES SION%20STATIONS%2C%20PROCESSING%20PLANTS%2C%20AND%20TRANSMISSION%20STATIONS.PDF%20%20%3Cspan%20 style%3D%22color%3Ablue%3B%22%3E%3C%2Fspan%3E); PDEP, Gen. Plan Approval and/or Gen. Operating Permit BAQ-GPA/GP-5A (June 2018) (accessible 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%20 GENERAL%20PLAN%20APPROVAL%20AND/OR%20GENERAL%20OPERATING%20PERMIT.PDF%20%20%3Cspan%20style%3D%22color:blue%3b%22%3E%28NEW%29%3C/span%3E).

Pennsylvania

The Pennsylvania Department of Environmental Protection (PADEP) recently finalized two General Permits that require operators to reduce methane, VOC, and hazardous air pollutant emissions from a suite of equipment found at well sites, pigging stations, gas processing plants, and compressor stations.[32] A key element of these permits is a requirement that operators inspect for leaks on a quarterly basis. Operators of well sites and pigging operations may reduce the inspection frequency based on the percentage of leaking components detected over time. Operators may use an OGI camera, EPA Method 21, or an approved alternative.[33]

Any operator wishing to use the General Permits to authorize construction of a well site, compressor station, or gas processing may apply to use an alternative approved device for the purposes of conducting leak detection and repair (LDAR) inspections. However, it is not clear what the approval process would look like. Unlike Colorado and EPA, Pennsylvania has yet to develop a clear approval pathway; there is no rule governing the approval of alternative technologies or methods and PADEP has not issued any guidance materials. PADEP is currently working on developing guidance materials to provide criteria and informational requirements that will govern the alternative LDAR methods and technology approval process for new sources using the General Permits.

PADEP is also developing a separate rule that will require emission reductions from existing sources, including sources of fugitive emissions.[34] PADEP has broad authority to allow for the use of alternative LDAR methodologies. Pursuant to the Air Pollution Control Act, PADEP can "require the owner or operator of any air contamination source to install, use and maintain such air contaminant monitoring equipment or methods as the department may reasonably prescribe" and to "require the owner or operator of any air contamination source to sample the emissions thereof in accordance with such methods and procedures and at such locations and intervals of time as the department may reasonably prescribe and to provide the department with the results thereof."[35] Accordingly, when PADEP proposes a rule to require LDAR inspections at existing sources, it may include a robust compliance approval pathway for emerging methodologies.

Wyoming

Wyoming requires operators to inspect for leaks of VOCs on a quarterly basis at new and existing well sites in the Upper Green River Basin (UGRB) ozone nonattainment area if fugitive VOC emissions are equal to or greater than 4 TPY; otherwise semiannual monitoring is required. Semiannual monitoring is required for new and modified well sites in

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[33] Gen. Plan Approval and/or Gen. Operating Permit BAQ-GPA/GP-5, p. 17; Gen. Plan Approval and/or Gen. Operating Permit BAQ-GPA/GP-5A, p. 18.

[34] PADEP, A Pa. Framework of Actions for Methane Reductions from the Oil and Gas Sector, p. 3 (Jan. 19, 2016) (accessible at http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Methane/DEP%20Methane%20Strategy%201-19-2016%20PDF.pdf).

[35] 35 P.S. § 4004(5),(6).

all other areas of the state. Quarterly inspections are also required for existing compressor stations in the basin, and for new and modified compressor stations in the basin and in all other areas of the state.[36] Operators of existing sites in the UGRB may use either OGI, Method 21, audio-visual-olfactory (AVO) inspections, other instrument-based technologies, or some combination of the above.[37] Operators of new and modified sites in the UGRB and the rest of the state are required to use optical gas imaging, Method 21, or an EPA-approved alternative method.[38]

In 2018, Wyoming updated its Oil and Gas Permitting Guidance to reflect that Wyoming will allow use of EPA-approved alternative fugitive emissions monitoring methods. Accordingly, applicants wishing to use an alternative method must demonstrate that it is an EPA-approved method. The Wyoming Department of Environmental Quality has yet to receive an application to use any alternative fugitive emissions monitoring technology or methods.[39]

Ohio

Ohio requires operators to conduct LDAR inspections at well sites and compressor stations. In Ohio, all control requirements must demonstrate Best Available Technology (BAT).[40] The Ohio EPA has determined that LDAR conducted with either a Forward Looking Infrared Camera or Method 21 is the current BAT. Pursuant to two General Permits, operators must use one of these two methods.[41] Because neither General Permit includes a provision allowing for the use of alternatives, operators must apply for an individual permit for each facility where the operator wishes to use the alternative method. An alternative LDAR would need to demonstrate that it constitutes BAT.[42]

A request to use an alternative LDAR as part of an individual permit application is noticed.[43] The public has an opportunity to request a hearing on the permit and may submit comments at the hearing or in writing.[44] The issuance or denial of a permit is a final agency action and can be appealed.[45] Ohio has yet to receive a request to use a non-standard LDAR approach.

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[36] Wyo. Air Quality Standards & Regs. Ch. 8, § 6(g)(i); WDEQ, Oil and Gas Prod. Facilities Chap. 6, Sec. 2 Permitting Guidance, pgs. 13, 16, 22 (December 2018) (accessible at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf; see also OOOOa as published in 81 Fed. Reg. 35824-35941 (June 3, 2016).

[37] Wyo. Air Quality Standards & Regs, Ch. 8, § 6(g)(i)

[38] WDEQ, Oil and Gas Prod. Facilities, Chap. 6, Sec 2, Permitting Guidance, pgs 13, 16, 22; WDEQ, Response to Comments, pg 5 (Response 11) and pg 8 (Response 1) (December 2018) (accessible at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018%20Response%20to%20Comments.pdf

[39] Email correspondence from Josh Nall, NSR Permitting Supervisor, Wyo. Dept. of Envt'l Quality (Apr. 30, 2018).

[40] OAC 3745-31-05(A)(3).

[41] Ohio EPA, General Permit 12.1 Template, pp. 42-46 (accessible at https://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf); Ohio EPA, General Permit 18.1 Template, p. 5 (accessible at http://epa.ohio.gov/Portals/27/genpermit/GP18.1_TVF20170223.pdf).

[42] Id. (for permit approval, facility must employ BAT); See also Ohio. R.C. § 3704.03(T)(Requiring new and modified sources install BAT, with some exceptions).

[43] OAC 3745-31-29(D), 3745-31-06(H); Email correspondence from Mike Hopkins.

[44] Id. at 3745-31-06(H).

[45] Id. at 3745-31-29(D)(1), (D)(4); Email correspondence from Mike Hopkins.

For Ohio to facilitate alternative LDAR methods at new sources, it would need to revise its General Permits to specifically allow for the use of alternative methods. This would require a public notice and comment period, but not a rulemaking.[46] In order to allow for the use of alternative methods at existing sources, Ohio would need to promulgate a new rule. In practice, Ohio would also need to enable applications that encompass more than one facility.

California

The California Air Resources Board (CARB) finalized a comprehensive rule in 2017 that regulates methane from a suite of equipment at new and existing, upstream and midstream facilities.[47] The rule includes an LDAR provision that requires operators to conduct quarterly inspections at well sites, gas processing plants, natural gas storage facilities, and compressor stations using Method 21.[48]

While the rule does not allow for the use of alternative methods to conduct LDAR inspections at this time, CARB has acknowledged that it may revise its rule in the future to do so. Specifically, in response to comments suggesting that CARB allow for the use of alternatives, CARB noted:

> [C]ARB staff has also been in close contact with a number of instrument manufacturers, some of which have been developing newer instruments or newer types of technologies to speed up testing or provide for automated measurements. Throughout implementation of the regulation, staff plans to continue working with instrument manufacturers and perform studies to evaluate the effectiveness of these newer instruments or technologies, and to determine how they compare with Method 21. Given the results of these studies, staff may find a need to make future modifications to the regulation to allow for the use of these instruments.[49]

We identified no statutory barriers to CARB including a provision in its rule that allows for the approval of alternative LDAR technologies. Indeed, such a provision would be in line with the legislature's intent to "invest in the development of innovative and pioneering technologies"[50] in order to help California meet its GHG reduction goals and consistent with California's demonstrated leadership in implementing a suite of measures, including regulations and market-based compliance measures, to tackle climate change.

A change to the rule allowing for the use of alternative LDAR methods in addition to Method 21 would require CARB approval and be subject to public notice and comment.[51]

In addition, in order to ensure early detection of large leaks, such as the one that occurred from the Aliso Canyon storage facility in 2016, owners and operators of underground natural gas storage facilities must install continuous air monitoring to measure upwind and downwind ambient concentrations of methane and conduct daily screenings or continuous leak screenings at each injection/withdrawal wellhead assembly and attached pipelines.[52] Daily screenings may be conducted using Method 21, OGI, or "other natural gas leak screening instruments approved by the [C]ARB Executive Officer."[53] These daily screenings are separate from the quarterly LDAR Method 21 inspections, as screenings are limited to injection/withdrawal wellhead assembly and attached pipelines and are intended to "pinpoint a blowout or large leak at the well head assemblies," whereas LDAR inspections apply to other equipment at a facility "such as separator and tank systems, natural gas compressors, and other piping systems or components."[54] The daily or continuous monitoring requirement specifically allows for alternative compliance applications, although no specific guidance has been issued.

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[46] Id. at 3745-31-06(H).
[47] 17 C.C.R. § 95665 et seq. (2017).
[48] Id. at § 95669(g).
[49] Id. at 106.
[50] West's Ann.Cal.Health & Safety Code § 38501(e).
[51] West's Ann.Cal.Health & Safety Code § 38500 et seq.
[52] Id. at § 95668(h)(5)(A), (h)(5)(B).
[53] Id. at § 95668(h).
[54] State of Cal. Air Res. Bd., Final Stmt. of Reasons, Reg. for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, p. 76 (May 2017) (accessible at https://www.arb.ca.gov/regact/2016/oilandgas2016/ogfsor.pdf).

Demonstrating equivalency over space and time

The primary question raised by stakeholders regarding approval of alternative methodologies concerned how to demonstrate equivalency. As of now, the question can only be asked of the Colorado and EPA rules, since these are the only two with clear and detailed approval pathways. The risk for regulators is that uncertainty regarding how to determine equivalency prompts the reviewing agency to reject an application, or even dissuade applicants in the first place. The risk for an operator or innovator is both that the proposed solution will not be approved, and that it will be approved, but the standards for approval will be so lax that the proposed solution will be underbid by less scrupulous competitors. This risk essentially dissuades innovators and operators from investing in the development of new solutions.

"The first step in determining equivalency is to understand: equivalent to what?"

The first step in determining equivalency is to understand: equivalent to what? In the final technical support document accompanying the adoption of its LDAR requirements, EPA determined that semi-annual inspections using OGI will reduce leaks by 60%.[55] For compressor stations, EPA determined an 80% reduction.[56] In coming to this conclusion, EPA considered the required inspection frequency, size of leaks detectable using both types of technology, and anticipated emissions reductions associated with repairs.

Colorado undertook essentially the same methodology in estimating anticipated emission reductions associated with its tiered LDAR requirements. The Division estimated that monthly inspections can reduce leak emissions by 80%, quarterly inspections can reduce such emissions by 60%, and semi-annual inspections can reduce emissions by 40%.[57] The Division assumed that Method 21 inspections were equally as effective in reducing leaks as IR camera inspections.[58]

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[55] U.S. EPA, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Background Tech. Supp. Doc. for the Final NSPS, 40 CFR Part 60, subpart OOOOa, p. 41 (May 2016) (accessible at https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631).

[56] TSD at p. 49.

[57] Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6 and 7 (February 11, 2014) (accessible at file:///C:/Users/anowlan/Downloads/RegulatoryAnalysisAttachment2013-01217.PDF)

[58] Id.

These statements of efficacy of OGI and Method 21 form the most detailed information available to operators or innovators interested in demonstrating the effectiveness of their proposed alternative methodologies. Prospective applicants must aim to demonstrate equivalent or greater reductions—40%, 60%, or 80%, according to the frequency and the target facility of the LDAR they seek to replace.

Feedback from stakeholders indicates that it is very difficult to assess leak detection methodologies and arrive at a metric of reductions required by these percentage targets. Public data are lacking about the size and timing of leaks to be expected for different kind of facilities or equipment—the base case scenario that any alternative would be compared against. It is also currently expensive and onerous to quantify methane emissions in the field. As a result, both the status quo and proposed impact of new methodologies are difficult to assess and compare.

For operators wishing to obtain approval for an alternative AIMM in Colorado, demonstrating equivalency appears even less clear. Colorado approvals apply to any facility, and the type of LDAR program required for each facility differs depending on type and production capability (or, in the case of compressor stations, capacity). Accordingly, an applicant wishing to obtain approval for an alternative AIMM may not know if the alternative must demonstrate a 40% or a 60% reduction in emissions. In addition, as Colorado and EPA estimate different emissions reductions from the same LDAR frequency, equivalency becomes even more complex.

The differences in the types of leak inspection methods being developed and the manner in which they can be deployed to identify leaks poses a challenge to the goal of developing and evaluating alternative LDAR methods. EPA and state LDAR requirements all prescribe the use of certain leak inspection technologies (e.g., infrared cameras) and the manner in which such technologies must be used (e.g., four times a year at one facility). The effectiveness of these LDAR requirements in reducing emissions is predicated on assumptions regarding the efficacy of the combination of the technology and the frequency of inspections, as well as assumptions regarding the efficacy of repairs. Emerging LDAR methods often are predicated on different types of technologies (e.g., lasers rather than optical gas imaging devices) and are deployed in a different manner (e.g., continuously at one location, or over broad geographies at great frequency). This poses a challenge to regulators attempting to compare anticipated emission reductions from very different types of technologies and leak detection methods.

Most traditional leak detection methods involve very close-range, individual evaluations of particular equipment, repeated on a fixed schedule. New continuous and mobile solutions cover larger geographic areas or are deployed over a longer period of time, or both. For example, mobile-based technologies affixed to a plane or vehicle are capable of inspecting multiple facilities a day, whereas a human holding a handheld device may only be able to get to one or two facilities per day. Continuous monitors can prompt a repair when a leak is detected, which nearly eliminates the time a leak continues unabated, and therefore dramatically reduces the associated emissions. The best methods likely combine instruments, for example by using an instrument with a high detection threshold to prompt a survey by a more sensitive handheld instrument. Independent test data used as inputs for sophisticated modeling can enable comparison of alternative methodologies that take advantage of the capabilities of new technologies and ways to combine them over space and time. However, regulators and operators both point to the time and expertise required to evaluate potential methodologies and model emissions reductions; little staff capacity exists for these new and important roles.

Process concerns and barriers

A number of stakeholders have raised questions regarding procedural elements of the approval of alternative leak detection methods. Questions of particular concern involve how much of an application will be public and whether regulators can assist applicants. The ideal balance here combines protection of business information to the minimum extent necessary, with transparency and opportunities for public comment, to maintain confidence in the system and ensure the environmental protection goals are being met.

In Colorado, whether an application to use an alternative LDAR approach is subject to public notice and comment depends on whether or not the alternative will be used solely outside the ozone nonattainment area. Alternatives that will be used solely outside the ozone nonattainment area are not made public.[59] By contrast, applications to use an alternative LDAR method in the ozone nonattainment area are subject to notice and comment procedures.[60] For such applications, all of the application, the Colorado Air Pollution Control Division's preliminary analysis, and the draft permit to be filed are public and subject to public comment.[61] Applicants can request that portions of an application remain confidential under the Division's confidential business information policy. Applicants must mark any information as "confidential business information." Information so marked will not be posted publicly on the Division's website.[62] The Colorado rule does not contain appeal procedures, so it is unclear whether or not a CDPHE or EPA approval decision, or failure to make a decision, may be appealed.

Stakeholders have also requested information regarding whether regulators interact with potential applicants. The Division can and does interact with potential applicants. In the case of the approval of the Pixel LDS, the Division corresponded with the applicant via conference call and e-mail four times following the applicant's original application.[63]

EPA also makes applications for alternative work practices public. EPA must publish the application, accept public comment, and publish its final determination including reasons for the denial or approval. EPA's decision with respect to an application to use an alternative work practice standard constitutes final agency action.[64] Accordingly, pursuant to the CAA, applicants may appeal the decision.[65]

Use of an approved method

The question of how broadly an approved alternative may be employed has significant implications for the market for that alternative, and consequently, the investment an innovator or operator will likely make in developing an alternative. On the other hand, a regulator is concerned with ensuring that an alternative is employed only in circumstances where the data support that equivalent reductions can be expected. For states that operate via permits at each facility, there may be structural limitations to approving an alternative methodology for multiple operators or facilities in one decision.

In Colorado, the approval is for a technology or a method — not for an individual operator or facility.[66] Accordingly, an approved method can be used by any operator of a non-Title V facility. Operators of Title V facilities must be specified within each Title V operating permit, and an operator of a Title V facility must first request a modification or revision to its permit before being able to use an alternative AIMM.[67]

[59] Alternative AIMM Guidance and Procedures, p. 7.
[60] AQCC Reg. § 7.XII.L.8.a(iv).
[61] AQCC Reg. § 3 Part B.III.C.4.
[62] CDPHE, Alternative AIMM Public Notices (accessible at https://www.colorado.gov/pacific/cdphe/air/alternative-aimm-public-notices).
[63] Letter from Jennifer Mattox to Heather Grisham, p. 1.
[64] 42 U.S.C. § 7607(b)(1).
[65] Id.
[66] Alternative AIMM Guidance and Procedures, p. 8.
[67] CDPHE, Approved Instrument Monitoring Method (AIMM) for Oil and Gas (accessible at https://www.colorado.gov/pacific/cdphe/AIMM).

Under the EPA rule, an approval of an alternative means of emissions limitation constitutes a required work practice, equipment, design or operational standard within the meaning of 42 U.S.C. 7411(h).[68] The 111h standards, once adopted, are treated as standards of performance.[69] Standards of performance apply to sources, not individual facilities.[70] Accordingly, although not explicitly stated it would appear that once EPA approves an alternative it may be used at any source, not just by the owner or operator of a particular facility or group of facilities that applied.

Consequences for recordkeeping, reporting, and monitoring

Many stakeholders indicated that new technologies can change the way recordkeeping and reporting is done. Many new technologies send data electronically to analytics databases and dashboards. A significant area of shared interest would be to take advantage of capabilities of new technologies to reduce the recordkeeping and reporting burden on operators and improve transparency to regulators. For example, in Colorado, approved continuous monitoring AIMMs are eligible for approval of a streamlined inspection, recordkeeping, and reporting program.[71]

Some stakeholders have expressed concern regarding how a regulator would enforce an alternative LDAR provision. For example, during the rule development in California, CARB considered allowing operators to use optical gas imaging cameras in addition to Method 21 devices. Local air districts, which are responsible for implementing the regulation, expressed concern regarding enforcement of non-quantitative leak detection methods. Local air districts currently have rules requiring the inspection and repair of VOC leaks using Method 21 only. Concerns about enforceability ultimately resulted in California not including a pathway for alternative compliance methodologies, despite stakeholder requests that it do so.

Regulator and implementing agency (if different from the regulator) comfort with the enforceability of new methodologies is therefore an important aspect to consider when advocating for a rule that allows alternative applications, and in the context of individual applications when the rules permit them. This is another area where the capabilities of new technologies, deployed creatively, could be used to build consensus between operators, innovators, and regulators. For example, ongoing monitoring or verification, such as continuous monitoring at a representative subset of facilities, could give both regulators and operators much-needed data to demonstrate that new methodologies are working and offer opportunities for improvements if results do not live up to expectations.

Reciprocity with other jurisdictions

Given the time and effort required for approval in one jurisdiction, and the fact that oil and gas operations are spread across the country and around the world, reciprocity between jurisdictions offers a powerful tool to build the market, encourage innovation, and reduce the burden on any one regulator. Already in Colorado, approval by other jurisdictions or use for other purposes (such as pipeline leak monitoring) is a factor the Division considers when reviewing alternative AIMM applications.[72] However, approval by other jurisdictions or use for other purposes is not per se grounds for approval. Other state regulators also indicated that they would consider approvals granted by other regulators as relevant information when assessing alternative LDAR methods to be used for compliance with state rules. The technology comparison framework below, and recommendations concerning a shared model, are intended to facilitate this interjurisdictional collaboration.

[68] 40 C.F.R. § 60.5398a(f)(2).
[69] 42 U.S.C. § 7411 (h)(5) (providing that "[A]ny design, equipment, work practice, or operational standard, or any combination thereof, described in this subsection shall be treated as a standard of performance for purposes of the provisions of this chapter (other than the provisions of subsection (a) of this section and this subsection.")
[70] Id. at § 7411(b)(1)(B)(providing that standards of performance for new sources within such category).
[71] Id. at §§ XII.B.3, XVII.A.2.
[72] Id. at §§ XII.B.3, XVII.A.2.

Technology comparison framework

In this section, we describe a technology comparison framework that provides a clear, transparent, and scientifically rigorous approach to compare diverse leak detection methods based on their estimated emission reductions. In summary, the framework uses a combination of empirical data and standardized assumptions to model the impact of leak detection methods and associated repair protocols on aggregate emissions from a population of facilities. The framework adheres to several principles:

1. **Technologies are assessed as part of an LDAR protocol.** Leak detection technologies do not reduce emissions alone but instead provide stakeholders with data that informs mitigation. In order to estimate emission reductions, it is necessary to determine both which emission sources are detected and the mitigation actions that are triggered when emissions are detected. For example, some detected emissions may be intentional, vented sources or judged too small to cost-effectively repair. The evaluation process must include a clear protocol that describes how data provided by the technology lead to actions to mitigate those emissions, including decisions about which sources to repair and the time required between detection and mitigation.

2. **Emission reductions are determined in aggregate.** O&G emission sources have highly skewed distributions at both the component and site level, with the top 5% highest emitting sources typically accounting for over half of the total emissions from that source.[73] Many of these high emitting sources are

"Leak detection technologies do not reduce emissions alone but instead provide stakeholders with data that informs mitigation."

[73] Adam Brandt, Garvin Heath, and Daniel Cooley, 50 Environ. Sci. Technol. 22, 12512-12520 (2016).

stochastic,[74] and therefore leak detection technologies likely will be deployed across a population of sites that can include a relatively small but shifting subpopulation of super-emitters. A consequence of this skewed distribution is that technologies with higher detection limits may yield equivalent or greater emission reductions than low detection limit technologies if used in a fashion that leads to quicker detection and mitigation of high emitting sources. However, this equivalency only holds if emission reductions are compared in the aggregate, such as the annual emission reductions from all of an operator's well pads in a basin. A few sites will likely account for the bulk of emissions, but it is impossible (thus far) to predict in advance where super-emitters will occur. As a result, a regulator must assess a method over a group of sites and a period of time. Otherwise, high detection limit, fast-response technologies will appear less effective at relatively low-emission sites but much more effective in the super-emitter sub-population compared to a lower detection limit, low-frequency approach such as semi-annual OGI. If there are regulatory constraints that require emission reductions to be assessed at the facility level, then an alternative but mathematically similar approach could be to compare reductions at model sites with a probabilistic emissions profile representing a larger population.

3. **Empirical data are used to assess the probability of leak detection.**
   The initial phase of estimating emission reductions is to determine the minimum detection limit of a technology. For most technologies, the detection limit will not be a single value but a function of parameters such as wind speed and distance from source. This is especially true for systems that use dispersion modeling or other algorithms to infer emission rates from ambient concentrations, as this relationship is highly dependent on meteorological conditions.

   A multi-step process may be required to accurately assess the probability of leak detection. First, laboratory testing can evaluate the accuracy, precision, and stability of methane concentration sensors that are a key component of some technologies. These highly controlled tests can gauge sensor performance at measuring methane concentrations under variable conditions such as temperature, relative humidity, and potential cross-sensitive gases.[75] Next, controlled field experiments can be used to determine the probability of detecting different emission rates under a range of known conditions. For example, a Stanford team[76] determined the relationship of detection probability, emission rate, and view distance for OGI by assessing the ability of an OGI camera operator to detect a series of controlled releases

"A multi-step process may be required to accurately assess the probability of leak detection."

[74] Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites, David R. Lyon et al., 50 Environ. Sci. Technol. 9, 4877-4886 (2016)

[75] Environmental Defense Fund Methane Detectors Challenge (accessible at http://business.edf.org/projects/featured/natural-gas/methane-detectors-challenge)

[76] Arvind Ravikumar et al., "Good versus Good Enough?" Empirical Tests of Methane Leak Detection Sensitivity of a Commercial Infrared Camera, 52 Environ. Sci. Technol. 4, 2368-2374 (2018).

at the Methane Emissions Technology Evaluation Center (METEC) at Colorado State University. Moving forward, METEC or facilities like it could play an important role as a respected, independent source for empirical assessments of methane detection methodologies. Ideally, testing should be performed repeatedly under diverse conditions representing the full range that may be encountered in actual use, but in reality this may be difficult to achieve due to the rarity of some meteorological conditions. At a minimum, it is important to challenge technologies with potentially adverse conditions such as extreme heat and cold, stagnant and high winds, and precipitation events. For technologies with well-understood physical principles, physics-based modeling could be used to augment empirical testing by predicting performance under untested conditions.[77]

4. **Standardized models are used to predict emission reductions.** Once there is sufficient empirical data to understand the probability of leak detection under diverse conditions, computer modeling can be used to predict emission reductions from use of the method as part of an LDAR protocol. Models are necessary because the skewed emission rate distribution of O&G facilities means that empirical testing will not fully characterize the impact of a technology across a population of sites. If tests were performed at low-emission sites, then results would be biased towards technologies with the lowest detection limits, while technologies with the shortest detection time would be favored by tests at high emission sites. Theoretically, empirical testing could be performed at a large number of facilities that are statistically representative of the full population, but this likely would be cost prohibitive and require widespread deployment of a technology prior to approval as a valid alternative. Therefore, a rigorous, transparent model is the most cost-effective and quickest approach for predicting emission reductions from leak detection technologies and associated repair protocols. The most likely form of these models is a probabilistic simulation of source-level emissions on a large scale (e.g., the full population of well pads in a state or basin) that uses clearly defined functions and assumptions to predict the detection and mitigation of emissions.

   A rigorous model requires three components to accurately predict reductions: a function defining the probability of detection, a representative emissions profile of the population, and a function defining mitigation in response to detection. The detection function is the direct result of empirical testing and associated physics-based modeling discussed in the previous principle. For any set of valid conditions, the function should return the probability of detection; this function could include a time element since some technologies may use algorithms that have increasing probability to detect leaks as more data are collected. The second

[77] Chandler Kemp, Arvind Ravikumar, and Adam Brandt, Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator, 50 Environ. Sci. Technol. 8 4546-4553 (2016)

component is a quantitative description of emission sources in the population, including their emission rate, source type (as it relates to mitigation), and probability of occurring at a site; this may also include a time component describing the frequency and duration of intermittent emission sources. The third component is a quantitative description of the mitigation response to detected emission sources, which should be based on the repair protocol associated with the technology. For each source type, the emission rate that triggers action to eliminate or reduce emissions from the source should be defined. The temporal aspect is particularly important for this component because the value of high detection limit technologies is dependent on how quickly large emission sources are mitigated. For some approaches, this may be a multi-step process: a technology that detects a high emission rate may trigger a follow-up survey by another technology such as OGI. Therefore, the mitigation response must include the time to initial detection, follow-up detection, and repair. The standardization of the second and third components will be discussed in the final principle.

5. **Model inputs are transparent and rely on best available data**
   Although models are necessary for a cost-effective, timely comparison of methodologies, they can be misused if model inputs are chosen to produce a particular result rather than an objective comparison. Requiring model assumptions to be transparent and scientifically justified can minimize this risk. When possible, inputs such as emission rate distributions should be based on empirical, representative data. For example, if technologies are being compared for their effectiveness in a single state or province, then measurement data collected in that jurisdiction may be most appropriate. In many cases, there may be insufficient data from a specific area, so models will need to use best available data compiled from multiple sources across many areas. To assure consistency across comparisons, it will be advantageous to develop standardized datasets and assumptions to use when more localized data are lacking. For some data parameters, such as emission rate distributions, there is an abundance of publically available data, but other parameters, such as leak recurrence, are either sparse or not in the public domain. The ability to fairly compare technologies can be greatly enhanced by developing open, representative datasets for key model parameters. One approach would be to use an independent party to collect and aggregate data from multiple operators; this would assure the scientific rigor of inputs without revealing sensitive business information. These standardized datasets, which could be regularly updated as new data are available, would improve the transparency and consistency of technology comparisons.

"Requiring model assumptions to be transparent and scientifically justified can minimize this risk."

Recommendations

The first step to encouraging innovation is setting out a rule that permits alternative compliance methodologies and issuing detailed guidance for those who would use the rule. The rule and associated guidance should include guidance on field testing requirements, the approved technology comparison model, submission requirements, and the process for obtaining approval of alternative methodologies. For states that already allow for the use of alternative methodologies, either by rule or general permit, but have not included all of these elements in the alternative compliance provision, only a guidance document may be required rather than a rule or rule revision.

One helpful aspect of the rule and associated guidance should be a clarification that testing a new methodology does not trigger other regulatory requirements. For example, an alert from a novel system should not trigger the requirement to fix a leak or report a leak. The method is by definition in the process of being validated, so it is not yet clear that the alert is accurate. And the risk of triggering mitigation, reporting, and other requirements can deter testing of new methodologies in the most important locations—active oil and gas facilities.

Adopt a shared model for equivalency

The backbone of a methane rule enabling alternative compliance methodologies should be a model that applicants can employ to justify their claim to equal or greater emissions reductions using the proposed methodology. The Technology Comparison Framework section above explains why measurement and modeling must be combined to demonstrate potential impact, how such a model would work, what it can accomplish, and its limitations. A jurisdiction should set out in advance the default assumptions on key variables in the model that it considers reasonable. Approving a model in advance and articulating approvable ranges of values can provide a framework for innovators and operators to direct their thinking as they design new methodologies. Setting approved default ranges for key assumptions encourages innovation because it sets goalposts for innovation and increases the likelihood that an application within bounds will be approved. This reduced uncertainty makes it easier to justify the significant time and energy required to develop and test new methane reduction methodologies.

Comparing the impacts of different methods is a complex exercise, and ozone compliance planning provides a useful example. EPA and states routinely rely on modeling to assess the impact of proposed controls on various goals such as the ability of states to meet national ambient air quality standards for ozone and the amount of anticipated emission reductions from a particular regulatory strategy. Ozone models are capable of accounting for a suite of factors that affect control effectiveness, including meteorology, the fate and transport of ozone precursors, and the source and regional contribution of a specific air contaminant.

The Fugitive Emissions Abatement Simulation Testbed (FEAST) model developed at Stanford is an example of a rigorous model that could be used to evaluate a wide range of technologies.[78] The open-source, field-level model uses a probabilistic Markov model to simulate which components in a field are leaking, with emission rates drawn from existing, empirical datasets. Several different functions are used to determine the probability of detection; for example: 1) Gaussian dispersion modeling to predict detection by distributed methane concentration sensors, and 2) physics-based modeling to predict detection by OGI. Additional functions are used to model the rates at which detected emission sources are repaired and new leaks occur. The model outputs emission reductions over time from each technology's LDAR protocol, plus cost-effectiveness if the inputs include valid cost assumptions. For data elements that are sparse, operators, regulators, and facilities such as METEC can collaborate to fill in the gaps. Operators have an incentive to be forthcoming with data they may otherwise consider private if it is a constructive step toward gaining more flexibility in leak detection and mitigation.

Transparent and rapid process

In order to encourage innovation in methane management, a process that is transparent and fast is just as important as clear submissions guidelines. An alternative compliance rule and associated guidance should lay out the process for approvals, including the opportunities for public comment. Approving the model for evaluating methodologies in advance should facilitate faster and more predictable decision-making on individual applications.

An innovation-encouraging process should include:

- A streamlined **timeline** for decisions;
- A mechanism for applications to be made by operators, technology innovators, and **other interested parties**;
- Opportunities for **public notice and comment**;
- A mechanism to submit information and request it to be **kept out of the public domain** based on legitimate confidentiality concerns;
- A mechanism to submit **one application for multiple sites** (especially relevant in states such as Ohio that operate via individual permits);
- A **public decision**.

Key elements to require in submissions include:

- **Testing results**, preferably independent or verified by a third party;
- **Details of the proposed methodology**, including which instruments will be used where for fixed systems, or with what frequency for mobile systems, and what the mitigation response will be. The submission should also specify how the method combines different instruments—for example, a leak alert from a fixed or mobile monitor triggers a follow-up scan with a more sensitive hand-held instrument
- **Conditions and facilities** where the methodology is proposed to be deployed;

[78] C.E. Kemp, A.P. Ravikumar, and A.R. Brandt, FEAST: Fugitive Emissions Abatement Simulation Toolkit (2016) (accessible at https://eao.stanford.edu/research-areas/FEAST).

- **Modeling** that justifies the claim to equal or greater emissions reductions, including any divergence of inputs from pre-approved ranges;
- Proposed **reporting** and **monitoring** procedures, if different from status quo procedures;
- A proposed **phaseout** of existing detection, monitoring, and reporting requirements

Approvals with powerful benefits

The consequences of an approval, designed well and spelled out in advance, can also encourage time and money to be directed to methane innovation and improve the regulator's ability to accomplish environmental goals.

For **regulators**, approved methodologies can improve the ability to monitor operating conditions and enforce the rules. One opportunity that strengthens a regulator is the ability to adapt reporting requirements to take advantage of the capabilities of new technologies. Many new technologies stream data real-time or employ advanced analytics. Regulators who streamline reporting directly from the systems that operators are already using could see dramatically improved transparency at much lower cost. Regulators can also take advantage of more effective monitoring opportunities. An alternative methodology can combine novel instruments in creative ways. A proposal could include, for example, continuous monitoring at a representative sample of locations for a trial period in order to demonstrate to a regulator that the new method is working and identify opportunities for improvements.

For **innovators**, one regulatory element that expands the potential market is the ability of follow-on operators to use an alternative methodology once it is approved. For similar conditions and similar facilities, a follow-on operator should be able to publicly notify a regulator of the intention to use an approved methodology, which is deemed approved unless the regulator takes action within a short time period. The Colorado rule exemplifies this, as approval of an alternative AIMM can be used by anyone—not just the applicant—so long as the alternative AIMM approval requirements are met.

For **operators**, one regulatory element that encourages collaboration on new methodologies is the prospect of no longer being subject to the existing requirements. If an approved application describes how to phase out use of the status quo for LDAR, the applicant and approved followers should be able to ramp down one methodology after ramping up the alternative.

Interjurisdictional collaboration

The opportunity for regulations to encourage innovation is even stronger with interjurisdictional collaboration. It can take months, and possibly more than a year, for an operator and innovator to test and receive approval for a new methodology in one jurisdiction. The prospect of doing that more than once to receive approval in a subsequent jurisdiction could significantly stifle innovation. On the other hand, the potential of a multi-state market is a strong incentive to invest in the development of better methane management tools and strategies.

The path to streamline interjurisdictional collaboration begins with jurisdictions approving the same model to evaluate alternative methodologies and issuing guidance on assumptions they deem reasonable. An application in a subsequent jurisdiction can then specify how, if at all, the application differs from the first—for example due to different conditions or facilities. If the method, conditions, or facilities are not sufficiently different, new testing does not need to be carried out. The submission may be streamlined, and it may be deemed approved within a reasonable period of time.

As much as possible, all testing should be carried out for the first application. If further testing is required, however, for example because testing was not carried out in extremely low or high temperatures in the first state, then a subsequent state may request more testing. This new testing should be limited to the conditions or facilities that are outside the bounds of the assumptions approved in the first state. In this way, states can encourage innovation that achieves regulatory goals faster and less expensively.