December 1, 2014

Mr. Steven A. Dietrich  
Administrator, DEQ/AQD  
Herschler Building 2-E  
122 W. 25th Street  
Cheyenne, Wyoming, 82002

VIA Regular Mail and Facsimile

Re: Comments on October 2014 Proposed Revisions to Department of Environmental Quality, Air Quality Division, Chapter Eight, Section Six Requirements for Existing Oil and Gas Production Facilities or Sources in the Upper Green River Basin.

Dear Mr. Dietrich:

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF"), Citizens United for Responsible Energy Development ("CURED"), and the Wyoming Outdoor Council ("WOC"). EDF is a national membership organization with over one million members residing throughout the United States who are deeply concerned about the pollution emitted from oil and natural gas sources. WOC is the state’s oldest independent conservation organization and has worked for more than four decades to protect Wyoming’s environment and quality of life for future generations. CURED is a Pinedale based advocacy group and member of the state’s ozone task force.

We greatly appreciate the Air Quality Division’s ("AQD") continued efforts to put in place rigorous clean air measures to protect the health and way of life of citizens living in the Upper Green River Basin ("UGRB"). We believe the proposal rests on a very strong foundation of commonsense, cost effective and proven pollution control measures and commend the Agency for the recent improvements and clarifications contained in the October draft. In particular, we strongly support the extension of the quarterly instrument-based leak detection and repair ("LDAR") measure to compressor stations. For these reasons we believe this proposed rule should be approved at the Air Quality Advisory Board meeting on December 10 in Pinedale.
However, as detailed in our comments below, we believe room remains to improve the protectiveness and workability of the proposal. Data and studies from the UGRB and other basins clearly demonstrate that elevated levels of volatile organic compounds ("VOCs") emitted from oil and gas activities contribute to harmful ozone pollution. Reducing these pollutants is necessary to restore healthy air to the citizens of Pinedale and surrounding communities. Indeed, in light of the Environmental Protection Agency's ("EPA") recent announcement that it will propose lowering the National Ambient Air Quality Standard for ozone to between 60 to 70 parts per billion, realizing all available cost effective reductions is necessary and prudent.

The points we submit for your consideration are:

1) We support the quarterly instrumented inspection requirement for fugitive emissions at compressor stations;
2) However, we request that control requirements apply to pneumatic pumps, pneumatic controllers, storage tanks, and glycol dehydrators located at compressor stations as well as to well sites;
3) We also request the AQD lower the control threshold for fugitive emissions, to two (2) rather than four (4) tons per year ("tpy") of VOCs in order to realize additional cost effective pollution reductions;
4) We do not object to the delayed compliance date provided the Department of Environmental Quality ("DEQ") retains the quarterly instrument-based LDAR requirement for compressor stations; and
5) We request that AQD make the following clarifications in the proposed regulatory language or in the final Statement of Basis Document:
   a. that the proposal applies to all natural gas compressor stations located in the UGRB, regardless of what segment of the natural gas supply chain they belong to; and
   b. that an operator must use an instrument-based method to conduct all four of the quarterly leak detection inspections at well sites and compressor stations; audio, visual, olfactory (AVO) methods standing alone at any of the four quarterly leak detection inspections are not sufficient to meet the terms of the rule.

I. Leak Detection and Repair to Address Leaking Equipment at Compressor Stations

We support the provision requiring quarterly instrument-based inspections of fugitive emissions at compressor stations. As we demonstrated in our comments on the initial

proposal, quarterly inspections are highly cost effective, required in multiple other jurisdictions, and are a critical component of an effective overall emissions reduction program.²

Based on the most recent DEQ inventories, leaking components are one of the largest sources of emissions at compressor stations. In 2011 and 2012 they accounted for approximately 25% of VOC emissions at compressor stations.³ At the national level, fugitive emissions from reciprocating compressors are projected to be the largest source of onshore oil and natural gas methane emissions in 2018.⁴ Other types of leaks from compressors, such as centrifugal compressor seal and reciprocating rod packing, are also among the largest sources of emissions from onshore activities.⁵ Requiring quarterly inspections at compressor stations has the potential to reduce these emissions by 60%.⁶ A 60% reduction from the fugitive emissions reported to DEQ for calendar year 2012 would remove 241 tons of VOCs from the atmosphere.

As we noted in our initial comments, the actual emissions addressed and reductions realized from expanding LDAR to compressor stations may be much larger given that the estimation methods operators use when reporting emissions likely underestimate actual emissions. When reporting emissions for inventory purposes operators use emission factors that represent the average leak rates for various types of components (e.g., flanges, connectors, pumps, valves). These emission factors, by nature, do not account for atypical leak rates that can be caused by inadequate maintenance or operation or improper design.

A number of studies support our view that actual emissions may be significantly greater than estimated emissions. For example, the University of Texas ("U.T.") production study, a national study using direct measurement, rather than estimation methods, found that measured fugitive emissions were 38% higher than estimated emissions reported to EPA.⁷ "Top-down" studies that analyze the concentration of methane and other constituents of natural gas in the air in and near oil and gas producing regions have also found significantly higher emissions than inventory estimates. Studies done in 2012 in Utah’s Uintah Basin and Colorado’s Denver-Julesberg Basin found leak rates significantly higher than what one would expect based on EPA’s Greenhouse Gas ("GHG") Inventory Rule. Specifically, scientists determined that 6-12% of the average hourly natural gas production was leaking in Utah⁸ while 4.1 ± 1.5% of the gas produced in Colorado was leaking.⁹ Reports submitted

² EDF/WOC/CURED July 11 Comments to Mr. Steven A. Dietrich, p. 6, incorporated herein.
³ Id. at 6 (citing 2011 inventory data); DEQ-AQD-Emission Inventory-Composite-Annual-2012-UGRB-Public-Emissions-Inventory.xlsx.
⁴ ICF, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, Fig. 3-4 (March 2014) ("March ICF report").
⁵ Id.
⁶ EDF/WOC July 11 Comments (citing ICF for the proposition that quarterly instrumented inspections have the potential to reduce equipment leaks by 60%).
to EPA indicate that a little less than 1% of the gas produced in the country is lost due to leaks. Some of the disparity between national and regional leak rates can be explained by the differences in the local regulatory frameworks. Utah, for example, requires little in the way of controls and therefore one would expect to find more gas lost due to venting, flaring and equipment leaks than in states with more robust pollution controls required. Nevertheless, the results of these “top-down” studies indicates that the Wyoming UGRB emission inventory may underrepresent actual emissions from existing sources in the Basin, and the U.T. Production Study suggests this may be particularly true for fugitives. Given this data, efforts to control fugitive emissions at compressor stations, as is proposed, are warranted.

A recent study performed by EPA in the Pinedale area suggests one possible explanation for the discrepancy between emission inventory estimates and measured emissions. The study utilized a mobile monitoring method to quantify short-term methane emission rates at 210 oil and gas production sites in the Pinedale Basin, as well as Denver-Julesburg (CO) and Barnett (TX) basins. Mobile monitoring allows for measurement of maintenance-related emissions as well as elevated short-term emissions such as tank flashing. The study used a multivariate linear regression to assess the relationship of emissions to well age, gas production, and hydrocarbon liquids production. According to the authors:

methane emissions were positively correlated with gas production, but only approximately 10% of the variation in emission rates was explained by variation in production levels. The weak correlation of emission rates with production rates indicate that maintenance related stochastic variables and design of production and control equipment are factors determining emissions. (emphasis added).

Perhaps even more important for this proposal, the authors also noted that older wells may be more prone to these random emission events. Per the authors:

Maintenance issues (e.g., fugitive leaks, open or leaking thief hatches, failed pressure relief device, malfunctioning separator dump valves) could be more prevalent at smaller older production sites than at higher producing sites that are potentially better maintained and may have fundamentally different engineering designs (e.g., use of buffer tanks to suppress tank emissions).

These studies demonstrate the need for frequent instrumented inspections at oil and gas facilities such as compressor stations and well sites, in particular at older, existing facilities.

10 Calculated based on national emissions reported to EPA 2012 Greenhouse Gas Inventory.
12 Id. at 1-2.
13 Id. at 18.
As we have previously noted, frequent inspections of facilities is one of the most cost effective ways to identify unintentional and unpredictable leaks. ICF estimates that the net cost of quarterly inspections at compressor stations is only $912 at compressors in the gathering and boosting segment.\textsuperscript{14} For those compressor stations located in the processing and transmission segments, the gas savings exceed the costs making the implementation of quarterly LDAR a net money maker for companies. Per ICF, quarterly inspections at these facilities have a negative cost of $1,438 and $6,399.\textsuperscript{15}

In addition, as the Department has recognized, a number of companies in the UGRB already inspect their compressor stations quarterly.\textsuperscript{16} Holding other operators to the same standards as these leading companies not only levels the playing field among companies but also helps Wyoming retain its position as a leader in clean air practices for the oil and gas industry. So again, we support the proposed regulations for fugitive emissions sources, in particular the new requirement that LDAR be required at compressor stations.

\textbf{II. Common Sense Measures to Reduce Venting at Compressor Stations}

As we noted in our initial comments, equipment leaks are not the only source of pollution at compressor stations. Based on the 2012 inventory, pneumatic controllers and pumps, dehydrators and tanks contributed an additional 242 tons of VOCs in the UGRB. As noted above, actual emissions are likely higher.

The Division has proposed sensible, cost effective requirements to reduce emissions from these sources when located at a well site. It is equally feasible to control these sources when located at a compressor station. Indeed, recent rules adopted by the Colorado Air Quality Control Commission make no distinction between controls required at well sites and those required at compressor stations.\textsuperscript{17} Colorado requires the identical control requirements for existing high-bleed pneumatic controllers, storage tanks, glycol dehydrators and fugitive emissions located at compressor stations as those at well sites.\textsuperscript{18} Importantly, the Colorado rule applies not only to the state’s ozone nonattainment area, but to operations throughout the state. A recent ICF report that evaluated some of the most

\textsuperscript{14} March ICF report at 3-12. This assumes net costs of $6,017 annually coupled with net gas savings of $5,105, assuming gas at $4 per Mcf.

\textsuperscript{15} Id.

\textsuperscript{16} WY AQD Comment Response Concerning the Proposed Wyoming Air Quality Standards and Regulations, Chapter 8, Section 6, Nonattainment Area Regulations (Oct. 31, 2014).

\textsuperscript{17} See 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII-XVIII (Feb. 24, 2014).

\textsuperscript{18} Id. at §§ XVII.C. (tank controls for tanks located at natural gas compressor stations and well production facilities); XVII.D.3. (glycol dehydrator control requirements for dehydrators located at natural gas compressor stations and oil and gas exploration and production operations); XVIII (pneumatic retrofit requirements for controllers located at natural gas compressor stations and well production facilities); see also XVII.F. (LDAR requirements for natural gas compressor stations and well production facilities. The specifications of the LDAR requirements are the same, although the tiers dictating the inspection frequencies vary between well sites and compressor stations.)
cost effective technologies and practices for reducing emissions from onshore oil and gas activities similarly made no distinction between controls available for equipment located at well sites versus other facilities including compressor stations.\textsuperscript{19}

Reducing emissions from pneumatic controllers, pumps, tanks, and glycol dehydrators located at compressor stations can be attained cost effectively. Retrofitting high-bleed controllers with low-bleed ones is one of the most cost effective air pollution reduction steps an operator can take as it pays for itself in less than a year and half\textsuperscript{20} and results in net gas savings of $3.08 and $0.58 per Mcf of natural gas produced, depending on whether the controller is a continuous or intermittent bleed controller, respectively.\textsuperscript{21} As we noted in our July comments, replacing a natural gas driven pneumatic pump with an electric one also yields significant gas savings of $0.22/Mcf for chemical injection pumps and $4.57 per Mcf for Kimray pumps.\textsuperscript{22}

While we feel that flaring is wasteful and should be limited to the greatest extent possible, the practice can be effective in some limited cases as a pollution control method. According to the Colorado Air Pollution Control Division, installing a flare on a storage tank is a highly cost effective way to reduce pollution. Installing a flare on a condensate tank yields an average cost effectiveness of $716 per ton of VOC reduced while using the same control technology to control emissions from crude oil or produced water tanks is cost effective at $427 and $715 tons per VOC reduced, respectively.\textsuperscript{23} Colorado also analyzed the cost effectiveness of requiring existing glycol dehydrators with at least six tons of uncontrolled actual VOCs to control these emissions by 95% using a flare. The Colorado APCD found this strategy also to be highly cost effective at $632 per ton of VOC reduced.\textsuperscript{24}

We urge the DEQ to extend the proposed requirements for pneumatic devices and pumps, glycol dehydrators and tanks located at well sites to compressor stations as well in order to realize these additional cost effective and feasible emission reductions.

\textbf{III. Realizing Additional Air Contaminant Reductions by Addressing A Greater Percentage of Covered Sources}

The AQD proposal leaves significant (and inexpensive) emissions reductions on the table by limiting the control requirement for fugitives to facilities with 4 tpy of VOC emissions, or greater, from these sources. The Statement of Basis indicates that only 3% of facilities with fugitive emissions will be affected by the proposal at the 4 tpy level. The Statement of Basis does not differentiate between controlled versus uncontrolled sources. Therefore, it may

\textsuperscript{19} See March 2014 ICF report.
\textsuperscript{20} Colorado Air Pollution Control Division, Final Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7, 9-10 (Feb. 7, 2014).
\textsuperscript{21} March ICF report at 3-16.
\textsuperscript{22} EDF/WOC July comments at 8.
\textsuperscript{23} Colorado Air Pollution Control Division, Final Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7, 9-10 (Feb. 7, 2014).
\textsuperscript{24} Id. at 34.
underestimate the number of facilities potentially affected by the proposal's 4 tpy threshold since controlled emissions are significantly lower than uncontrolled emissions and therefore are likely to fall below the 4 tpy threshold.

To obtain an alternative perspective on the likely impact of the proposal, we obtained copies of AQD well site permit analyses for all well sites in Sublette County from 2007 to 2014. The permit analyses contain information on the potential uncontrolled fugitive emissions. Our analysis of the information contained in these permits also demonstrates the proposal will apply to only a small percentage of facilities and emissions in the basin, underscoring the need to lower the applicability threshold for the LDAR requirement.

We reviewed each of these 500 permit analyses, noting the fugitive emissions above and below 4 tpy and summing the total emissions estimated for each facility. Based on our review of the permit analyses, a 4 tpy of VOCs threshold for fugitive emissions will only affect 16-17% of facilities and 54% of emissions. In contrast, lowering the threshold to 2 tpy of fugitive VOCs will capture 36%-40% of facilities and 85% of fugitive emissions. Note, these are conservative estimates in that a number of facilities, and therefore emissions, are already implementing at least quarterly inspections as part of voluntary directed and inspection maintenance programs or are required to conduct quarterly inspections pursuant to guidance issued by DEQ in 2013. Thus, the actual impact of the proposal is likely smaller, meaning a smaller percentage of facilities will likely have to implement an LDAR program (because some already are), and thus a smaller percentage of uncontrolled emissions will be affected.

As we have previously noted, requiring frequent inspections of facilities coupled with expeditious repair times is a critical component of an effective pollution reduction program and lowering the control threshold for the LDAR requirement to 2 tpy of VOCs is highly cost effective at $647 per ton of VOC reduced. We strongly urge DEQ to lower the applicability

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25 We limited the data set to well sites in Sublette County rather than the entire UGRB NAA since the Division maintains records at the county rather than partial county level. Therefore, obtaining permit analysis for sites in those parts of Lincoln and Sublette County that are part of the NAA was overly burdensome.

26 We recognize there are certain limitations and uncertainties in the data. One, the permits may not represent facilities or emissions outside Sublette County. Two, some of the facilities have been modified since the time the original analysis was done and thus emissions may have changed. We did not attempt to identify modifications. Three, the analysis does not take into account any subsequent LDAR implemented due to voluntary programs or mandatory permit requirements. However, even with these limitations, we believe the permit analysis presents a credible way to estimate the impact of the proposal on existing facilities and emissions.

27 See EDF analysis, attached hereto as Exhibit 2. The range in the potentially affected facilities, and emissions, turns on whether or not one counts permits that did not contain an actual numeric estimate for fugitive emissions. Some permit analysis simply noted that the fugitive emissions would be "insignificant." The lower range of potentially affected facilities and emissions includes the permits with "insignificant" emissions and assumes such emissions are less than 4 tons per year. The higher range excludes those permits.

28 See EDF/WOC July Comments at 5. Indeed, even a 1 Tpy threshold is well within the bounds of traditional regulatory cost effectiveness metrics. Using the same approach we took to estimate the cost effectiveness of a 2 Tpy threshold, we estimate the cost effectiveness of requiring quarterly LDAR inspections at well sites with 1 tpy of fugitive VOCs to be $2,263 per ton of VOC reduced, assuming $75 in recovered gas.
threshold for LDAR to 2 tpy of VOCs in order to realize additional cost effective pollution reductions.

IV. Delayed Implementation is Acceptable Only if DEQ Retains the Improvements Contained in the October Draft

The current October proposal extends the compliance deadline for affected sources to January 1, 2017, in response to industry comments. This is one year later than the initial proposal provided for. As we stated at the July hearing on the June proposal, immediate reductions in air contaminant emissions are necessary to restore healthy air to the citizens of Pinedale and surrounding communities and we urge the AQD to require such reductions as expeditiously as possible. Nevertheless, we acknowledge the Division’s attempts to respond to differing stakeholder concerns and recognize that the October proposal includes elements requested by both industry (extended compliance date) and environmental organizations (LDAR for compressor stations). In recognition of the Division’s attempts at equity, and in an effort to get a final rule in place as quickly as possible, we are willing to accept the January 1, 2017 compliance deadline provided it is coupled with the improvements the Department has proposed herein, specifically, the quarterly instrumented LDAR program for compressor stations. The additional pollution reductions that will accrue due to this requirement will go a long way towards cleaning up the air in the UGRB, and therefore provide somewhat of a counterweight to the protracted implementation schedule. Without this important requirement, however, we strongly object to any delays beyond the initially proposed January 1, 2016 compliance deadline.

V. Clarifications

We appreciate the clarifications to the rule that the AQD made in the October draft and the Response to Comments document. In particular, we are pleased that the Response to Comments document explained that produced water tanks are subject to the proposed 98% control requirement and that intermittent bleed devices are subject to the retrofit requirement. We are also pleased the AQD has made the availability of replacing a natural gas powered pump with an electric one an explicit compliance option in the proposal. These clarifications add to the workability and enforceability of the rule.

Compliance and enforcement could further be enhanced by clarifying two remaining provisions. The first is the definition of a compressor station. It is our understanding that the AQD’s intent is to require quarterly LDAR at all compressor stations located in the UGRB. This would include those located in the natural gas storage and transmissions segments, as well as those located in the production and processing segments. We do not believe that the current definition makes this clear. The current definition is taken from EPA’s New Source Performance Standards for the oil and natural gas sector.\textsuperscript{29} Importantly, while EPA requires controls for compressors in the production and processing segments, it declined to extend these requirements to compressors in the storage and transmission...

\textsuperscript{29} 40 C.F.R. § 60.5430.
segments when it finalized the NSPS rule in 2012. EPA has since signaled the possibility of extending these controls to the "downstream" compressors located in the storage and transmission segments.\textsuperscript{30} We maintain that such controls, including LDAR, should be equally applicable to such compressors and support AQD’s intent to include such compressors in the proposed LDAR requirement. We request AQD make this intent clear in the Statement of Basis or in the rule language. Possible regulatory language could be the addition of the following text in bold to the current definition:

“Compressor station” means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage, located in the production, processing, transmission or storage segment of the natural gas supply chain.”

The second clarification we request is to the LDAR provision for fugitives. The current language states that all LDAR protocols must include a monitoring schedule “no less frequent than quarterly” consisting of “Method 21, an optical gas imaging instrument, other instrument-based technologies, audio-visual-olfactory (AVO) inspections, or some combination thereof”, but that “an LDAR Protocol consisting of only AVO inspections will not satisfy the requirements of this Subsection.”\textsuperscript{31} Our understanding of this provision is that it requires operators use an instrument-based technology for each and every one of the four inspections each year. This is what is required for new and modified sources in the UGRB. AVO could be used in addition to the four instrument-based inspections. We request the AQD confirm that all four of the quarterly inspections must be done with instrument-based technologies. One option would be to revise the proposed regulatory text to state explicitly that operators must use instrument-based technologies to perform all four of the quarterly inspections. Another option would be to clarify this intent in the final Statement of Basis.

Thank you for accepting these comments. We look forward to working with the AQD and the Air Quality Advisory Board to finalize the proposal expeditiously in order to implement the necessary pollution reduction measures required to restore healthy air to the residents of the Upper Green River Basin.

Respectfully submitted,


\textsuperscript{31} Proposed revisions to WY DEQ AQD REGS Ch. 8, Sec. 6(g)(I)(A)-(D) (Oct. 24, 2014).
Jon Goldstein
Elizabeth Paranhos
Environmental Defense Fund

Bruce Pendery
Wyoming Outdoor Council

Dottie Bentley
CURED
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**TOTAL**                              | **4,884**      | **494**         | **79**                | **16%**                                       | **17%**                                       | **374**               | **36%**                                       | **40%**                                       | **273**               | **50%**                                       | **54%**                                       | **207**             | **44%**                                       | **67%**                                       | **0**               | **0**                             | **0**                        |

[1] Anschutz, Mountain Gas Resources, and Pinedale Energy each had one permit without fugitives listed. These were assumed to be "Insig" (Insignificant) based on other emissions at the facility.
[2] The percentages for each threshold that exclude permits without fugitives do not account for the permits in the "Fugitives not Listed (FNL)" column. This has the largest impact on % breakdowns for Encana, BP, and Questar.
[3] The permits in the "Fugitives listed as Insignificant" column are accounted for in all percentages. These are assumed to have less than 1 tpy (<0.048 tpy) fugitives.
## Fugitive Emissions

<table>
<thead>
<tr>
<th>Operator</th>
<th>Emissions Above 4 tpy</th>
<th>Emissions Below 4 tpy</th>
<th>Emissions Above 2 tpy</th>
<th>Emissions Below 2 tpy</th>
<th>Emissions Above 1 tpy</th>
<th>Emissions Below 1 tpy</th>
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<td>Ultra Resources, Inc.</td>
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<td>201.5</td>
<td>301.9</td>
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<td>44.6</td>
<td>182.2</td>
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<td>Shell Western Exploration &amp; Production Inc. (SWEPI)</td>
<td>57.1</td>
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<td>BP America Production Company</td>
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**Excluding "Insig" and not listed fugitives - TOTAL (tpy)**

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<tr>
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<th>421.5</th>
<th>774.9</th>
<th>137.1</th>
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<td><strong>TOTAL (%)</strong></td>
<td>53.8%</td>
<td>46.2%</td>
<td>85.0%</td>
<td>15.0%</td>
<td>95.3%</td>
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**Assuming "insig" permits have 0.049 tpy fugitives**

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<tr>
<td><strong>TOTAL (%)</strong></td>
<td>53.6%</td>
<td>46.4%</td>
<td>84.7%</td>
<td>15.3%</td>
<td>95.0%</td>
<td>5.0%</td>
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</table>

**Assuming "insig" and not listed permits have 0.049 tpy fugitives**

<table>
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<tr>
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<th>490.5</th>
<th>426.9</th>
<th>774.9</th>
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<tbody>
<tr>
<td><strong>TOTAL (%)</strong></td>
<td>53.5%</td>
<td>46.5%</td>
<td>84.5%</td>
<td>15.5%</td>
<td>94.7%</td>
<td>5.3%</td>
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</tbody>
</table>

[1] 0.049 tpy was selected as the threshold for "insig" and unlisted permit fugitives because it represents the maximum value that would not round up to at least 0.1 tpy and could therefore be considered insignificant. This is a conservative threshold to illustrate the maximum emissions that would fall into the "less than 1 tpy" category.
Assessment of Methane Emissions from Oil and Gas Production Pads using Mobile Measurements

Halley L. Brantley, Eben D. Thoma*, William C. Squier, Birnur B. Guven, David Lyon

109 T.W. Alexander Dr., Research Triangle Park, NC, USA 27711; phone: 1-919-541-7969; fax: 1-919-541-0359; thoma.eben@epa.gov

KEYWORDS. Methane, Oil and Gas, Fugitive Emissions, Mobile Measurements

ABSTRACT. A new mobile methane emissions inspection approach, Other Test Method (OTM) 33A, was used to quantify short-term emission rates from 210 oil and gas production pads during eight two-week field studies in Texas, Colorado, and Wyoming from 2010 to 2013. Emission rates were log-normally distributed with geometric means and 95% confidence intervals (CIs) of 0.33 (0.23, 0.49), 0.14 (0.11, 0.19), and 0.59 (0.47, 0.72) g/s in the Barnett, Denver-Julesburg, and Pinedale basins, respectively. This study focused on sites with emission rates above 0.01 g/s and included short-term (i.e., condensate tank flashing) and maintenance-related emissions. The results fell within the upper ranges of the distributions observed in recent onsite direct measurement studies. Considering data across all basins, a multivariate linear regression was used to assess the relationship of methane emissions to well age, gas production, and hydrocarbon liquids (oil or condensate) production. Methane emissions were positively correlated with gas production, but only approximately 10 % of the variation in emission rates was explained by variation in production levels. The weak correlation between emission and
Wind Direction
Environmental Science & Technology

A&G Paragon Plus Environment
production rates may indicate that maintenance-related stochastic variables and design of
production and control equipment are factors determining emissions.

Introduction
Environmentally responsible development of oil and gas assets requires an understanding of
atmospheric emissions of methane (CH₄) and other organic pollutants as well as their potential
impact on local and regional air quality and greenhouse gas budgets. Emissions are associated
with many different processes in upstream (well development and production) and midstream
(transportation and storage) oil and gas activities¹, ². Although differing in profile, emissions
occur in all phases of well construction, drilling, and completion, and continue as part of the
ongoing production processes³. Oil and gas production pads (pads) typically consist of well
heads, separation units, and storage tanks. Emissions from pads can be difficult to measure and
model due to temporal variability and the large number of potential sources⁴, ⁵. Pad emission
profiles depend on a variety of factors including the geological formation, equipment design and
maintenance state, and on operational procedures. For example, depending on engineering and
control strategies, atmospheric-pressure condensate storage tanks are a significant potential
source of emissions and can be challenging to measure⁶, ⁷. Pad emissions can also vary over time
as wells age and production levels and pressures change. Improving our understanding of
emissions from production sites requires a combination of approaches, including estimating
emissions using engineering calculations for inventories², ⁸, ⁹, direct measurements for refinement
of emission and activity factors¹⁰, and new inspection techniques to inform departures from
routine operations and support compliance activities¹¹.

Direct (onsite) measurements can provide information on component-level emissions, but are
resource intensive, requiring site access and special safety considerations. Furthermore, the high
site-to-site variability decreases the probability of obtaining a representative sample from a small number of sites. To complement direct measurement approaches, a number of research groups are investigating the use of mobile inspection techniques to locate and assess emissions from off-site observing locations\textsuperscript{4, 12, 13, 14}. These emerging approaches vary with respect to execution requirements and emission estimation techniques; however, their mobile nature facilitates identification of unknown emission sources (e.g., pipeline leaks) and anomalous operating conditions (e.g., malfunctions). Unlike direct measurements, mobile approaches typically cannot isolate specific emitting components and are generally less precise than direct measures but are comparatively easier to implement, enabling emission assessments to be made at a greater number of locations on a more routine basis.

This paper describes a novel mobile inspection approach, EPA Other Test Method (OTM) 33A\textsuperscript{17}, and its use to generate CH\textsubscript{4} emission rate data from oil and gas production sites in the Denver-Julesburg (DJ) Basin, the Barnett Shale, Pinedale, and Eagle Ford from 2010-2013. OTM 33A uses a combination of mobile sampling to identify sources and stationary measurements to quantify emissions. In addition to the analysis of repeated measurements at 9 sites, the emission estimates from the OTM 33A field studies were compared with recent on-site studies led by the Eastern Research Group (ERG)\textsuperscript{15} and Allen et al.\textsuperscript{16}. The ERG study\textsuperscript{15}, conducted for the City of Fort Worth, TX, used both direct measurement and source estimation methods to characterize CH\textsubscript{4} and organic compound emissions at 388 production sites containing wells, produced water storage tanks, separators, and compressors. Component-level source identification in the ERG study\textsuperscript{15} was accomplished by infrared camera observations and direct source measurements were conducted using Hi Flow samplers (Bacharach Inc., New Kensington, PA), toxic vapor analyzers, and evacuated canisters. The measurements were used by the City of
Fort Worth to evaluate the adequacy of setback provisions for pads and compressor stations. The results of the ERG study\(^{15}\) indicated that compressors, leaking tank thief hatches, and pneumatic valve controllers are the most frequently encountered and significant emissions sources of CH\(_4\).

Using similar on-site measurement techniques, Allen et al.\(^{16}\) measured CH\(_4\) emissions from 150 production sites in four regions of the United States to evaluate engineering estimates of CH\(_4\) emissions from natural gas production that are used in national inventories. Their results indicated that emissions from pneumatics and equipment leaks were higher than estimated in the EPA greenhouse gas (GHG) emissions inventory\(^{16}\).

**Methods**

OTM 33A\(^{17}\) is a mobile inspection approach used to locate sources and determine real-time emission rates with screening-level accuracy (± 60 %), without the need for site access or location-specific modeling. The technique is applicable to select oil and gas sources such as roadway proximate pads located in relatively open areas. In addition to downwind vehicle access and favorable plume transport conditions required for all mobile assessment methods, the emission characterization portion of OTM 33A relies on relatively consistent meteorological conditions, obstruction-free line of sight observation, and a knowledge of the distance to the source\(^{17}\).

**Sampling Platform Design and Protocol**

The OTM 33A equipment configuration, further described in OTM33A Appendix A\(^{17}\), used either a G1301-fc cavity ring-down spectrometer (Picarro, Inc., Santa Clara, CA, USA) or a GG-24-r off-axis integrated cavity output spectrometer (Los Gatos Research Inc., Mountain View, CA USA) as CH\(_4\) concentration measurement instruments (CMIs). The mobile measurement platforms were sports utility vehicles containing the CMI, computer control system, and battery
systems allowing engine-off instrument operation during stationary observations to prevent self-
sampling of vehicle exhaust. The vehicles were fitted with rotatable front-mounted masts with a
height of 2.7 m allowing the CMI probe and meteorological instruments to be located away from
the body of the vehicle. Primary wind field data were acquired using a model 81000V Ultrasonic
Anemometers (R.M. Young, Inc., Traverse City, MI, USA). A collocated compact auto-north
weather station (model AIO 102780, Climatronics Corp., Bohemia, NY, USA) provided
secondary wind data along with temperature, atmospheric pressure, and relative humidity
measures. Location was recorded using a Hemisphere Crescent R100 Series GPS system
(Hemisphere GPS, Calgary, AB Canada). A LabView™ (National Instruments, Inc., Austin TX,
USA) computer program time-aligned the data stream while allowing user control of the system.
The accuracy, linearity, and range of the CH₄ CMIs was confirmed in pre-deployment testing
with in-field accuracy verified to be within +/- 5% of actual using nominal 20 ppm CH₄ (air
balance) gas standard challenges as per OTM 33 Section 9.4¹⁷. The CMI readings were not
corrected for atmospheric water vapor (OTM 33A Appendix A)¹⁷ which introduces an
approximate 1.5% average negative bias to CH₄ emission determinations for the conditions
encountered in this study.

For a typical pad assessment, emissions were located through downwind, drive-by inspection,
keying on sharply elevated CH₄ spikes indicative of proximate source plumes. Maximizing real-
time CH₄ concentrations measured by the CMI, the vehicle was positioned in the plume at a safe
and appropriate downwind observing location with the probe facing the source, and the engine
was turned off. Distance from the measurement vehicle to the emission source ranged from 10 m
to 200 m with an average distance of 57 m. Data were acquired for a 15- to 20-minute time
period with the vehicle remaining stationary. Auxiliary data from infrared cameras (FLIR
 Systems, Inc., Boston MA, USA), when available, helped identify the source location,
facilitating laser range finder measurements of the distance from the mobile platform to the
source. Distances were later confirmed through Google Earth™ images coupled with wind-
concentration rose data. The vehicle was positioned to minimize line-of-sight wind flow
obstructions.

Emission rate estimates were calculated using a point source Gaussian (PSG) approach with a
custom MATLAB™ (MathWorks, Natick, MA, USA) analysis program (OTM 33A Appendix
F1)\textsuperscript{17}. This approach relies on variations in wind direction to move the plume around the
observation location in three dimensions; further assumptions include a point source and
Gaussian plume dispersion. The analysis software time-aligned the measurements to correct for
sampling line delay, rotated the 3-D sonic anemometer data to polar coordinates centered on the
predominant wind direction, and binned the CH\textsubscript{4} concentrations by wind direction data in ten
degree increments. The results were fitted with a Gaussian function to determine the average
peak CH\textsubscript{4} concentration in the plume. Background concentrations were determined by the
program during time periods with no plume-probe overlap (OTM 33A Section 8.7)\textsuperscript{17}. The
program calculated the representative atmospheric stability indicator (ASI) from an average of
the turbulence intensity (TI), measured by the 3D-sonic anemometer and the standard deviation
in 2-D wind direction (\(\sigma\theta\)), acquired by the compact meteorological station. By defining a seven
unit ASI scale with steps of equal increments (TI = 0.025, \(\sigma\theta = 4.0^\circ\)), an ASI value for each
measurement was assigned which ranged from 1 (TI > 0.205, \(\sigma\theta > 27.5^\circ\)) to 7 (TI < 0.08, \(\sigma\theta <
7.5^\circ\)), roughly corresponding to the Pasquill stability classes A through D\textsuperscript{18}. For the PSG
emission estimate, the values of horizontal (\(\sigma y\)) and vertical (\(\sigma z\)) dispersion are determined from
an interpolated version of point source dispersion tables using the measured source distance and
the ASI (OTM 33A Section 12, Appendix F1)\textsuperscript{17}. The PSG emission estimate \((q)\) is a simple 2-D Gaussian integration (no reflection term) multiplied by mean wind speed \((u)\) and the peak concentration \((c)\) determined by the Gaussian fit: \(q = 2\pi\sigma_y\sigma_z u c\)\textsuperscript{17}.

Method validation using controlled release experiments

A set of 107 controlled CH\textsubscript{4} release experiments were conducted to investigate data quality indicators and the expected accuracy range for the PSG approach in relatively obstruction-free, open areas as encountered in this study (OTM 33A Section 9)\textsuperscript{17}. The experiments used single point releases from slightly dispersed, mass flow-controlled cylinders of 99.9\% CH\textsubscript{4} cylinders, performed at a variety of site locations, observation distances, and under a range of atmospheric conditions. Release rates ranged from 0.19 g/s to 1.2 g/s with 60\% at approximately 0.6 g/s. Based on these experiments, a primary set of three data quality indicators was identified: (1) fitted peak CH\textsubscript{4} concentration centered within +/- 30 degrees of the source direction; (2) an average in-plume concentration greater than 0.1 ppm; and (3) a Gaussian fit with an \(R^2 > 0.80\).

The plume centering indicator helps ensure the identity of the upwind source and can protect against off-axis interfering sources and poor plume advection conditions. The concentration limit helps protect against insufficient plume transport and the \(R^2\) indicator helps identify interfering sources and obstructed wind flow conditions (non-Gaussian transport).

The percent error \((\text{estimated emission rate-release rate}/\text{release rate})\) of the controlled release experiments that met the data quality criteria ranged from -60\% to 52\% with 72\% of the measurements within +/- 30\%. Without application of the data quality indicators, the set of release experiments produced accuracy values ranging from -87\% to 184\% of actual. The 184\% overestimate was believed to be due to pooling and release under partially stagnant conditions and a trial wind variance indicator was developed for this case (not observed in field trials).
Factors affecting accuracy can include insufficient plume advection and non-representative concentration profiles caused by near-field obstructions or poor plume-probe overlap. Potential data quality indicators such as wind speed and plume concentration statistics are being investigated as part of OTM 33A method development\textsuperscript{17}. For the current analysis, only measurements that met the three primary criteria were included (representing 77\% of the controlled release measurements and 71\% of the field measurements).

Description of field studies and production data

OTM 33A was used in eight two-week field campaigns in four oil and gas production basins: Colorado DJ Basin, July 2010 and 2011; Texas Barnett shale, Sept. 2010 and 2011; Texas Eagle Ford Shale, Sept. 2011; and Wyoming Pinedale, which includes the Pinedale Anticline and Jonah fields, June 2011, July 2012, and June 2013. Datasets for each individual basin were combined as the methods of data collection were similar, although there were some software and hardware improvements in later studies. All measurements were collected in the daytime on days with no significant precipitation.

Oil and gas production information for the counties sampled was obtained from DI Desktop (Drillinginfo, Austin, TX, USA). Included in the dataset were well type, operator, first production date, spatial coordinates of the well, and annual and monthly hydrocarbon liquids, gas, and water production levels. OTM 33A measurements were spatially matched with production data using aerial imagery (Google Earth\textsuperscript{19} and ArcGIS\textsuperscript{20} base maps). When coordinates did not align with aerial imagery, additional datasets provided by the State of TX\textsuperscript{21} and State of CO\textsuperscript{22} were used to cross-reference location information. Monthly production values were available for 81\% of the measurements. When monthly production was not available,
annual values were converted to monthly estimates. The matched dataset was analyzed using R\textsuperscript{23}
and ArcGIS 10\textsuperscript{20}.

Both emissions estimates and production values were log-normally distributed and for this reason, data in figures are shown on a log scale. The mean and 95\% CI of the log-transformed data were calculated using a non-parametric bootstrap\textsuperscript{24, 25} and then transformed back into the original scale. The non-parametric bootstrap involved resampling with replacement 1000 times, the mean of each of the samples was taken and the 95\% CIs were calculated from the resulting normally distributed means. The non-parametric bootstrap was chosen because it does not assume the underlying data comes from a normal distribution. To compare OTM 33A emissions estimates with the direct measurement studies conducted by ERG\textsuperscript{15} and Allen et al.\textsuperscript{16}, direct measurements were converted from CH\textsubscript{4} scfm into g/s using a molar volume of 40.87 m\textsuperscript{3} mol\textsuperscript{-1} and summed by site. Measurements from the ERG study\textsuperscript{15} were matched with the corresponding monthly production values from DI Desktop (Drillinginfo, Austin, TX. USA) based on the recorded Entity ID. Production values for the sites measured by Allen et al.\textsuperscript{16} were reported by the well operators to the study team.

Results and Discussion

Description of sites with repeat measurements

The OTM 33A mobile inspection approach was used to identify and assess CH\textsubscript{4} emissions from roadway proximate well pads with an average in-plume concentration enhancement over back ground > 0.1 ppm. No attempt was made to measure or statistically account for well pads with apparently low (and thus difficult to measure) emissions. In many cases, infrared camera videos (examples in Supplemental B) acquired from off-site observing locations, simultaneously with the CH\textsubscript{4} measurements, helped to identify specific emission sources. Storage tank-related
emissions were frequently observed. The emission rates and video examples presented here may not be representative of current conditions due to engineering advancements, changes in work practices, and the implementation of new state regulations.

To improve understanding of both technique and source variability, repeat measurements (three or more) were made at 9 sites in the Pinedale Basin, with the number of measurements per site ranging from 3 to 21 (Table S1). The consistent winds and lack of obstructions in the Pinedale Basin create favorable conditions for OTM 33A. Measurements were made in different years at four of these sites (Figure 1), and the time between measurements ranged from < 1 day to 732 days (Table S1). For sites A-G, the 95 % CI for the geometric mean was less than 1 g/s while at sites H and I, large variations in emissions were observed, resulting in a CI ≥ 2 g/s (Table S1).

![Figure 1. CH\textsubscript{4} emission rates (g/s) measured at repeated sites in Pinedale, WY by year.](image)

The results indicate that while relatively low emissions (< 2 g/s) frequently persist over time, the larger emissions observed using OTM 33A are likely episodic in nature. One source of persistent low-level emissions observed with the infrared camera is believed to be a vented produced water tank at Site C (Video S1). Previous studies have shown that flashing from a
condensate tank after a separator dump can result in episodic large emissions. CH$_4$ emissions greater than 2 g/s were observed at 13 % of the 210 unique sites measured. The variability of emission rates at sites H and I indicates that these larger emissions may be episodic events that cannot be used to infer annual emission rates without a greater understanding of their frequency and duration (Figure 1).

Site I was measured on four separate days in 2012. On each of the days, the emissions appeared to originate from the same tank. Infrared videos indicate that all of the emissions > 3.0 g/s occurred during the time period that a thief hatch on a condensate tank was open (Video S4, Video S5, and Video S6). On the last day the site was measured, the thief hatch was closed and the measured emissions seemed to originate from a pressure relief device and were < 3.0 g/s (Video S7).

Another potential cause of variation in emissions levels is the variability in plume capture. Depending on meteorological conditions, the plume measured can include all of the sources on the pad or only some of the sources (Figure 2). Measurements were made at Site H on three days in 2012 and one day in 2013 (four and two independent emission measurements, respectively). The higher emissions observed were only present on one of the days in 2012 and originated from the tank on the north side of the pad (Video S2) while the smaller emissions seemed to originate from the southern edge of the pad (Video S3).
Figure 2. Map of repeated measurements at sites H and I. The direction of the colored arrows indicate mean wind directions and the locations indicate the locations of the mobile platform during the measurement.

Comparisons of CH₄ emissions by basin and with direct measurement studies

A total of 318 OTM 33A measurements that met the data quality criteria were collected. Of these measurements, 31 were excluded from the analysis because the measured emissions either did not originate from routine pad operations (e.g., evidence of active pad maintenance, pipeline leaks, gas processing plants, etc.) or no current production data were available, resulting in a total of 210 unique sites. The sites were classified into gas or oil pads based on the TX Railroad Commission definition of a gas well²⁶ (> 100 Mscf of gas per barrel of hydrocarbon liquids). Gas pads constituted 93 %, 2 %, 75 %, and 84 % of the sites measured in the Barnett, DJ, Eagle Ford, and Pinedale basins, respectively. Methane emissions were averaged by site and month, resulting in a total of 228 combinations of emission and production values. Due to the small sample size in the Eagle Ford (n = 4), these measurements were excluded from the basin comparison (Figure 3). CH₄ emissions were log-normally distributed with geometric means and 95% confidence intervals (CIs) of 0.33 (0.23, 0.49), 0.14 (0.11, 0.19), and 0.59 (0.47, 0.72) g/s in the Barnett,
Denver-Julesburg, and Pinedale basins, respectively. Emissions by basin were compared using a Kruskal-Wallis one-way analysis of variance test and pairwise Wilcoxon rank-sum tests and were found to be significantly different (p < 0.05). The differences in emissions between basins are likely a result of a combination of factors, including but not limited to: variations in gas and oil production, emissions control devices, and natural gas and oil composition.

Figure 3. Comparison of measured CH₄ emissions per pad (g/s) from Allen et al.¹⁶, ERG¹⁵, and OTM 33A by basin. Boxes represent the 1st and 3rd quartiles of the data, while whiskers extend to the largest measurement that is within 1.5 times the interquartile range (IQR). Means and 95% CIs are shown in black and were calculated using a non-parametric bootstrap.

The OTM 33A measurements were compared with the results of the direct measurement studies of routine pad operations conducted by ERG¹⁵ and Allen et al.¹⁶ (Figure 3). The studies encompass a range of pads that vary with respect to oil and gas composition, production levels, amount and type of production equipment, age, and emission control measures, resulting in a broad distribution of emissions. The mean of the CH₄ emissions measured using OTM 33A in
the Barnett Shale, 0.33 (0.23, 0.48) g/s, is more than twice the mean of the emissions measured by ERG\textsuperscript{14} 0.14 (0.11, 0.18) g/s. Nevertheless, the interquartile range of the OTM 33A measurements in the Barnett falls within the interquartile range of the ERG emissions estimates despite the differences in the measurement methods and the bias towards higher-emitting sites in the OTM 33A measurements.

Both onsite and remote measurement techniques can provide important information on emissions. Whereas direct measurements can accurately quantify component-level emissions, they are less amenable to locating and assessing malfunction-related or large short term emissions such as condensate tank flashing. The measurements by Allen et al.\textsuperscript{16} were limited primarily to equipment leaks, pneumatic controllers, and chemical injection pumps. Condensate tank emissions were measured at some sites but rarely could all of the emission points be accessed. In the ERG study\textsuperscript{15}, due to lack of condensate production, flash emissions were not represented. Although both studies measured fugitive component leaks, neither identified or measured potentially larger maintenance-related emissions (e.g. open thief hatch or failed pressure relief value). In contrast, OTM 33A measurements generally represent an integrated plume including all potential sources on a pad. Supporting infrared camera footage from the OTM 33A studies indicated that emissions often originate from condensate storage tanks which have previously been shown to comprise a significant source\textsuperscript{6, 5} (Supplemental B). OTM 33A is also more likely to capture malfunction-related CH\textsubscript{4} releases than direct measurement methods because of its mobile and off-site measurement capabilities.

However, the remote nature of the OTM 33A method and its application in these studies to only sites with downwind average in-plume concentrations greater than 0.1 ppm result in an effective lower sampling limit of approximately 0.010 g/s, compared with < 0.001 g/s limits for
the on-site measurement techniques (Figure 4a). As a result, the OTM 33A measurements only represent the upper end of the distribution in this comparison (Figure 4b).

Figure 4. Density (a) and cumulative density (b) of measurements of CH₄ emission rates (g/s) from this study (OTM 33A), Allen et al.¹⁶, and ERG¹⁵. Note the logarithmic x-axis.

Comparison of measurements with production values.

CH₄ emissions from the direct measurement studies and OTM 33A were compared to monthly gas production using a linear regression on the log transformed data (Figure 5). Sites with gas production < 1 Mscf/day or CH₄ emissions < 0.0005 g/s were excluded from the analysis (five sites in the ERG study¹⁵). Gas production values explained more of the variation in the OTM 33A measurements than the measurements from the on-site studies, although variation in gas production still accounted for only 8.3% of the total variation in emissions ($R^2 = 0.083$).
Figure 5. CH$_4$ emissions (Mscf/day) versus reported monthly gas production (Mscf/day). Blue lines represent the linear regression lines.

The OTM 33A CH$_4$ emission estimates were also compared with hydrocarbon liquids and water production and the (arithmetic) mean age of active permitted wells on the site using Pearson correlation coefficients (Table 1) and a multivariate linear regression. Approximately 23% and 15% of the pads measured using OTM 33A reported no hydrocarbon liquids or water production, respectively. To use these pads in the log-transformed model, pads with no reported oil or water production were assigned 0.01 bbl/day. Several values were tested and the choice of this value did not significantly affect the results. When considering the correlation between production and emissions individually, CH$_4$ emissions were most strongly correlated with gas production ($R = 0.29$). CH$_4$ emissions were also positively correlated with water production, negatively correlated with mean age, and not correlated with hydrocarbon liquids production (Table 1).

Table 1. Pearson correlation coefficients ($R$) of emissions and production.
<table>
<thead>
<tr>
<th></th>
<th>CH4 Emissions (Mscf/day)</th>
<th>Gas Production (Mscf/day)</th>
<th>Hydrocarbon Liquids Production (bbl/day)</th>
<th>Water Production (bbl/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CH4 Emissions (Mscf/day)</td>
<td>1.00</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas Production (Mscf/day)</td>
<td>0.29</td>
<td>1.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon Liquids Production (bbl/day)</td>
<td>-0.01</td>
<td>0.44</td>
<td>1.00</td>
<td></td>
</tr>
<tr>
<td>Water Production (bbl/day)</td>
<td>0.22</td>
<td>0.77</td>
<td>0.40</td>
<td>1.00</td>
</tr>
<tr>
<td>Mean Age (years)</td>
<td>-0.20</td>
<td>-0.59</td>
<td>-0.34</td>
<td>-0.57</td>
</tr>
</tbody>
</table>

A multivariate linear regression was conducted to determine the effect of gas and hydrocarbon liquids production and age of the well on CH4 emissions simultaneously. Water production was not included in the model because it was so highly correlated with gas production (R > 0.7) that the effects could not be separated. The following model was used:

\[
\log(CH_4) = \beta_1 \cdot \log(Gas) + \beta_2 \cdot \log(Oil) + \beta_3 \cdot Age
\]

where \(CH_4\) represents measured emissions in g/s, \(Gas\) is total reported production in Mscf/day, \(Oil\) is total reported hydrocarbon liquids production in bbl/day, and \(Age\) is the mean age of the wells in years. Age was not significantly correlated with \(CH_4\) emissions, while gas production was significantly positively correlated, and oil production was significantly negatively correlated (Table S2). The negative correlation with oil production is consistent across the basins (Figure S1). This negative correlation with oil production is likely due to the lower fraction of \(CH_4\) in wet gas compared to dry gas. Furthermore, emissions from condensate tanks, which are more prevalent in wet gas areas, typically contain a lower fraction of \(CH_4\) and higher fraction of...
heavier hydrocarbons such as VOCs when compared with produced gas. The inclusion of hydrocarbon liquids and age in the model did not explain much more of the variation in emissions resulting in an adjusted $R^2$ of only 0.096, in contrast to an $R^2$ of 0.083 when only gas production was included.

Other important sources of variation not accounted for in this analysis include emissions controls and equipment present on the pads. Further uncertainty is introduced by the production data: daily or hourly production levels may not be consistent with monthly production.

Although the OTM 33A CH$_4$ emissions data include episodic features (e.g., flash emissions), it is instructive to compare emission rates as a percent of production with the measurements by Allen et al. and ERG. The differences between the CH$_4$ emissions estimates of the three studies are amplified when emissions are considered as a percentage of total production rather than in mass emission rate (Figure S2). For the sites measured using OTM 33A, approximately 0.72 (0.44, 1.17)%, 1.36 (0.97, 1.95) %, and 0.58 (0.39, 0.86) % of production was emitted on average (with 95% CI) in the Barnett, DJ, and Pinedale basins, respectively, compared with 0.11 (0.09, 0.16)% of production measured by ERG in the Barnett shale and 0.01 (0.01, 0.01) % and 0.09 (0.04, 0.20)% measured by Allen et al. in the Appalachian and Rocky Mountain basins, respectively (Figure S2). As evidenced in the statistical analysis, differences in production rate explain only a fraction of the variation in emissions. The percentages from this study only represent emissions from routine well pad operations and thus cannot be directly compared to other estimates of total CH$_4$ emitted as a percent of production such as those by Brandt et al. that include emissions from many other processes.

Mean gas production at the OTM 33A sites was significantly lower than mean gas production at the sites measured in the direct measurement studies (Figure S4). Gas production at the OTM
361 33A sites ranged from 3.7 (Mscf/day) to 9,021 (Mscf/day) with 37% of the sites producing <
362 100 Mscf/day. In contrast, Allen et al.\textsuperscript{16} reported a gas production range of 20 to 47,690
363 (Mscf/day) with only 10% of the sites producing < 100 Mscf/day and with approximately 20%
364 of the measured sites producing > 10,000 Mscf/day. The gas production values of the ERG\textsuperscript{15}
365 sites ranged from 0.06 to 9,085 Mscf/day in the Barnett with 10% of the sites producing < 100
366 Mscf/day (Figure S4). The OTM 33A results indicate that sites with very low gas and oil
367 production can emit a much greater fraction of the gas produced than sites with higher
368 production levels. Maintenance issues (e.g., fugitive leaks, open or leaking thief hatches, failed
369 pressure relief devices, malfunctioning separator dump valves) could be more prevalent at
370 smaller older production sites than at higher producing sites that are potentially better maintained
371 and may have fundamentally different engineering designs (e.g., use of buffer tanks to suppress
372 flash emissions). Furthermore, many of the fugitive processes can emit at levels that are not
373 linearly associated with production rates as is evidenced by the lack of correlation between
374 emissions and production and the finding by Allen et al.\textsuperscript{16} that equipment leaks are
375 underestimated by the 2011 EPA national inventory.
376 In summary, the OTM 33A mobile inspection method can be used to complement direct
377 measurement techniques and expand our knowledge of the upper range of the distribution of CH\textsubscript{4}
378 emissions. OTM 33A was successfully applied to quantify CH\textsubscript{4} emissions at 210 oil and gas well
379 pads with an accuracy of ±60% determined by controlled release tests. Well pad emissions were
380 log-normally distributed and differed significantly by basin with geometric means ranging from
381 0.14 g/s in the Denver-Julesburg to 0.59 g/s in the Pinedale basin. Repeat measurements at 9
382 sites indicated consistent low emission rates at seven sites and highly variable emissions at two
383 sites, one a documented malfunction. The production rates accounted for approximately 10% of
the variation in sampled emission rates in a multivariate linear regression on age, hydrocarbon
liquid and gas production. Normalizing emissions by gas production amplified the differences
between the remote and onsite measurements. Compared to the direct measurements in the
Barnett, the mean of the remote measurements was approximately twice as large as in terms of
mass emissions rate, but approximately seven times as large when considered as a percentage of
production, indicating that sites with lower production levels can emit a much greater percentage
of production. Infrared camera videos indicate that emission rates may be strongly affected by
stochastic variables. In particular, equipment malfunctions or operator error may cause emission
rates to increase substantially compared to routine operating conditions. Accurately estimating
site emissions on a regional scale likely will require determining the average magnitude and
frequency of these stochastic events.

Supporting Information. Supplemental figures, tables, and IR videos are supplied as supporting
information. This material is available free of charge via the Internet at http://pubs.acs.org.

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