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.[1] 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

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[1] Field, R. A. et al. (2014) "Air quality concerns of unconventional oil and natural gas production." Environmental Science: Processes & Impacts, Vol. 15, 954-969, doi: 10.1039/C4EM00081A. Available at: http://pubs.rsc.org/en/content/articlelanding/2014/em/c4em00081a#!divAbstract; Edwards, P. M., et al., (2013) "Ozone photochemistry in an oil and natural gas extraction region during winter: simulations of a snow-free season in the Uintah Basin, Utah." Atmos. Chem. Phys., 13, 8955, doi:10.5194/acp-13-8955-2013. Available at www.atmos-chem-phys.net/13/8955/2013/; Edwards et al., (2014) "High winter ozone pollution from carbonyl photolysis in an oil and gas basin." Nature, 1, doi:10.1038/nature13767.

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 Utah[8] while 4.1 ± 1.5% of the gas produced in Colorado was leaking.[9] Reports submitted

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[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.xlxs.

[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%).

[7] Allen, D.T., et al, (2013) "Measurements of methane emissions at natural gas production sites in the United States," Proc. Natl. Acad. Sci. 2013, 110 (44), 17768-17773; DOI: 10.1073/pnas.1304880110.

[8] Karion, A., et al. (2013) "Methane emissions estimate from airborne measurements over a western United States natural gas field." Geophysical Research Letters, Vol. 40, 4393-4397, doi: 1-.1002/grl.50811. Available at: http://onlinelibrary.wiley.com/doi/10.1002/grl.50811/full.

to EPA indicate that a little less than 1% of the gas produced in the country is lost due to leaks.[10] 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.[11] 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.*[12] (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 devise, 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).[13]

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.

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[9] Petron, G., et al., (2014) "A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin," J. Geophys. Res. Atmospheres, 119, 6863. Available online at: http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/abstract
[10] Calculated based on national emissions reported to EPA 2012 Greenhouse Gas Inventory.
[11] H.L. Brantley, et al, "Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements," at 3, Exh. 1.
[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.[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.[15]

In addition, as the Department has recognized, a number of companies in the UGRB already inspect their compressor stations quarterly.[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.

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.[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.[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

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[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.
[15] Id.
[16] WY AQD Comment Response Concerning the Proposed Wyoming Air Quality Standards and Regulations, Chapter 8, Section 6, Nonattainment Area Regulations (Oct. 31, 2014).
[17] See 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII-XVIII (Feb. 24, 2014).
[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.[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[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.[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.[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.[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.[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.

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

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[19] See March 2014 ICF report.
[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).
[21] March ICF report at 3-16.
[22] EDF/WOC July comments at 8.
[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).
[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.[25] 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.[26] 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.[27] 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.[28] We strongly urge DEQ to lower the applicability

[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.[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

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[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.[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."[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,

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[30] U.S. EPA Office of Air Quality Planning and Standards White Papers: *Oil and Natural Gas Sector Compressors*; (Apr. 2014), http://www.epa.gov/airquality/oilandgas/whitepapers.html; Climate Action Plan Strategy to Reduce
Methane Emissions (Mar. 2014), http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methan e_emissions_2014-03-28_final.pdf.
[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

Wyoming Permit Review

Operator[1]	Total # Wells	Total # Permits	Fugitives (VOCs)[2]													Fugitives not Listed (FNL)	Fugitives listed as Insignificant[3]
			# Permits Above 4 tpy	% Permits above 4 tpy (INCLUDING FNL permits)	% Permits above 4 tpy (EXCLUDING FNL permits)	# Permits Below 4 tpy	# Permits Above 2 tpy	% Permits above 2 tpy (INCLUDING FNL permits)	% Permits above 2 tpy (EXCLUDING FNL permits)	# Permits Below 2 tpy	# Permits Above 1 tpy	% Permits above 1 tpy (INCLUDING FNL permits)	% Permits above 1 tpy (EXCLUDING FNL permits)	# Permits Below 1 tpy		
Ultra Resources, Inc.	1,752	187	5	3%	3%	182	24	13%	13%	163	66	35%	35%	121	0	0
EnCana Oil & Gas (USA) Inc.	1,609	122	28	23%	24%	87	87	71%	76%	28	107	88%	93%	8	7	0
QEP Energy Company	889	71	18	25%	25%	53	33	46%	46%	38	34	48%	48%	37	0	37
Shell Western Exploration & Production Inc. (SWEPI)	388	35	9	26%	26%	26	12	34%	34%	23	12	34%	34%	23	0	23
BP America Production Company	100	40	8	20%	80%	2	9	23%	90%	1	10	25%	100%	0	30	0
Questar Exploration and Production Company	45	9	4	44%	80%	1	5	56%	100%	0	5	56%	100%	0	4	0
Shell Rocky Mountain Production, L.L.C.	44	6	4	67%	67%	2	6	100%	100%	0	6	100%	100%	0	0	0
Yates Petroleum Corporation	19	6	0	0%	0%	6	1	17%	17%	5	1	17%	17%	5	0	0
EOG Resources, Inc.	15	2	0	0%	0%	2	0	0%	0%	2	1	50%	50%	1	0	1
Newfield Production Company	6	4	1	25%	25%	3	1	25%	25%	3	1	25%	25%	3	0	3
Wexpro Company	6	2	2	100%	100%	0	2	100%	100%	0	2	100%	100%	0	0	0
Anschutz Pinedale Corporation	4	3	0	0%	0%	3	0	0%	0%	3	0	0%	0%	3	1	2
Nextraction Energy Corporation	1	1	0	0%	0%	1	0	0%	0%	1	0	0%	0%	1	0	1
Mountain Gas Resources LLC	1	1	0	0%	0%	1	0	0%	0%	1	0	0%	0%	1	1	0
Devon Energy Production Company, L.P.	1	1	0	0%	0%	1	0	0%	0%	1	0	0%	0%	1	0	0
Pinedale Energy, LLC	1	1	0	0%	0%	1	0	0%	0%	1	0	0%	0%	1	1	0
Denbury Onshore, LLC.	2	2	0	0%	0%	2	0	0%	0%	2	0	0%	0%	2	0	0
Chevron USA	1	1	0	0%	0%	1	0	0%	0%	1	1	100%	100%	0	0	0
TOTAL	**4,884**	**494**	**79**	**16%**	**17%**	**374**	**180**	**36%**	**40%**	**273**	**246**	**50%**	**54%**	**207**	**44**	**67**

[1] Anschutz, Mountain Gas Resources, and Palmedale 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" 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 (<0.049 tpy) fugitives.

Fugitive Emissions

Operator	Emissions Above 4 tpy	Emissions Below 4 tpy	Emissions Above 2 tpy	Emissions Below 2 tpy	Emissions Above 1 tpy	Emissions Below 1 tpy
Ultra Resources, Inc.	29.3	140.4	78.8	90.9	136.6	33.1
EnCana Oil & Gas (USA) Inc.	135.5	201.5	301.9	35.1	332.1	4.9
QEP Energy Company	139.5	44.6	182.2	1.9	184.1	0.0
Shell Western Exploration & Production Inc. (SWEPI)	57.1	10.1	67.2	0.0	67.2	0.0
BP America Production Company	64.7	4.9	67.8	1.8	69.6	0.0
Questar Exploration and Production Company	23.9	3.5	27.4	0.0	27.4	0.0
Shell Rocky Mountain Production, L.L.C.	26.9	7.1	34.0	0.0	34.0	0.0
Yates Petroleum Corporation	0.0	5.1	2.0	3.1	2.0	3.1
EOG Resources, Inc.	0.0	1.4	0.0	1.4	1.4	0.0
Newfield Production Company	4.6	0.0	4.6	0.0	4.6	0.0
Wexpro Company	9.0	0.0	9.0	0.0	9.0	0.0
Anschutz Pinedale Corporation	0.0	0.0	0.0	0.0	0.0	0.0
Nextraction Energy Corporation	0.0	0.0	0.0	0.0	0.0	0.0
Mountain Gas Resources LLC	0.0	0.0	0.0	0.0	0.0	0.0
Devon Energy Production Company, L.P.	0.0	0.1	0.0	0.1	0.0	0.1
Pinedale Energy, LLC	0.0	0.0	0.0	0.0	0.0	0.0
Denbury Onshore, LLC.	0.0	1.6	0.0	1.6	0.0	1.6
Chevron USA	0.0	1.2	0.0	1.2	1.2	0.0
Excluding "insig" and not listed fugitives - TOTAL (tpy)	490.5	421.5	774.9	137.1	869.2	42.8
TOTAL (%)	53.8%	46.2%	85.0%	15.0%	95.3%	4.7%
Assuming "insig" permits have 0.049 tpy fugitives [1] - TOTAL (tpy)	490.5	424.8	774.9	140.4	869.2	46.1
TOTAL (%)	53.6%	46.4%	84.7%	15.3%	95.0%	5.0%
Assuming "insig" and not listed permits have 0.049 tpy fugitives [1]- TOTAL (tpy)	490.5	426.9	774.9	142.5	869.2	48.2
TOTAL (%)	53.5%	46.5%	84.5%	15.5%	94.7%	5.3%

[1] 0.049 tpy was selected as the threshold for "insig" and unlisted permit fugitives because it repressesents 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

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7 ABSTRACT. A new mobile methane emissions inspection approach, Other Test Method (OTM)

8 33A, was used to quantify short-term emission rates from 210 oil and gas production pads during

9 eight two-week field studies in Texas, Colorado, and Wyoming from 2010 to 2013. Emission

10 rates were log-normally distributed with geometric means and 95% confidence intervals (CIs) of

11 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,

12 and Pinedale basins, respectively. This study focused on sites with emission rates above 0.01 g/s

13 and included short-term (i.e., condensate tank flashing) and maintenance-related emissions. The

14 results fell within the upper ranges of the distributions observed in recent onsite direct

15 measurement studies. Considering data across all basins, a multivariate linear regression was

16 used to assess the relationship of methane emissions to well age, gas production, and

17 hydrocarbon liquids (oil or condensate) production. Methane emissions were positively

18 correlated with gas production, but only approximately 10 % of the variation in emission rates

19 was explained by variation in production levels. The weak correlation between emission and

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CH$_4$

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20   production rates may indicate that maintenance-related stochastic variables and design of

21   production and control equipment are factors determining emissions.

Introduction

23   Environmentally responsible development of oil and gas assets requires an understanding of

24   atmospheric emissions of methane (CH_4) and other organic pollutants as well as their potential

25   impact on local and regional air quality and greenhouse gas budgets. Emissions are associated

26   with many different processes in upstream (well development and production) and midstream

27   (transportation and storage) oil and gas activities[1, 2]. Although differing in profile, emissions

28   occur in all phases of well construction, drilling, and completion, and continue as part of the

29   ongoing production processes[3]. Oil and gas production pads (pads) typically consist of well

30   heads, separation units, and storage tanks. Emissions from pads can be difficult to measure and

31   model due to temporal variability and the large number of potential sources[4, 5]. Pad emission

32   profiles depend on a variety of factors including the geological formation, equipment design and

33   maintenance state, and on operational procedures. For example, depending on engineering and

34   control strategies, atmospheric-pressure condensate storage tanks are a significant potential

35   source of emissions and can be challenging to measure[6, 7]. Pad emissions can also vary over time

36   as wells age and production levels and pressures change. Improving our understanding of

37   emissions from production sites requires a combination of approaches, including estimating

38   emissions using engineering calculations for inventories[2, 8, 9], direct measurements for refinement

39   of emission and activity factors[10], and new inspection techniques to inform departures from

40   routine operations and support compliance activities[11].

41   Direct (onsite) measurements can provide information on component-level emissions, but are

42   resource intensive, requiring site access and special safety considerations. Furthermore, the high

43   site-to-site variability decreases the probability of obtaining a representative sample from a small

44   number of sites. To complement direct measurement approaches, a number of research groups

45   are investigating the use of mobile inspection techniques to locate and assess emissions from off-

46   site observing locations[4, 12, 13, 14]. These emerging approaches vary with respect to execution

47   requirements and emission estimation techniques; however, their mobile nature facilitates

48   identification of unknown emission sources (e.g., pipeline leaks) and anomalous operating

49   conditions (e.g., malfunctions). Unlike direct measurements, mobile approaches typically cannot

50   isolate specific emitting components and are generally less precise than direct measures but are

51   comparatively easier to implement, enabling emission assessments to be made at a greater

52   number of locations on a more routine basis.

53   This paper describes a novel mobile inspection approach, EPA Other Test Method (OTM)

54   33A[17], and its use to generate CH_4 emission rate data from oil and gas production sites in the

55   Denver-Julesburg (DJ) Basin, the Barnett Shale, Pinedale, and Eagle Ford from 2010-2013.

56   OTM 33A uses a combination of mobile sampling to identify sources and stationary

57   measurements to quantify emissions. In addition to the analysis of repeated measurements at 9

58   sites, the emission estimates from the OTM 33A field studies were compared with recent on-site

59   studies led by the Eastern Research Group (ERG)[15] and Allen et al.[16]. The ERG study[15],

60   conducted for the City of Fort Worth, TX, used both direct measurement and source estimation

61   methods to characterize CH_4 and organic compound emissions at 388 production sites containing

62   wells, produced water storage tanks, separators, and compressors. Component-level source

63   identification in the ERG study[15] was accomplished by infrared camera observations and direct

64   source measurements were conducted using Hi Flow samplers (Bacharach Inc., New Kensington,

65   PA), toxic vapor analyzers, and evacuated canisters. The measurements were used by the City of

66   Fort Worth to evaluate the adequacy of setback provisions for pads and compressor stations. The

67   results of the ERG study[15] indicated that compressors, leaking tank thief hatches, and pneumatic

68   valve controllers are the most frequently encountered and significant emissions sources of CH_4.

69   Using similar on-site measurement techniques, Allen et al.[16] measured CH_4 emissions from 150

70   production sites in four regions of the United States to evaluate engineering estimates of CH_4

71   emissions from natural gas production that are used in national inventories. Their results

72   indicated that emissions from pneumatics and equipment leaks were higher than estimated in the

73   EPA greenhouse gas (GHG) emissions inventory[16].

74   **Methods**

75   OTM 33A[17] is a mobile inspection approach used to locate sources and determine real-time

76   emission rates with screening-level accuracy ($\pm$ 60 %), without the need for site access or

77   location-specific modeling. The technique is applicable to select oil and gas sources such as

78   roadway proximate pads located in relatively open areas. In addition to downwind vehicle access

79   and favorable plume transport conditions required for all mobile assessment methods, the

80   emission characterization portion of OTM 33A relies on relatively consistent meteorological

81   conditions, obstruction-free line of sight observation, and a knowledge of the distance to the

82   source[17].

83   <u>Sampling Platform Design and Protocol</u>

84   The OTM 33A equipment configuration, further described in OTM33A Appendix A[17], used

85   either a G1301-fc cavity ring-down spectrometer (Picarro, Inc., Santa Clara, CA, USA) or a GG-

86   24-r off-axis integrated cavity output spectrometer (Los Gatos Research Inc., Mountain View,

87   CA USA) as CH_4 concentration measurement instruments (CMIs). The mobile measurement

88   platforms were sports utility vehicles containing the CMI, computer control system, and battery

89   systems allowing engine-off instrument operation during stationary observations to prevent self-

90   sampling of vehicle exhaust. The vehicles were fitted with rotatable front-mounted masts with a

91   height of 2.7 m allowing the CMI probe and meteorological instruments to be located away from

92   the body of the vehicle. Primary wind field data were acquired using a model 81000V Ultrasonic

93   Anemometers (R.M. Young, Inc., Traverse City, MI, USA). A collocated compact auto-north

94   weather station (model AIO 102780, Climatronics Corp., Bohemia, NY, USA) provided

95   secondary wind data along with temperature, atmospheric pressure, and relative humidity

96   measures. Location was recorded using a Hemisphere Crescent R100 Series GPS system

97   (Hemisphere GPS, Calgary, AB Canada). A LabView™ (National Instruments, Inc., Austin TX,

98   USA) computer program time-aligned the data stream while allowing user control of the system.

99   The accuracy, linearity, and range of the CH_4 CMIs was confirmed in pre-deployment testing

100   with in-field accuracy verified to be within +/- 5% of actual using nominal 20 ppm CH_4 (air

101   balance) gas standard challenges as per OTM 33 Section 9.4[17]. The CMI readings were not

102   corrected for atmospheric water vapor (OTM 33A Appendix A)[17] which introduces an

103   approximate 1.5% average negative bias to CH_4 emission determinations for the conditions

104   encountered in this study.

105   For a typical pad assessment, emissions were located through downwind, drive-by inspection,

106   keying on sharply elevated CH_4 spikes indicative of proximate source plumes. Maximizing real-

107   time CH_4 concentrations measured by the CMI, the vehicle was positioned in the plume at a safe

108   and appropriate downwind observing location with the probe facing the source, and the engine

109   was turned off. Distance from the measurement vehicle to the emission source ranged from 10 m

110   to 200 m with an average distance of 57 m. Data were acquired for a 15- to 20-minute time

111   period with the vehicle remaining stationary. Auxiliary data from infrared cameras (FLIR

112   Systems, Inc., Boston MA, USA), when available, helped identify the source location,

113   facilitating laser range finder measurements of the distance from the mobile platform to the

114   source. Distances were later confirmed through Google Earth™ images coupled with wind-

115   concentration rose data. The vehicle was positioned to minimize line-of-sight wind flow

116   obstructions.

117   Emission rate estimates were calculated using a point source Gaussian (PSG) approach with a

118   custom MATLAB™ (MathWorks, Natick, MA, USA) analysis program (OTM 33A Appendix

119   F1)[17]. This approach relies on variations in wind direction to move the plume around the

120   observation location in three dimensions; further assumptions include a point source and

121   Gaussian plume dispersion. The analysis software time-aligned the measurements to correct for

122   sampling line delay, rotated the 3-D sonic anemometer data to polar coordinates centered on the

123   predominant wind direction, and binned the CH_4 concentrations by wind direction data in ten

124   degree increments. The results were fitted with a Gaussian function to determine the average

125   peak CH_4 concentration in the plume. Background concentrations were determined by the

126   program during time periods with no plume-probe overlap (OTM 33A Section 8.7)[17]. The

127   program calculated the representative atmospheric stability indicator (ASI) from an average of

128   the turbulence intensity (TI), measured by the 3D-sonic anemometer and the standard deviation

129   in 2-D wind direction ($\sigma\theta$), acquired by the compact meteorological station. By defining a seven

130   unit ASI scale with steps of equal increments (TI = 0.025, $\sigma\theta$ = 4.0°), an ASI value for each

131   measurement was assigned which ranged from 1 (TI > 0.205, $\sigma\theta$ > 27.5°) to 7 (TI < 0.08, $\sigma\theta$ <

132   7.5°), roughly corresponding to the Pasquill stability classes A through D[18]. For the PSG

133   emission estimate, the values of horizontal (σy) and vertical (σz) dispersion are determined from

134   an interpolated version of point source dispersion tables using the measured source distance and

135   the ASI (OTM 33A Section 12, Appendix F1)[17]. The PSG emission estimate (q) is a simple 2-D

136   Gaussian integration (no reflection term) multiplied by mean wind speed (u) and the peak

137   concentration (c) determined by the Gaussian fit: $(q = 2\pi \cdot \sigma y \cdot \sigma z \cdot u \cdot c)^{17}$.

138   <u>Method validation using controlled release experiments</u>

139   A set of 107 controlled CH_4 release experiments were conducted to investigate data quality

140   indicators and the expected accuracy range for the PSG approach in relatively obstruction-free,

141   open areas as encountered in this study (OTM 33A Section 9)[17]. The experiments used single

142   point releases from slightly dispersed, mass flow-controlled cylinders of 99.9% CH_4 cylinders,

143   performed at a variety of site locations, observation distances, and under a range of atmospheric

144   conditions. Release rates ranged from 0.19 g/s to 1.2 g/s with 60% at approximately 0.6 g/s.

145   Based on these experiments, a primary set of three data quality indicators was identified: (1)

146   fitted peak CH_4 concentration centered within +/- 30 degrees of the source direction; (2) an

147   average in-plume concentration greater than 0.1 ppm; and (3) a Gaussian fit with an $R^2 > 0.80$.

148   The plume centering indicator helps ensure the identity of the upwind source and can protect

149   against off-axis interfering sources and poor plume advection conditions. The concentration limit

150   helps protect against insufficient plume transport and the R^2 indicator helps identify interfering

151   sources and obstructed wind flow conditions (non-Gaussian transport).

152   The percent error ([estimated emission rate-release rate]/[release rate]) of the controlled release

153   experiments that met the data quality criteria ranged from -60% to 52% with 72% of the

154   measurements within +/- 30%. Without application of the data quality indicators, the set of

155   release experiments produced accuracy values ranging from -87% to 184% of actual. The 184%

156   overestimate was believed to be due to pooling and release under partially stagnant conditions

157   and a trial wind variance indicator was developed for this case (not observed in field trials).

158　Factors affecting accuracy can include insufficient plume advection and non-representative

159　concentration profiles caused by near-field obstructions or poor plume-probe overlap. Potential

160　data quality indicators such as wind speed and plume concentration statistics are being

161　investigated as part of OTM 33A method development[17]. For the current analysis, only

162　measurements that met the three primary criteria were included (representing 77% of the

163　controlled release measurements and 71% of the field measurements).

164　<u>Description of field studies and production data</u>

165　　OTM 33A was used in eight two-week field campaigns in four oil and gas production basins:

166　Colorado DJ Basin, July 2010 and 2011; Texas Barnett shale, Sept. 2010 and 2011; Texas Eagle

167　Ford Shale, Sept. 2011; and Wyoming Pinedale, which includes the Pinedale Anticline and Jonah

168　fields, June 2011, July 2012, and June 2013. Datasets for each individual basin were combined

169　as the methods of data collection were similar, although there were some software and hardware

170　improvements in later studies. All measurements were collected in the daytime on days with no

171　significant precipitation.

172　　Oil and gas production information for the counties sampled was obtained from DI Desktop

173　(Drillinginfo, Austin, TX, USA). Included in the dataset were well type, operator, first

174　production date, spatial coordinates of the well, and annual and monthly hydrocarbon liquids,

175　gas, and water production levels. OTM 33A measurements were spatially matched with

176　production data using aerial imagery (Google Earth[19] and ArcGIS[20] base maps). When

177　coordinates did not align with aerial imagery, additional datasets provided by the State of TX[21]

178　and State of CO[22] were used to cross-reference location information. Monthly production values

179　were available for 81 % of the measurements. When monthly production was not available,

180 annual values were converted to monthly estimates. The matched dataset was analyzed using R[23]

181 and ArcGIS 10[20].

182   Both emissions estimates and production values were log-normally distributed and for this

183 reason, data in figures are shown on a log scale. The mean and 95% CI of the log-transformed

184 data were calculated using a non-parametric bootstrap[24, 25] and then transformed back into the

185 original scale. The non-parametric bootstrap involved resampling with replacement 1000 times,

186 the mean of each of the samples was taken and the 95% CIs were calculated from the resulting

187 normally distributed means. The non-parametric bootstrap was chosen because it does not

188 assume the underlying data comes from a normal distribution. To compare OTM 33A emissions

189 estimates with the direct measurement studies conducted by ERG[15] and Allen et al.[16], direct

190 measurements were converted from CH_4 scfm into g/s using a molar volume of 40.87 m^3 mol^{-1}

191 and summed by site. Measurements from the ERG study[15] were matched with the corresponding

192 monthly production values from DI Desktop (Drillinginfo, Austin, TX. USA) based on the

193 recorded Entity ID. Production values for the sites measured by Allen et al.[16] were reported by

194 the well operators to the study team.

195 **Results and Discussion**

196 <u>Description of sites with repeat measurements</u>

197   The OTM 33A mobile inspection approach was used to identify and assess CH_4 emissions

198 from roadway proximate well pads with an average in-plume concentration enhancement over

199 back ground > 0.1 ppm. No attempt was made to measure or statistically account for well pads

200 with apparently low (and thus difficult to measure) emissions. In many cases, infrared camera

201 videos (examples in Supplemental B) acquired from off-site observing locations, simultaneously

202 with the CH_4 measurements, helped to identify specific emission sources. Storage tank-related

9

203   emissions were frequently observed. The emission rates and video examples presented here may

204   not be representative of current conditions due to engineering advancements, changes in work

205   practices, and the implementation of new state regulations.

206   To improve understanding of both technique and source variability, repeat measurements

207   (three or more) were made at 9 sites in the Pinedale Basin, with the number of measurements per

208   site ranging from 3 to 21 (Table S1). The consistent winds and lack of obstructions in the

209   Pinedale Basin create favorable conditions for OTM 33A. Measurements were made in different

210   years at four of these sites (Figure 1), and the time between measurements ranged from < 1 day

211   to 732 days (Table S1). For sites A-G, the 95 % CI for the geometric mean was less than 1 g/s

212   while at sites H and I, large variations in emissions were observed, resulting in a CI $\geq$ 2 g/s

213   (Table S1).

214
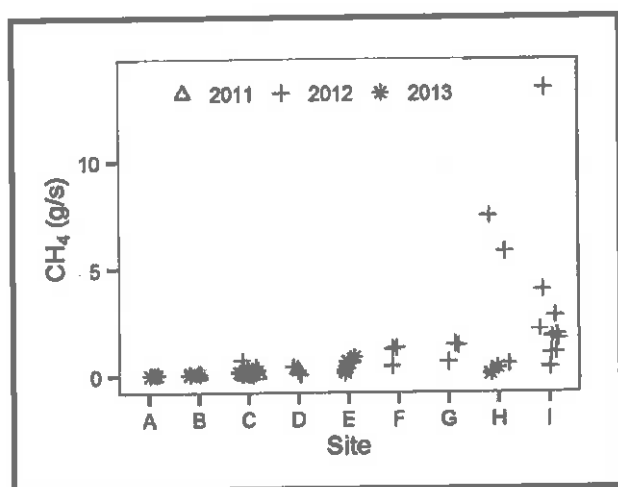
215   **Figure 1.** CH_4 emission rates (g/s) measured at repeated sites in Pinedale, WY by year.

216

217   The results indicate that while relatively low emissions (< 2 g/s) frequently persist over time,

218   the larger emissions observed using OTM 33A are likely episodic in nature. One source of

219   persistent low-level emissions observed with the infrared camera is believed to be a vented

220   produced water tank at Site C (Video S1). Previous studies have shown that flashing from a

221 condensate tank after a separator dump can result in episodic large emissions[6]. CH_4 emissions

222 greater than 2 g/s were observed at 13 % of the 210 unique sites measured. The variability of

223 emission rates at sites H and I indicates that these larger emissions may be episodic events that

224 cannot be used to infer annual emission rates without a greater understanding of their frequency

225 and duration (Figure 1).

226   Site I was measured on four separate days in 2012. On each of the days, the emissions

227 appeared to originate from the same tank. Infrared videos indicate that all of the emissions > 3.0

228 g/s occurred during the time period that a thief hatch on a condensate tank was open (Video S4,

229 Video S5, and Video S6). On the last day the site was measured, the thief hatch was closed and

230 the measured emissions seemed to originate from a pressure relief device and were < 3.0 g/s

231 (Video S7).

232   Another potential cause of variation in emissions levels is the variability in plume capture.

233 Depending on meteorological conditions, the plume measured can include all of the sources on

234 the pad or only some of the sources (Figure 2). Measurements were made at Site H on three days

235 in 2012 and one day in 2013 (four and two independent emission measurements, respectively).

236 The higher emissions observed were only present on one of the days in 2012 and originated from

237 the tank on the north side of the pad (Video S2) while the smaller emissions seemed to originate

238 from the southern edge of the pad (Video S3).

239

11

240

241   **Figure 2.** Map of repeated measurements at sites H and I. The direction of the colored arrows

242   indicate mean wind directions and the locations indicate the locations of the mobile platform

243   during the measurement.

244   <u>Comparisons of CH_4 emissions by basin and with direct measurement studies</u>

245   A total of 318 OTM 33A measurements that met the data quality criteria were collected. Of

246   these measurements, 31 were excluded from the analysis because the measured emissions either

247   did not originate from routine pad operations (e.g., evidence of active pad maintenance, pipeline

248   leaks, gas processing plants, etc.) or no current production data were available, resulting in a

249   total of 210 unique sites. The sites were classified into gas or oil pads based on the TX Railroad

250   Commission definition of a gas well[26] (> 100 Mscf of gas per barrel of hydrocarbon liquids). Gas

251   pads constituted 93 %, 2 %, 75 %, and 84 % of the sites measured in the Barnett, DJ, Eagle Ford,

252   and Pinedale basins, respectively. Methane emissions were averaged by site and month, resulting

253   in a total of 228 combinations of emission and production values. Due to the small sample size

254   in the Eagle Ford (n = 4), these measurements were excluded from the basin comparison (Figure

255   3). CH_4 emissions were log-normally distributed with geometric means and 95% confidence

256   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,

257   Denver-Julesburg, and Pinedale basins, respectively. Emissions by basin were compared using a

258   Kruskal-Wallis one-way analysis of variance test and pairwise Wilcoxson rank-sum tests and

259   were found to be significantly different ($p < 0.05$). The differences in emissions between basins

260   are likely a result of a combination of factors, including but not limited to: variations in gas and

261   oil production, emissions control devices, and natural gas and oil composition.

262

263
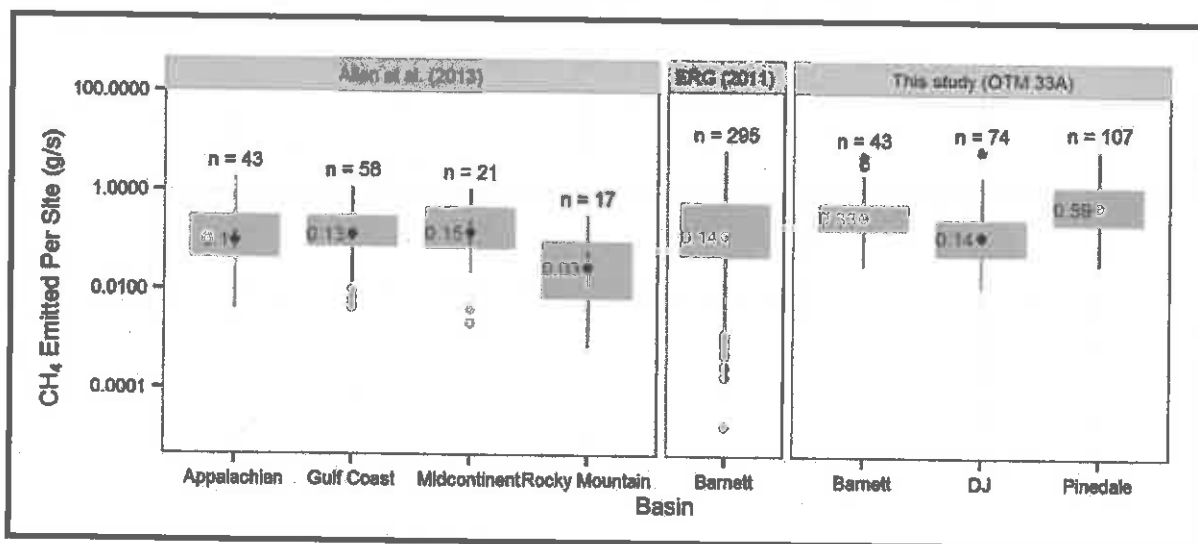
264   **Figure 3.** Comparison of measured CH_4 emissions per pad (g/s) from Allen et al.[16], ERG[15], and

265   OTM 33A by basin. Boxes represent the 1st and 3rd quartiles of the data, while whiskers extend

266   to the largest measurement that is within 1.5 times the interquartile range (IQR). Means and 95

267   % CIs are shown in black and were calculated using a non-parametric bootstrap.

268   The OTM 33A measurements were compared with the results of the direct measurement

269   studies of routine pad operations conducted by ERG[15] and Allen et al.[16] (Figure 3). The studies

270   encompass a range of pads that vary with respect to oil and gas composition, production levels,

271   amount and type of production equipment, age, and emission control measures, resulting in a

272   broad distribution of emissions. The mean of the CH_4 emissions measured using OTM 33A in

273   the Barnett Shale, 0.33 (0.23, 0.48) g/s, is more than twice the mean of the emissions measured

274   by ERG[14] 0.14 (0.11. 0.18) g/s.   Nevertheless, the interquartile range of the OTM 33A

275   measurements in the Barnett falls within the interquartile range of the ERG emissions estimates

276   despite the differences in the measurement methods and the bias towards higher-emitting sites in

277   the OTM 33A measurements.

278   Both onsite and remote measurement techniques can provide important information on

279   emissions. Whereas direct measurements can accurately quantify component-level emissions,

280   they are less amenable to locating and assessing malfunction-related or large short term

281   emissions such as condensate tank flashing. The measurements by Allen et al.[16] were limited

282   primarily to equipment leaks, pneumatic controllers, and chemical injection pumps. Condensate

283   tank emissions were measured at some sites but rarely could all of the emission points be

284   accessed. In the ERG study[15], due to lack of condensate production, flash emissions were not

285   represented.   Although both studies measured fugitive component leaks, neither identified or

286   measured potentially larger maintenance-related emissions (e.g. open thief hatch or failed

287   pressure relief value). In contrast, OTM 33A measurements generally represent an integrated

288   plume including all potential sources on a pad. Supporting infrared camera footage from the

289   OTM 33A studies indicated that emissions often originate from condensate storage tanks which

290   have previously been shown to comprise a significant source[6, 5] (Supplemental B). OTM 33A is

291   also more likely to capture malfunction-related CH_4 releases than direct measurement methods

292   because of its mobile and off-site measurement capabilities.

293   However, the remote nature of the OTM 33A method and its application in these studies to

294   only sites with downwind average in-plume concentrations greater than 0.1 ppm result in an

295   effective lower sampling limit of approximately 0.010 g/s, compared with < 0.001 g/s limits for

296   the on-site measurement techniques (Figure 4a).   As a result, the OTM 33A measurements only

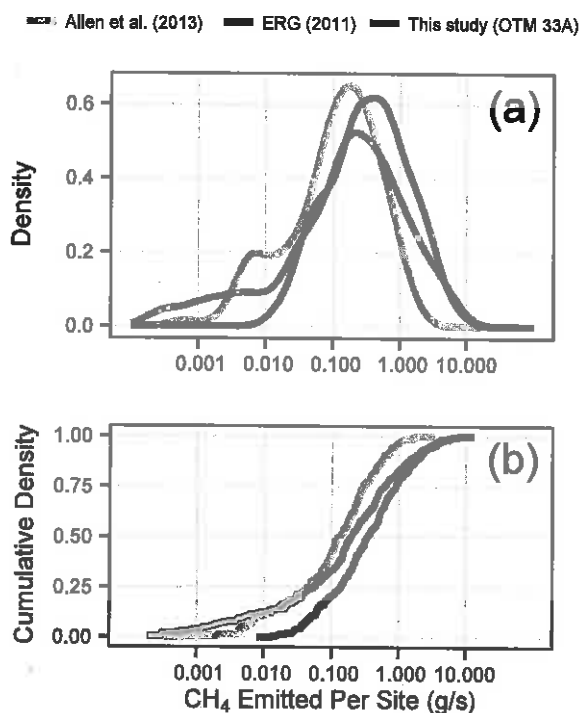297   represent the upper end of the distribution in this comparison (Figure 4b).

298

299   **Figure 4.** Density (a) and cumulative density (b) of measurements of CH_4 emission rates (g/s)

300   from this study (OTM 33A), Allen et al.[16], and ERG[15]. Note the logarithmic x-axis.

301   Comparison of measurements with production values.

302   CH_4 emissions from the direct measurement studies and OTM 33A were compared to monthly

303   gas production using a linear regression on the log transformed data (Figure 5). Sites with gas

304   production < 1 Mscf/day or CH_4 emissions < 0.0005 g/s were excluded from the analysis (five

305   sites in the ERG study[15]). Gas production values explained more of the variation in the OTM

306   33A measurements than the measurements from the on-site studies, although variation in gas

307   production still accounted for only 8.3 % of the total variation in emissions ($R^2 = 0.083$).

308
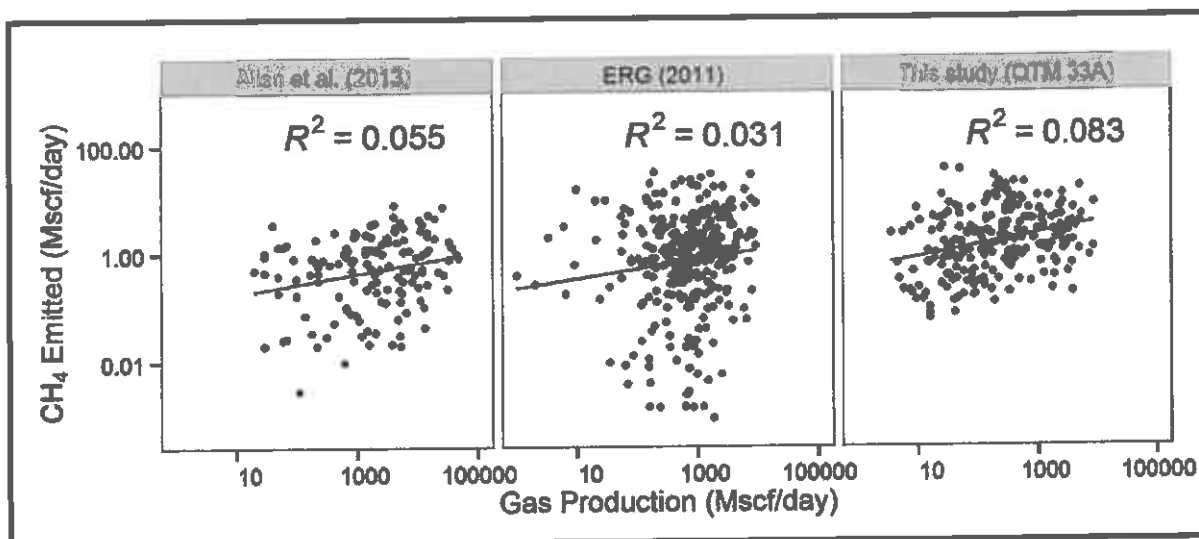
309   **Figure 5.** CH_4 emissions (Mscf/day) versus reported monthly gas production (Mscf/day). Blue

310   lines represent the linear regression lines.

311   The OTM 33A CH_4 emission estimates were also compared with hydrocarbon liquids and

312   water production and the (arithmetic) mean age of active permitted wells on the site using

313   Pearson correlation coefficients (Table 1) and a multivariate linear regression.

314   Approximately 23 % and 15 % of the pads measured using OTM 33A reported no hydrocarbon

315   liquids or water production, respectively. To use these pads in the log-transformed model, pads

316   with no reported oil or water production were assigned 0.01 bbl/day. Several values were tested

317   and the choice of this value did not significantly affect the results. When considering the

318   correlation between production and emissions individually, CH_4 emissions were most strongly

319   correlated with gas production (R = 0.29). CH_4 emissions were also positively correlated with

320   water production, negatively correlated with mean age, and not correlated with hydrocarbon

321   liquids production (Table 1).

322

323   Table 1. Pearson correlation coefficients (R) of emissions and production.

	CH4 Emissions (Mscf/day)	Gas Production (Mscf/day)	Hydrocarbon Liquids Production (bbl/day)	Water Production (bbl/day)
CH4 Emissions (Mscf/day)	1.00			
Gas Production (Mscf/day)	0.29	1.00		
Hydrocarbon Liquids Production (bbl/day)	-0.01	0.44	1.00	
Water Production (bbl/day)	0.22	0.77	0.40	1.00
Mean Age (years)	-0.20	-0.59	-0.34	-0.57

324

325   A multivariate linear regression was conducted to determine the effect of gas and hydrocarbon

326   liquids production and age of the well on CH_4 emissions simultaneously. Water production was

327   not included in the model because it was so highly correlated with gas production ($R > 0.7$) that

328   the effects could not be separated. The following model was used:

329   (1) $\log(CH_4) = \beta_1 * \log(Gas) + \beta_2 * \log(Oil) + \beta_3 * Age$

330   where CH_4 represents measured emissions in g/s, Gas is total reported production in Mscf/day,

331   Oil is total reported hydrocarbon liquids production in bbl/day, and Age is the mean age of the

332   wells in years. Age was not significantly correlated with CH_4 emissions, while gas production

333   was significantly positively correlated, and oil production was significantly negatively correlated

334   (Table S2). The negative correlation with oil production is consistent across the basins (Figure

335   S1). This negative correlation with oil production is likely due to the lower fraction of CH_4 in

336   wet gas compared to dry gas. Furthermore, emissions from condensate tanks, which are more

337   prevalent in wet gas areas, typically contain a lower fraction of CH_4 and higher fraction of

338   heavier hydrocarbons such as VOCs when compared with produced gas[6]. The inclusion of

339   hydrocarbon liquids and age in the model did not explain much more of the variation in

340   emissions resulting in an adjusted R^2 of only 0.096, in contrast to an R^2 of 0.083 when only gas

341   production was included.

342   Other important sources of variation not accounted for in this analysis include emissions

343   controls and equipment present on the pads. Further uncertainty is introduced by the production

344   data: daily or hourly production levels may not be consistent with monthly production.

345   Although the OTM 33A CH_4 emissions data include episodic features (e.g., flash emissions), it

346   is instructive to compare emission rates as a percent of production with the measurements by

347   Allen et al.[16] and ERG[15]. The differences between the CH_4 emissions estimates of the three

348   studies are amplified when emissions are considered as a percentage of total production rather

349   than in mass emission rate (Figure S2). For the sites measured using OTM 33A, approximately

350   0.72 (0.44, 1.17)%, 1.36 (0.97, 1.95) %, and 0.58 (0.39, 0.86) % of production was emitted on

351   average (with 95% CI) in the Barnett, DJ, and Pinedale basins, respectively, compared with 0.11

352   (0.09, 0.16)% of production measured by ERG[15] in the Barnett shale and 0.01 (0.01, 0.01) % and

353   0.09 (0.04, 0.20)% measured by Allen et al.[16] in the Appalachian and Rocky Mountain basins,

354   respectively (Figure S2). As evidenced in the statistical analysis, differences in production rate

355   explain only a fraction of the variation in emissions. The percentages from this study only

356   represent emissions from routine well pad operations and thus cannot be directly compared to

357   other estimates of total CH_4 emitted as a percent of production such as those by Brandt et al.[5]

358   that include emissions from many other processes.

359   Mean gas production at the OTM 33A sites was significantly lower than mean gas production

360   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.[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 [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.[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_4

378   emissions. OTM 33A was successfully applied to quantify CH_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

384   the variation in sampled emission rates in a multivariate linear regression on age, hydrocarbon

385   liquid and gas production. Normalizing emissions by gas production amplified the differences

386   between the remote and onsite measurements. Compared to the direct measurements in the

387   Barnett, the mean of the remote measurements was approximately twice as large as in terms of

388   mass emissions rate, but approximately seven times as large when considered as a percentage of

389   production, indicating that sites with lower production levels can emit a much greater percentage

390   of production. Infrared camera videos indicate that emission rates may be strongly affected by

391   stochastic variables. In particular, equipment malfunctions or operator error may cause emission

392   rates to increase substantially compared to routine operating conditions. Accurately estimating

393   site emissions on a regional scale likely will require determining the average magnitude and

394   frequency of these stochastic events.

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396   **Supporting Information**. Supplemental figures, tables, and IR videos are supplied as supporting

397   information. This material is available free of charge via the Internet at http://pubs.acs.org.

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