Measurements of Methane Emissions at Natural Gas Production Sites in the United States

Study Appendices

David T. Allen, Vincent M. Torres, James Thomas, David Sullivan, Jarett Spinhirne
Center for Energy and Environmental Resources, University of Texas at Austin

Matthew Harrison, Al Hendler, Meggen Delollis, Bryan Benaway, Gene Youngerman, Randy Stevens, Megan Bowien, Kevin McGinn
URS Corporation

Scott C. Herndon, Jon P. Franklin, Cody Floerchinger, Joanne Shorter, Cameron Martin, Ryan McGovern and Joda Wormhoudt
Aerodyne Research, Inc.

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Overview of Content in Study Appendices

The purpose of the project "Measurements of Methane Emissions at Natural Gas Production Sites in the United States" was to improve the accuracy of methane emissions estimates associated with the onshore production of natural gas in the United States. Methane emissions were measured directly at the sources of the emissions, on well sites. Measurements were made in the Gulf Coast, Mid-Continent, Rocky Mountain and Appalachian production regions. The nine companies participating in the study all provided access to their sites for sampling. A total of 150 production sites were sampled, as well as 27 well completion events, 9 well unloading events, and 4 workover events.

The major results of the study have been published in the *Proceedings of the National Academy of Sciences* (PNAS, Allen, et al., 2013). The purpose of the information provided in these Study Appendices is to supplement the material published by the PNAS. The additional information can be broadly categorized as (i) additional background information on the measurement, analysis and review processes used in the study, and (ii) additional data (e.g., fine time resolution information on emission rates) that were not included in the PNAS publication. Some of the fine time resolution data are also available in spreadsheet format downloadable from http://dept.ceer.utexas.edu/methane/study/

Allen, D.T., Torres, V.M., Thomas, J., Sullivan, D., Harrison, M., Hendler, A., Herndon, S.C., Kolb, C.E., Fraser, M., Hill, A.D., Lamb, B.K., Miskimins, J., Sawyer, R.F., and Seinfeld, J.H. Measurements of Methane Emissions at Natural Gas Production Sites in the United States, *Proceedings of the National Academy of Sciences* (2013).

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Appendix A

Scientific Advisory Panel

Appendix A

Scientific Advisory Panel

A six member Scientific Advisory Panel (SAP) provided guidance and advice to the Study Team throughout the project. The role of the panel was to provide independent peer review of the study methodology, the data collected during the study, the analyses of the data, and the conclusions drawn from the data analyses. The members were:

Professor Matthew Fraser, Arizona State University
Professor A. Daniel Hill, Texas A&M University
Professor Brian Lamb, Washington State University
Professor Jennifer Miskimins, Colorado School of Mines
Professor Robert Sawyer, University of California, Berkeley
Professor John Seinfeld, California Institute of Technology

The SAP's six members have extensive expertise in natural gas production, emission estimation and measurement, and air quality measurements and modeling. Brief biographical sketches of the panel members are provided at the end of this Appendix.

The panel provided guidance at three times over the course of the project. The charge to the panel was to address, sequentially, three charge questions:

1. Is the study plan scientifically credible, and is it likely to lead to data collection that meets the study's goals? Within the constraints imposed by the project's schedule and budget, are there improvements that could be made to the measurement methodology and sampling plan?
2. Are the emission measurements and data analyses scientifically credible? Within the constraints imposed by the project's schedule and budget, are there improvements that could be made to the measurements and sampling plan?
3. Is the reporting for the project complete and transparent? Are the conclusions drawn from the study scientifically credible?

In March, 2012, the panel met to review the study plan and data collection methodologies. In August, 2012, the panel met to review preliminary data collection efforts and plans for completion of the sampling. Suggestions from these two Panel meetings were incorporated into the study design, measurements, data analysis and reporting. In January and February 2013, the panel reviewed the draft final report. The panel also participated with the study team, in May and June 2013, in preparing a manuscript, describing the study, that was subsequently published in the Proceedings of the National Academy of Sciences (Allen, et al., 2013).

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Members of the Scientific Advisory Panel

Matthew P. Fraser, Arizona State University

Dr. Fraser is an Associate Professor in the School of Sustainability at Arizona State University (ASU). Dr. Fraser's research focuses on using organic speciation and receptor modeling to apportion ambient pollutants to their source. Dr. Fraser's research group has been involved in field monitoring programs, source characterization studies, emission inventory preparation, and analytical method and instrument development projects. Dr. Fraser received his Bachelors of Science (with University Honors) in Chemical Engineering from Carnegie Mellon University and his Masters and Ph.D. in Environmental Engineering Science from Caltech. Prior to joining the School of Sustainability at ASU, Professor Fraser was on the faculty of Rice University in the Department of Civil and Environmental Engineering.

A. Daniel Hill, Texas A&M University

Professor Hill is Interim Department Head, Professor and holder of the R.L. Whiting Chair in Petroleum Engineering at Texas A&M University. Previously, he taught for twenty-two years at The University of Texas at Austin and spent five years as an Advanced Research Engineer with Marathon Oil Company. He is the author of the Society of Petroleum Engineering (SPE) monograph, *Production Logging: Theoretical and Interpretive Elements*, co-author of the textbook, *Petroleum Production Systems*, co-author of an SPE book, *Multilateral Wells*, and author of over 130 technical papers and five patents. Dr. Hill is an expert in the areas of production engineering, well completions, well stimulation, production logging, and complex well performance (horizontal and multilateral wells). He has presented lectures and courses and consulted on these topics throughout the world. He has also been a Society of Petroleum Engineers (SPE) Distinguished Lecturer, has served on numerous SPE committees and was founding chairman of the Austin SPE Section. He was named a Distinguished Member of SPE in 1999 and received the SPE Production and Operations Award in 2008. He currently serves on the SPE Editorial Review Committee and is Chairman for the SPE Hydraulic Fracturing Technology Conference.

Brian Lamb, Washington State University

Dr. Lamb is Regents Professor in the Department of Civil and Environmental Engineering at Washington State University (WSU). He is well known for his work on biogenic hydrocarbon emissions, turbulence modeling and atmospheric tracer techniques. In the 1990s, he performed emission measurement studies as part of the landmark EPA/GRI study on methane emissions in the natural gas sector. At WSU, he is Co-Director of the Center for Environmental Research, Education, and Outreach (CEREO) and he has won the Bose Research Faculty Award. He has also received the Haagen-Smit prize for his publications on biogenic emissions.

Jennifer L. Miskimins, Colorado School of Mines

Dr. Miskimins is an Associate Professor in the Petroleum Engineering Department at the Colorado School of Mines (CSM). Dr. Miskimins holds B.S., M.S., and Ph.D. degrees in petroleum engineering. Prior to joining CSM, she worked for Marathon Oil Company in a variety of locations. Dr. Miskimins is the founder and Director of the Fracturing, Acidizing, Stimulation Technology (FAST) Consortium at CSM. She teaches a variety of courses including completions and stimulation classes, geologic field camps, and petroleum economics courses at CSM and as industry short courses. She currently serves as the Executive Editor for the SPE Production & Operations Journal and was an SPE Distinguished Lecturer for 2010-2011 in the area of unconventional reservoirs and hydraulic fracturing.

Robert Sawyer, University of California, Berkeley

During his forty-four year career at the University of California, Berkeley as a professor of mechanical engineering, Dr. Sawyer's teaching and research included rocket propulsion, energy conservation, combustion, air pollution and regulatory policy. He has authored more than 350 publications including 2 books. He chaired the Energy and Resources Group and was selected to be the first Class of 1935 Professor of Energy at Berkeley. From 2003-2005 he headed the University of California Education Abroad Program in London. In January 2006, Dr. Sawyer left the University of California to accept the appointment by Governor Schwarzenegger to head the California Air Resources Board, a position he held through June 2007. Currently he is the Class of 1935 Professor of Energy Emeritus at UC Berkeley. He is a graduate of Stanford and Princeton Universities, a fellow of the Society of Automotive Engineers, and a member of the United States National Academy of Engineering.

John H. Seinfeld, California Institute of Technology

John Seinfeld is the Louis E. Nohl Professor in Chemical Engineering at the California Institute of Technology. His research is aimed at improving understanding of the physics and chemistry of atmospheric particles (aerosols), at scales ranging from the urban to the global atmosphere. Dr. Seinfeld is the author of hundreds of publications in the fields of regional and global air quality. He is also the author of a series of widely used textbooks on atmospheric chemistry and physics. His work has been recognized through multiple awards, including membership in the National Academy of Engineering and the National Academy of Sciences. He has won the Haagen-Smit Clean Air Award of the State of California Air Resources Board and the Haagen-Smit Award for excellence in atmospheric sciences publications.

Appendix B

Gas Chromatographic Analyses

Appendix B

Gas Chromatographic Analyses

Gas samples collected during well completions were analyzed in the field, typically on the same day as the samples were collected, using gas chromatography with flame ionization detection. A small fraction of the samples were transported to Austin for analysis (for example, when teams were in the field in different production regions) and were analyzed on arrival. Summaries of the target analytes and quality assurance criteria are listed in the Tables below. Primary gas standards for natural gas components in the form of Standard Reference Materials (SRMs) were obtained from the National Institute for Standards and Technology (NIST).

Target Parameter	Quality Control Check	Quality Control Procedure	Frequency	Acceptance Criteria	Corrective Action
Natural Gas Targets by GC/FID	MDL Study To define method MDLs	MDLs 40 CFR Method Part136 App B	Annually and after major system or procedural modification or repairs	Less than or equal to the compound specific MDLs	Determine problem and rerun the MDL study.
	Calibration (linearity)	Multipoint - 6 component std (3-4 levels + a blank) Level 1 @ 9 % vol CH_4 Level 2 @ 27 % vol CH_4 Level 3 @ 53 % vol CH_4 Level 4 @ 89 % vol CH_4	Daily and following any major maintenance	Linear correlation >0.995 when quantification is by regression OR RSD <20% when quantification is by average RF	Repeat calibration. Determine cause of problem; correct it; and recalibrate. Data is not calculated until an acceptable calibration is obtained.
	MB-System contribution to measurement	Ambient air or zero air sampled under normal conditions	Daily prior to running samples and following any major maintenance	Target compound concentrations less than MDL	Improve system performance to meet spec. and flag those target compounds back to the last good blank and forward to the next good blank.
	CCV-Continuing Calibration Verification	Calibration point 3 level sample.	1 per day	Recovery of each target compound within ±10%	Evaluate retention time window settings. Review chromatography for evidence of similar retention time shifting. Reanalyze control sample to confirm result. Instrument and/or syringe maintenance may be required.

Component	Method	Detector	Sampling period	Detection limit (ppbv)	Precision	Accuracy
Methane	Modified Method 18	FID	Varying	2	≤10%	±10 %
Ethane	Modified Method 18	FID	Varying	0.12	≤10%	±10 %
Propane	Modified Method 18	FID	Varying	0.018	≤10%	±10 %
I-C4/n-C4	Modified Method 18	FID	Varying	0.018	≤10%	±10 %
Neo-C5	Modified Method 18	FID	Varying	0.004	≤10%	±10 %
I-C5/n-C5	Modified Method 18	FID	Varying	0.008	≤10%	±10 %

Appendix C

Estimation of Average Velocity in Temporary Stacks

Appendix C

Estimation of Average Velocity in Temporary Stacks

Velocity measurements in temporary stacks were used in this work to determine the volume of gases emitted from flowback tanks. Velocities were measured near the centerline of the circular stacks and gas flow was estimated by multiplying the gas velocity by the cross sectional area of the stack. Because gas velocity is at a maximum near the centerline of the stack, multiplying the centerline velocity by the stack area will overestimate gas flow.

In this work, the average velocity in the stack will be estimated based on a ratio of average velocity to centerline velocity of 0.8.

Gas flow = (average velocity/centerline velocity) * centerline velocity * stack area

= 0.8 * centerline velocity * stack area

The value of 0.8 for the ratio of average velocity to centerline velocity is based on the following assumptions:

Flow in the stack is turbulent: During the periods when the bulk of the flow occurred through the stacks, flows were in the range of 10-100 scf per minute. For temporary stacks roughly 10 cm in diameter, this led to Reynolds numbers of 4000-10,000+

The velocity, as a function of radius in the stack can be represented by:

$$V_z(r)/V_{z,max} = (1-(r/R))^{1/n}$$

Where V_z is the velocity along the axis of the stack, $V_{z,max}$ is the centerline velocity, r is the radial distance from the center of the stack and n is a parameter that depends on Reynolds number (under the conditions in this work, $6<n<7$*)

With these assumptions, the ratio of average to centerline (maximum) velocity is given by:

$$\text{average velocity/centerline velocity} = 2n^2/((n+1)(2n+1))^*$$

For n=6 this ratio is 0.8; for n=7 this ratio is 0.82. Therefore, for this work, a value of 0.8 will be assumed.

*See Bird, Stewart and Lightfoot, "Transport Phenomena", Wiley, New York, 1960 pg 175.

Appendix D

Determining methane emissions using gas composition data and Hi-Flow measurements

Appendix D

Determining methane emissions using gas composition data and Hi-Flow measurements

The Hi-Flow analyzer used in this work employs a catalytic oxidation unit, followed by a thermal conductivity detector to measure hydrocarbon emission rates. When natural gas emissions are measured, the instrument detects total carbon emissions. For example, for a hypothetical natural gas emission consisting 80% methane (volume), 10% ethane, 5% propane, 3% butane, and 2% pentane, 58% of the carbon is in the form of methane:

$$0.58 = (0.8*1)/(0.8*1+0.1*2+0.05*3+0.03*4+0.02*5)$$

Since the instrument is calibrated based on a flow of pure methane, the instrument will report a "whole gas" volumetric flow assuming that the entire volume is methane. For the natural gas sample above, that "whole gas" volumetric flow would be multiplied by 0.58 to yield the volumetric flow of methane.

This calculation assumes complete oxidation of the natural gas by the instrument. This assumption can begin to break down as the sample stream increases in average molecular weight, however, since the gases analyzed in this work using the Hi-Flow Sampler were generally >80% methane, it will be assumed that complete combustion was achieved. This assumption is supported, for samples with these types of compositions, by detailed instrument calibrations performed by one of the study sponsors.

To calculate methane emission rate based on measurements made by a Hi-Flow instrument calibrated with 100% methane, a gas analysis was required. In this work, gas compositions were reported as mol percentages for N_2, O_2, CO_2, H_2S, methane, ethane, propane, butanes (n-butane and isobutane), pentanes (n-pentane, isopentane and neopentane) and hexanes (and larger) alkanes. Typically, O_2 and H_2S were negligible.

The goal is to calculate the fraction of the carbon that is accounted for by the methane. This fraction is given by:

Total carbon in gas stream = [CO_2] + [methane] + 2*[ethane] + 3*[propane] + 4*[sum of butanes] + 5*[sum of pentanes] + 6*[hexanes]

Fraction methane = [methane]/ [total carbon in gas stream]

The emission rate of methane is the total gas flow (calculated using a Hi-Flow instrument calibrated with using a pure methane source) multiplied by the fraction of carbon accounted for by methane (as calculated above)

To obtain a "whole gas" flow rate, the flow rate of methane (in scf per minute) is divided by the mol percentage of methane in the whole gas analysis. In this work, site specific data on actual whole gas analyses will be used.

Appendix E

Emission Estimates from Tanks

Appendix E

Emission Estimates from Tanks

In order to compare emission estimates based on measurements downwind of production sites to on-site measurements, it was necessary to estimate emissions from water and hydrocarbon tanks. The procedures used in this work are provided below.

Emissions vented from hydrocarbon liquid flowback tank and sent to combustor
Correlations developed by Vazquez and Beggs (1980) were used to estimate dissolved methane. These correlations estimate gas solubility in oil based on temperature, pressure, and oil composition, as characterized by API gravity.

$$Rs = (0.0178 * SG_x * P_i^{1.187}) \exp((23.931 * API) / (T_i + 460))$$

For API>30

R_s	Gas/Oil Ratio of liquid at pressure of interest (scf/BBL)
SG_x	Dissolved gas gravity at 100 psig (density ratio with air)
P_i	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
T_i	Temperature of initial condition (F)

The gas solubility is estimated based on site specific data. The scf/bbl of gas is multiplied by oil production rate in bbl per day, to yield scf of gas vented per day. Methane emissions are estimated by assuming that the vented gas has a similar composition to the produced gas. This likely results in an over-estimate of methane releases from the tanks.

M. Vazquez and H.D. Beggs, Correlations for Fluid Physical Property Prediction, Journal of Petroleum Technology, June, 1980, 968-970.

Emissions vented from water flowback tank
The direct measurements of methane emissions from water flowback tanks were compared to emissions estimated using estimated methane solubility in water. Assuming a Henry's law constant of 4600 (MPa) (pure water, Kiepe, et al., 2003)

Methane partial pressure in the separator was multiplied by the Henry's Law constant to estimate total methane per bbl. The methane per bbl was multiplied by water production rate to calculate total methane vented.

Kiepe, J., Horstmann, S., Fisher, K., Gmehling, J., "Experimental Determination and Prediction of Gas Solubility Data for Methane + Water Solutions Containing Different Monovalent Electrolytes", *Industrial & Engineering Chemistry Research*, 42, 5392-5398 (2003)

Appendix F

Aerodyne mobile van calibration and quality assurance information

Appendix F

Aerodyne mobile van calibration and quality assurance information

The quality control checks used in the field to assess the objectives for this mission are tabulated here. The core gas phase measurement assessment notes are tabulated in Table F-1. The van infrastructure measurement and additional measurement assessment notes are tabulated in Table F-2.

Table F-1 Procedures to Assess Performance Objectives for Gas Phase Measurements

Measurement Parameter	Analysis Method	Assessment Method
Core compounds		
Nitrous Oxide	Fingerprint IR/TILDAS	Span1 – Zero and Span checks are semi-daily when using N_2 overblow.
Methane and isotopologues	Fingerprint IR/TILDAS	Regular Zero (5 mins) and span check hourly. TILDAS instruments in series with own flow check.
Acetylene	Fingerprint IR/TILDAS	Regular Zero (5 mins). We do not have a travelling standard to carry for the acetylene measurement. TILDAS instruments in series with own flow check.
Supplemental data		
Carbon Dioxide	Nondispersive IR	Flow check[1] Zero, Span1 and Span2 prior Span1 checks semi-daily Zero checks semi-hourly
Carbon Monoxide	Fingerprint IR/TILDAS	Zero, Span1, High Concentration Span diluted. Calibrations described in Appendix for Truck manual and performed semi-daily

[1] Sample Flow Rates Designated with this note entry are set using critical apertures that are protected by a high surface area particle filter. The aperture is chosen according to its size designation, however all flow rates are measured using a certified gilibrator to quantify the actual flow rate. Note that the total 'ganged' flow where multiple instruments are joined to the same sample trunk line is also measured. The small disparities (<10%) between the measured total and sum of the Individual flow are due to small pressure drop along the truck sample line. Whenever possible, the calibrations, zeros or instrument span checks are all performed at the inlet tip to ensure the instrument operating pressure and flows are as similar as possible. None of the instruments used in the truck show a systematic dependence on the flow rate and thus, the flow checks are generally performed during the common inlet synthesis. The total flow rate is checked daily along with the examination of the common time response to 'zero' gas overblow. Only if there is an inconsistency or a change of the internal plumbing are the individual instrument flows re-measured.

Table F-2 Procedures to Assess QA objective for Additional Measurements

Measurement Parameter	Analysis Method	Assessment Method
Carbon Containing Species in potential whole air samples	Gas Chromatogram with Flame Ionization Detector	Daily measurements of VOC free air with matched humidity. Daily calibration standards to track retention times. Pre-campaign determination of the mV*s/g carbon using three different standard tanks. In-field checks of the response per ppmC are done with the calibration chromatograms
Webcam Image	NA	As the measurement sortie is begun, the frequency of image capture is increased and verified. Images saved as Jyyyymmdd_hhmmss.jpg and later organized via igor script into hourly folders to keep limit each folders file count to 3600 files. An index is also constructed for random access during data analysis and playback.
Wind Speed and Direction	Rotary Vane (direction) magnetic sensor (speed)	The anemometer direction is checked against a coordinated manual manipulation of the anemometer vane along the four quadrants (ahead, driver, passenger, rear). Wind speed calibration is compared by looking at the GPS velocity signal during a mobile condition with light ambient wind.
Position	Global Position System (GPS)	Examining the output from the GPS compared to an online source such as google maps verifies the function. All mobile sorties are mapped into the UTM coordinate space to put traces onto a georeferenced image of the roadway, terrain, facility boundaries

Gas Phase Measurement Instrument Assessment

The core tracer compounds described in Table F-1 are evaluated in real time. By real time analysis of the enhancement ratios for the tracer and methane species, the passenger in the mobile lab determined whether the mobile lab was suitably positioned. Each real-time instrument operates on different physical principles; however, they all require established baselines for quantitative measurements. True "no signal" baselines were established periodically during mobile lab operation by introducing zero air into the mobile laboratory-sampling manifold, exposing all instruments to a "no pollutant" stable air sample. Background ambient air and plume pollutant levels were measured from the zero air baseline. Each instrument was then calibrated by introducing known levels of gaseous species into the sampling manifold. In the case of the most important trace gases (CH_4, N_2O, C_2H_2, CO and CO_2), calibration gas cylinders with known trace gas levels, traceable to National Institute of Standards and Technology (NIST) standards, were used for absolute calibration. Calibrations are periodically performed using calibration gas cylinders carried onboard the mobile laboratory.

Some commercial instruments (LI-COR CO_2, Themo Environmental NO) have standard calibration procedures prescribed by their manufacturers that were implemented during the field campaign. For example, the carbon dioxide measurements are made by two LI-COR model LI-6262 detectors and by a higher range model 820 detector. The accuracy and linearity of the LI-COR detectors are periodically checked by overflowing the inlet with gas directly from one of two standard calibration tanks (400 ppm and 803 ppm, ± 1%, Scott Specialty Gases) or with CO_2-free nitrogen.

Appendix G

Pneumatic controller data analysis

Appendix G

Pneumatic Contoller Data Analysis

Introduction

Pneumatic controllers do not all have continuous emissions. Figure G-1 shows typical temporal emission profiles for controllers sampled in this work. Because pneumatic controllers sometimes operated at a very low frequency (for example if the controller was associated with liquid flow for a well that produced very little liquid), pneumatic controllers at most sites were selected randomly for measurement. At some sites, however, the controllers that were observed to have emissions were selected for sampling. Both of these populations were considered as a single data set. This Appendix presents the statistical analyses done by the study team to justify the combination of data sets.

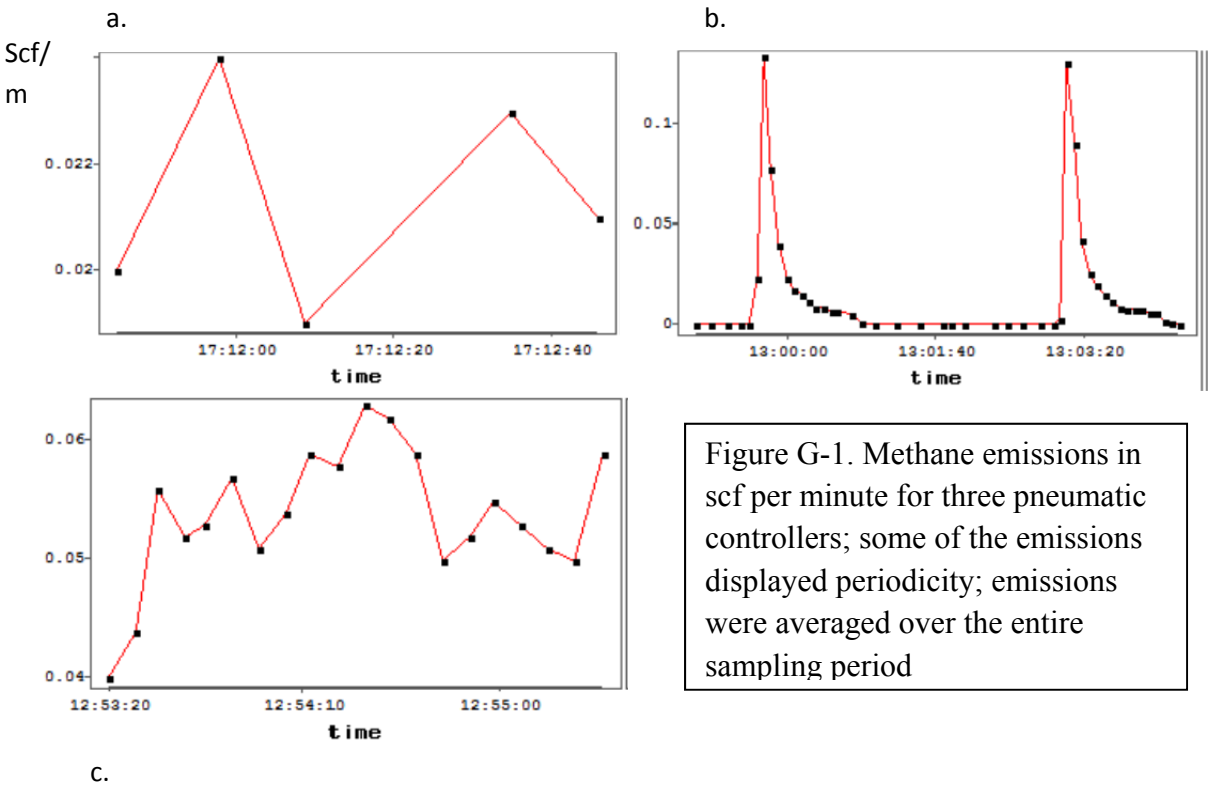


Figure G-1. Methane emissions in scf per minute for three pneumatic controllers; some of the emissions displayed periodicity; emissions were averaged over the entire sampling period

Pneumatics Measurements at Production Sites

The pneumatics controller emissions were determined using a Hi-Flow Sampler, with a protocol that remained the same for the duration of the project. Processing of the data, using the time average of all the readings for a particular device (see Figure G-1), remained the same throughout the project. However, the means of selecting which pneumatic devices would be

measured evolved during the process as the field effort progressed. In many cases, only a subset of the devices at a site were measured.

In the initial field measurements in south Texas, pneumatic measurements with the Hi-Flow Sampler were made only for pneumatic controllers where an infrared camera had identified that the device was emitting gas. This may have biased the selection to high emitters, but a statistical comparison of the initial Texas samples to later samples selected randomly showed no statistically significant difference. As many pneumatic controller devices intermittently discharge, this may show that a FLIR sample, which lasts only for 20-30 seconds per device, may not itself identify "high emitters" as it is only valid for the short time period when the FLIR was aimed at a device. It is possible that many different subsets at a given site would adequately represent the site's pneumatic devices.

On remaining sites after the initial Texas effort, the selection of pneumatic devices was made more randomly. Of the two field teams, one team switched completely to a random subset of pneumatic devices, or in cases of small sites, all devices at the site were measured. The FLIR was not used to select which controllers to measure. The second team continued to use the FLIR to identify devices with emissions, though that team also measured some additional devices. Statistical review of the results showed that where comparisons can be made between the results of the different sampling teams, in one case the team using the FLIR camera measured leak rates statistically significantly higher than another team, while the reverse was true in another region. So the difference that might be associated with different sampling protocols appears to be small compared to the differences in activity at production sites or the integrity of components operating at production sites. Again, this may indicate that selection of pneumatic controllers to be sampled can be done in a number of ways. Overall, however, random or complete sampling is a scientifically superior approach, and will be used in any subsequent study.

Appendix H

Completion Data Reports

Appalachian Completion Data Reports 1-5 (pages 25-48)

Gulf Coast Completion Data Reports 1-7 (pages 49-99)

Midcontinent Completion Data Reports 1-5 (pages 100-127)

Rocky Mountain Completion Data Reports 1-10 (pages 128-175)

Appalachian Completion 1 Data Report

Well information
Company: AP-A

Surface Equipment Configuration
Initial flowback went to a vented tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. After the initial flow, flow was routed to a separator. Gas from the separator went to flare and liquid from the separator was routed to the same flowback tank that initial flow was sent to. The entire flowback lasted for 62.5 hours.

Flowback timeline
Hours 0-40: Flow to vented flowback tank

Hours 40-62.5: Flow to a separator with gas to flare and liquids to the same flowback tank used for initial flow

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 57,000 scf

Gas to flare (from completion report): 1,060,000 scf

Gas Samples
Vented tank gas samples

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
21 hours 30 min	Grab	N.D.
23 hours 15 min	Grab	17.21
25 hours 30 min	Grab	64.41
29 hours 0 min	Grab	74.20
46 hours 0 min	Grab	3.09
47 hours 0 min	Grab	2.54
48 hours 0 min	Grab	3.38
49 hours 0 min	Grab	3.78
51 hours 0 min	Grab	3.31
52 hours 0 min	Grab	2.90
53 hours 0 min	Grab	3.08
54 hours 0 min	Grab	4.17

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Appalachian Completion 1 found in the study database. The data are summarized in Figure AP1-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Appalachian Completion 1 found in the study database.

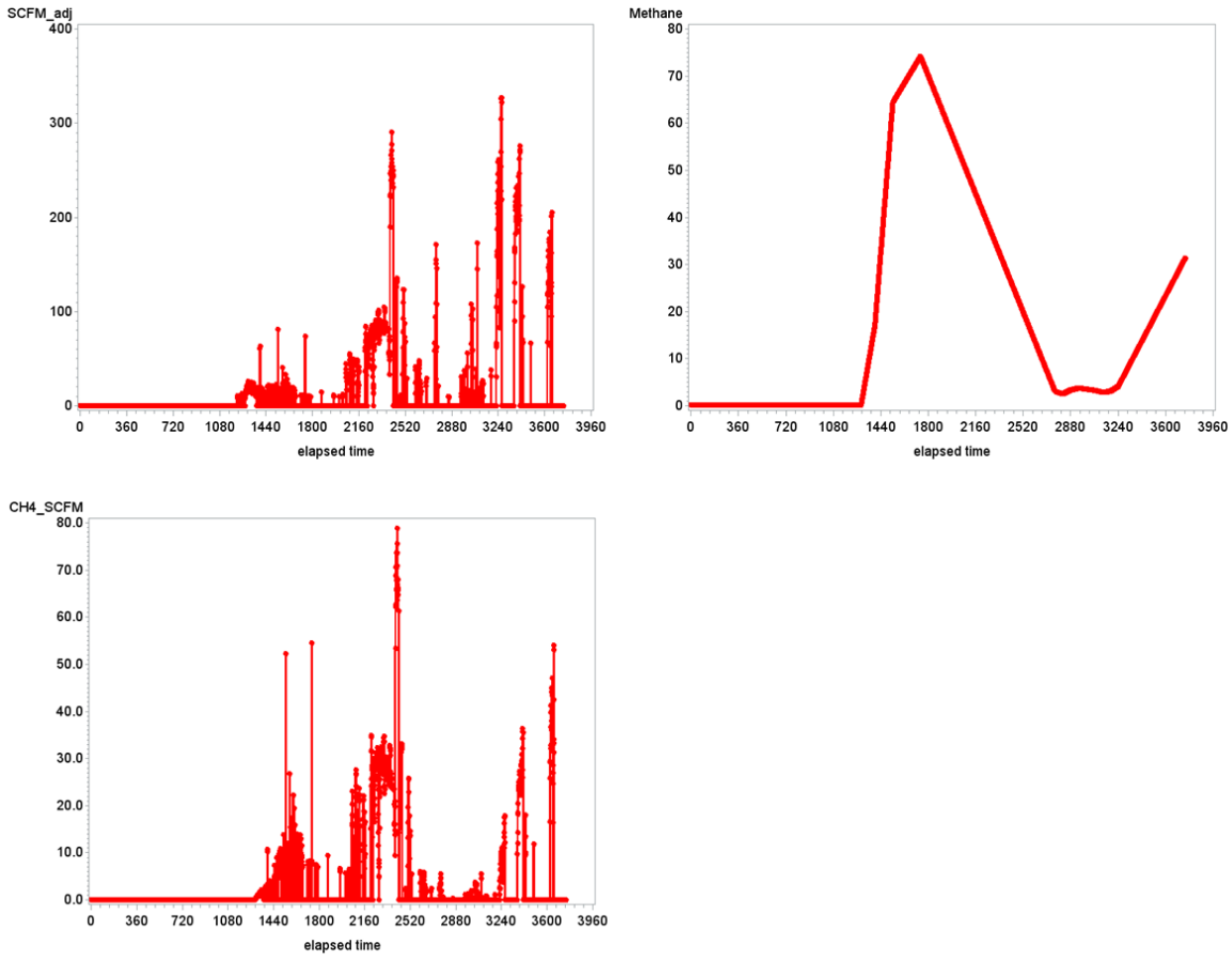
Emissions estimate = 12,700 ± 10,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 1,270
Combined uncertainty = ± 10,490

Figure AP1-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 57,000 ft^3 over 3751minutes (62.5 hours)
Cumulative total methane: 12,700 ft^3 over 3751 minutes (62.5 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [2,800- 37,000]



Emissions from gas sent to flare:
A total of 1,060,000 scf of gas was sent to the flare. An estimate of methane sent to the flare would be to assume that the gas, for the entire period, was the composition of gas that had the highest percentage of methane of the samples collected from the same well pad (presumably gas from the separator would, on average, be higher in methane than the gas from the separator blowdown liquid, diluted by air in the flowback tank)

1,060,000 scf * 0.74 mol fraction methane = 785,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

785,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 16,000 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to vented tank	12,700 ± 10,500 scf	
Emissions from flare		16,000scf
Total (based on centerline gas velocity measurements)	29,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	26,000± 8000 scf	

Potential emissions:

785,000 scf sent to flare + 3,000 scf from vented tank = 788,000 scf methane

Appalachian Completion 2 Data Report

Well information
Company: AP-B

Surface Equipment Configuration
Nearly entire flowback went from the well, through a separator, to a vented flowback tank. The separator was operated at a pressure of 100 psig. Gas from the separator was sent to flare. The liquid from the separator was sent to a vented flowback tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis.

Flowback timeline
Hours 0-38: Flowback to a separator; gas from the separator to flare; liquid from the separator to a vented flowback tank.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack: 11,800 ft^3

Gas Samples
Vented flowback tank gas samples

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
24 hours 40 min	Grab	N.D.
25 hours 04 min	Grab	14.16
25 hours 25 min	Grab	79.88

Emission calculations

Emissions measured through temporary stack during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Appalachian Completion 2 found in the study database. The data are summarized in Figure AP2-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Appalachian Completion 2 found in the study database.

Emissions estimate = 6,700 ± 500 scf

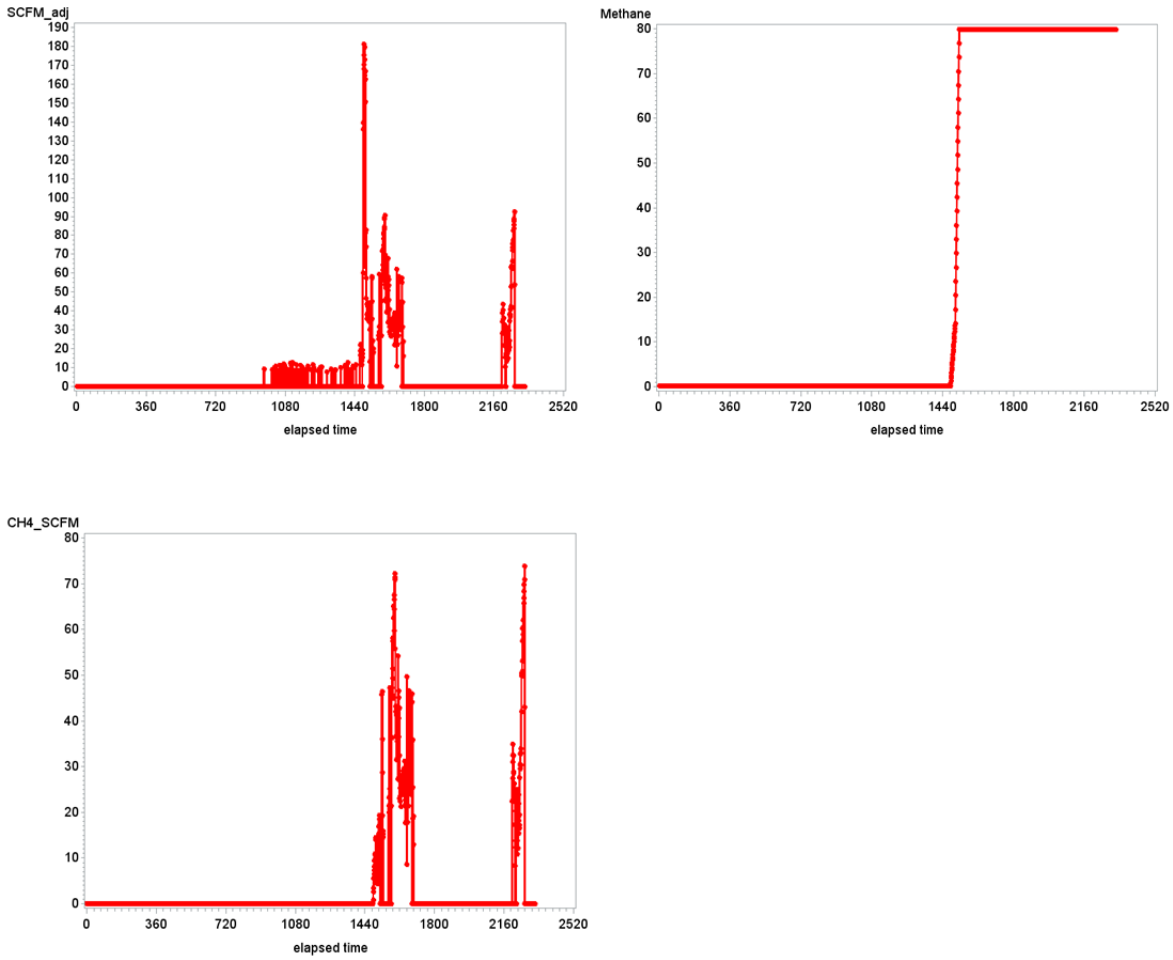
A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 670
Combined uncertainty = ± 840

Figure AP-2 Flowback into vented tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 11,800 scf over 2268 min (37.8 hr)
Cumulative total methane: 6,700 scf over 2268 min (37.8 hr)

Two other estimates based on using the upper and lower ends of possible methane percentage: [6,440-7250]



Emissions from gas sent to flare:
A total of 65,000 scf of gas was sent to the flare. An estimate of methane sent to the flare would be to assume that the gas, for the entire period, was the composition of gas that had the highest percentage of methane of the samples collected from the same well pad (presumably gas from the separator would, on average, be higher in methane than the gas from the separator blowdown liquid, diluted by air in the flowback tank)

65,000 * 0.80 mol fraction methane = 52,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

52,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 1,000 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to vented tank	6,700 ± 840 scf	
Emissions from flare		1,000scf
Total (based on centerline gas velocity measurements)	7,700 ± 840 scf	
Total (based on estimated average gas velocity – see Appendix C)	6,400± 700 scf	

Potential emissions:

52,000 scf sent to flare + 5,400 scf from vented tank = 57,000 scf methane

Appalachian Completion 3 Data Report

Well information
Company: AP-B

Surface Equipment Configuration
The entire flowback went from the well, through a temporary separator operated at a pressure of 100 psig. The liquids from the temporary separator went to a vented flowback tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. When gas was first produced from the separator, it was vented for a period of 75 minutes. After this initial venting, the gas was sent to a flare. Flaring continued until the end of the completion. The entire flowback lasted 12.5 hours.

Flowback timeline
Hours 0-3.5: flow to separator, no gas vented; liquid from the separator to a vented flowback tank.

Hours 3.5-4.75: Flowback to separator; gas vented; liquid from the separator to a vented flowback tank.

Hours 4.75-12.5: Flowback to separator; gas from the separator to flare; liquid from the separator to a vented flowback tank.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack: 91,500 ft^3

Data from completion report
Gas from separator (to vent): reported as 75 minutes of venting (no flow data)
Gas from separator (to flare): 199,000 scf

Gas Samples

Vented flowback tank gas samples

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
1 hour 42 min	Grab	N.D.
3 hours 0 min	Grab	66.48
3 hour 45 min	Grab	105.49*
4 hours 36 min	Grab	96.21
5 hours 2 min	Grab	103.32
5 hours 39 minutes	Grab	89.24
6 hours 0 minutes	Grab	66.41
6 hours 30 minutes	Grab	78.13
6 hours 44 minutes	Grab	81.28
7 hours 0 minutes	Grab	106.64*
7 hours 30 minutes	Grab	103.68*
9 hours 1 minute	Grab	45.30
11 hours 30 minutes	Grab	59.97

*methane composition was based on injection of a prescribed volume of gas, and detector response was calibrated based on this known volume; so although volume percentages greater than 100 are not physically possible, they are a part of the dataset; correcting these values to 100% was not done, since it would introduce bias into the dataset.

Emission calculations

Emissions measured through temporary stack during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Appalachian Completion 3 found in the study database. The data are summarized in Figure AP3-1. Total gas flow data were lost after hour 4, but the flow had stabilized and was extrapolated for the remaining hours of the completion.

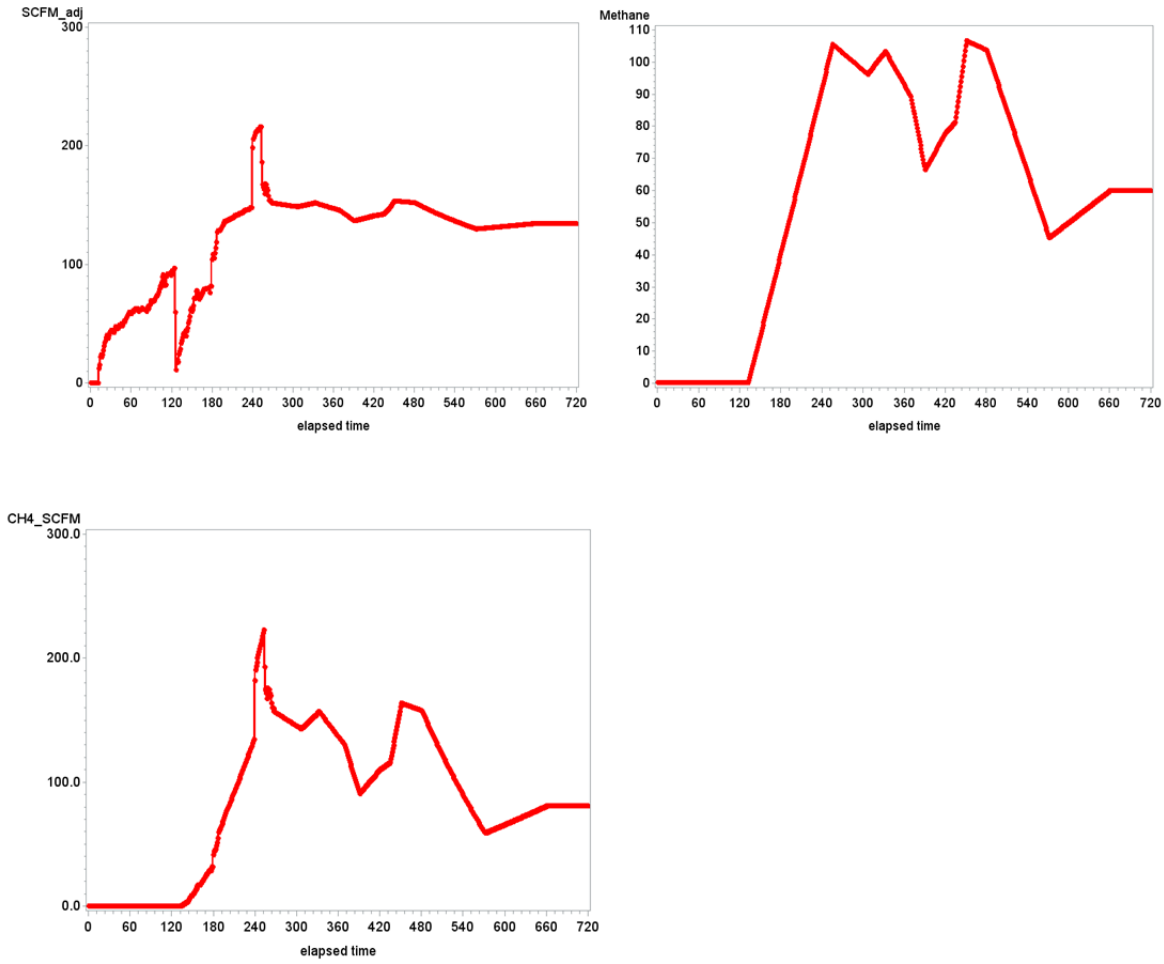
Emissions estimate = 63,500 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 6,350
Combined uncertainty = ± 6,350

Figure AP-3 Flowback into vented tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 91,500 ft^3 over 12.5 hr
Cumulative total methane: 63,500 scf over 12.5 hr



Emissions from gas sent to flare:
A total of 199,000 scf of gas was sent to the flare. An estimate of methane sent to the flare would be to assume that the gas, for the entire period, was the composition of gas that had the highest percentage of methane of the samples collected from the same well pad (100%)

199,000 scf * 1.00 mol fraction methane = 199,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

199,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 4,000 scf.

Emissions from gas vented from separator:
Flow rate was not reported for the venting from the separator, so the flow rate was assumed to be equal to the flow rate at which gas was sent to the flare immediately after the venting (31,000 scf per hour). Gas composition was assumed to be 100% methane.

1.25 hours * 31,000 scf per hour = 39,000 scf

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to vented tank	63,500 ± 6350 scf	
Emissions vented from separator		40,000
Emissions from flare		4,000 scf
Total (based on centerline gas velocity measurements)	108,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	95,000 ± 5000 scf	

Potential emissions:

199,000 scf sent to flare + 40,000 scf vented from separator + 51,000 scf from vented tank = 390,000 scf methane

Addendum to Appalachian Completion 3

Sampling was performed downwind of this completion. This was the only completion that had downwind sampling that had multiple sources on site. The Table below provides hour by hour emissions for this completion from each of the sources.

Time	**Individual source and total emission rates on well site (scf methane for the time period)**				**Emission rate for the time period (scf/m)**
	Vented tank	**Separator vent**	**Flare***	**Total**	
0600-0700	4	0	0	4	0.1
0700-0800	8	0	0	8	0.1
0800-0900	717	0	0	717	12
0900-1000	5,546	15,600	0	21,100	350
1000-1100	10,068	23,440	7,810*.02 = 150	34,000	560
1100-1200	8,865	0	31,250*.02 = 620	9,500	160
1200-1300	6,532	0	32,300*.02 = 650	7,200	120
1300-1400	8,601	0	25,600*.02 = 510	9,100	150
1400-1500	7,348	0	9,400*.02 = 190	7,500	125
1500-1600	4,101	0	5,200*.02 = 100	4,200	70
1600-1700	4,384	0	27,000*.02 = 540	4,900	82
1700-1800	4,842	0	31,700*.02 = 630	5,400	90
1800-1830	2,502	0	18,600*.02 = 370	2,900	97

*methane flow to flare multiplied by fraction uncombusted (0.02) yields emissions

Appalachian Completion 4 Data Report

Well information
Company: AP-C

Surface Equipment Configuration
Initial flowback went to a vented tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis.

After the initial period, the flow was sent to a separator. Gas from the separator was sent to sales. Liquid from the separator was sent to the same vented flowback tank as the initial flow. Flow rates of gases vented from the liquids continued to be measured through the temporary stacks and grab samples were taken for composition analysis. The completion lasted 339 hours.

Flowback timeline
Hours 0-339: Flow to vented flowback tank

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on vented tank: 2,697,000 scf

Gas Samples

Vented tank gas samples

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
2 hours 35 min	Grab	2.27
3 hours 36 min	Grab	14.77
3 hours 38 min	Grab	29.96
4 hours 43 min	Grab	29.96
5 hours 44 min	Grab	47.92
6 hours 25 min	Grab	72.42
6 hours 41 min	Grab	73.63
7 hours 45 min	Grab	81.57
8 hours 36 min	Grab	84.46
8 hours 41 min	Grab	89.77
25 hours 11 min	Grab	2.93
27 hours 13 min	Grab	69.44
28 hours 15 min	Grab	92.16
28 hours 28 min	Grab	94.30
28 hours 34 min	Grab	68.10
30 hours 27 min	Grab	61.98
32 hours 28 min	Grab	81.34
49 hours 14 min	Grab	70.52
51 hours 32 min	Grab	86.32
53 hours 33 min	Grab	87.37
55 hours 5 min	Grab	86.48
56 hours 28 min	Grab	78.70
72 hours 56 min	Grab	55.89
75 hours 07 min	Grab	40.94
77 hours 04 min	Grab	38.76
79 hours 02 min	Grab	48.40
80 hours 48 min	Grab	33.28
96 hours 44 min	Grab	22.18
98 hours 19 min	Grab	18.65
171 hours 04 min	Grab	55.50
171 hours 40 min	Grab	16.26
174 hours 25 min	Grab	17.97
175 hours 21 min	Grab	47.73
176 hours 10 min	Grab	21.77
176 hours 35 min	Grab	61.98
177 hours 17 min	Grab	36.70
219 hours 35 min	Grab	23.18
222 hours 25 min	Grab	10.24
224 hours 15 min	Grab	16.92
241 hours 15 min	Grab	6.39
243 hours 15 min	Grab	19.38

245 hours 30 min	Grab	23.93
247 hours 25 min	Grab	16.42
265 hours 10 min	Grab	3.79
267 hours 00 min	Grab	4.42
266 hours 55 min	Grab	3.12
268 hours 55 min	Grab	0.82

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Appalachian Completion 4 found in the study database. The data are summarized in Figure AP4-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Appalachian Completion 4 found in the study database.

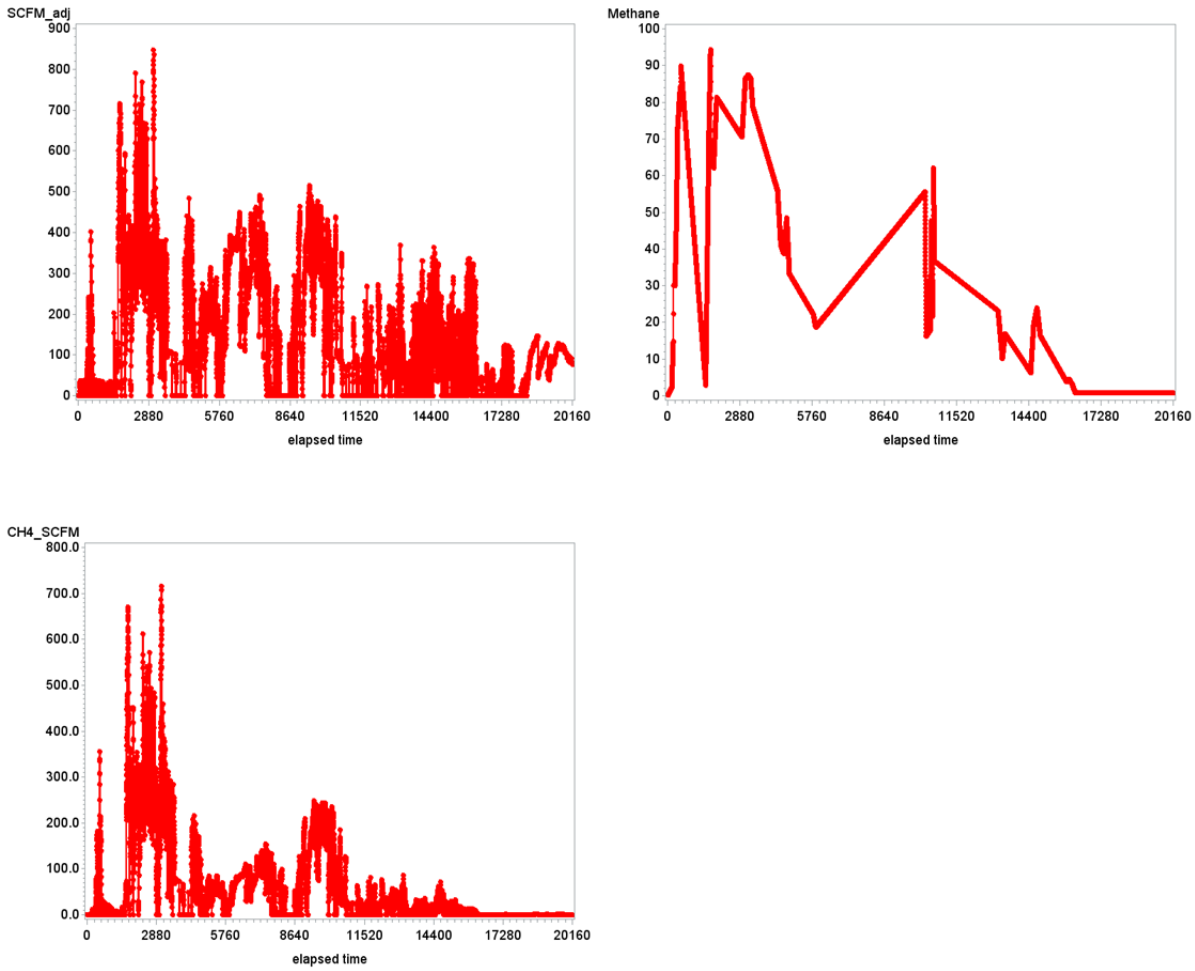
Emissions estimate = 1,100,000 ± 300,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 110,000
Combined uncertainty = ± 320,000

Figure AP4-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 2,697,000 ft^3 over 20,353 minutes (339.2 hours)
Cumulative total methane: 1,100,000 ft^3 over 20,353 minutes (339.2 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [803,000 – 1,426,000]



Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to vented tank	1,100,000 ± 320,000 scf	
Total (based on centerline gas velocity measurements)	1,100,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	880,000 ± 300,000 scf	

Potential emissions:

54,000,000 scf sent to sales + 880,000 scf from vented tank = 54,880,000 scf methane

Appalachian Completion 5 Data Report

Well information
Company: AP-C

Surface Equipment Configuration and Flowback timeline
Initial flowback went to a vented tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. It was originally intended that the initial completion flowback would go entirely to the vented tank, however, since some of the initial flowback had high gas loadings, some of this flow was diverted to a separator, with gas to sales and liquid (and possibly some gas) to a flowback tank without measurement equipment.

After the initial period, the flow was sent to a separator. Gas from the separator was sent to sales. Liquid from the separator was sent to the same vented flowback tank as the initial flow. Flow rates of gases vented from the liquids continued to be measured through the temporary stacks and grab samples were taken for composition analysis. This flow was intermittent, as the choke would periodically close due to ice formation. When this occurred, the well was shut in and ice cleared; then flow resumed. The total length of the completion was 9.5 days (228 hours). Due to the intermittent nature of the flow and the uncertainty in duration of the completion, the unmeasured flow during the initial flowback, and the opportunity to measure several other completions, the Study Team removed equipment after 2 days of sampling during one of the well shut-ins.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on vented tank during 2 days of measurements: 99,000 scf

Estimated total flow: Based on a very rough approximation of the unmeasured flow during the initial phases of the completion and an extrapolation of the flow for the final 7 days of the completion, a total gas volume was estimated to be 600,000 scf, based on centerline velocity of the gas. The ratio of methane to total gas (0.4) was assumed to be the same as for Appalachian Completion 4, which showed similar characteristics and had the same owner. This leads to an estimate of methane emissions of 240,000 scf. An error bound of at least 120,000 scf (50%) is appropriate.

Because of the significant uncertainties associated with this estimate, the data from this completion were not used in establishing average values for methane emissions from well completions, however, the estimate would not significantly change the average emissions for well completions in the Appalachian region.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to vented tank		240,000 ± 120,000 scf
Total (based on centerline gas velocity measurements)	240,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	190,000 scf	

Potential emissions:

48,000,000 scf sent to sales + 190,000 scf from vented tank = 48,200,000 scf methane

Gulf Coast Completion 1 Data Report

Well information
Company: GC-A

Surface Equipment Configuration
Initial flowback went to an open-top tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Initial flowback lasted for 4 hours.

After 4 hours the flow was sent to a high pressure separator. Gas from the high pressure separator (443-545 psig; Temp = 83-123°F, with temperature increasing as completion progressed) was sent to a flare. Water from the high pressure separator was sent to a vented water flowback tank that was equipped with a temporary stack. Hydrocarbon liquids from the high pressure separator were sent to a low pressure separator (84-103 psig, hours 5-28; 46-60 psig, hours 29-75; Temp = 74-107°F). Gas from the low pressure separator was sent to a flare. Hydrocarbon liquids from the low pressure separator were sent to a vented oil flowback tank that was equipped with a temporary stack. Flow rates of gases vented from the oil and water flowback tanks through the temporary stacks were measured and grab samples were taken for composition analysis.

Flowback timeline
Hours 0-4: Flow to gas-buster in open top tank; during this period well choke was set at 8/64”

Hours 4-75: Flow sent to separator; gas from separators to flare and fluids sent to flowback tanks

Hour 75: Gas to sales; Flowback ended

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 2,300 scf
Total flow through temporary stack on hydrocarbon liquid flowback tank: 32,500 scf
Total gas flow through temporary stack on water flowback tank: 6,100 scf

Data from completion report
Gas from high pressure separator (to flare): 5,915,000 scf
Gas from low pressure separator (to flare): 494,000 scf
Gas from high and low pressure separators (to flare): 6,409,000 scf
Gas composition analysis**:** spot sample on third day of completion, taken from the high pressure separator, was 79.5 mol% methane

Total oil volume: 1594 standard barrels; all to flowback tank
Total water volume: 227 standard barrels; 65 STB to open top tank and 162 STB to water flowback tank.

Gas Samples

Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
0 hr 43 min	Grab	ND
1 hr 06 min	Grab	ND
1 hr 26 min	Grab	ND
1 hr 53 min	Grab	58.45%
2 hr 54 min	Grab	77.49%
3 hr 00 min	Grab	53.74%

Hydrocarbon liquid flowback tank gas samples (from low pressure separator at 50-100 psig)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
6 hr 00 min	Grab	10.29%
22 hr 54 min	Grab	9.11%
25 hr 23 min	Grab	7.77%
29 hr 59 min	Grab	7.49%
30 hr 01 min	Grab	5.22%
46 hr 51 min	Grab	5.82%
46 hr 54 min	Grab	5.98%
48 hr 50 min	Grab	10.22%
49 hr 08 min	2 hr 53 min	6.27%
51 hr 53 min	Grab	19.49%
52 hr 08 min	4 hr 0 min	0.69%
70 hr 45 min	Grab	14.57%

Water flowback tank gas samples (from high pressure separator at 500 psig)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
5 hr 11 min	Grab	13.22%
6 hr 03 min	Grab	12.81%
7 hr 30 min	4 hr 0 min	3.06%
22 hr 36 min	3 hr 12 min	1.19%
22 hr 48 min	Grab	14.83%
25 hr 26 min	Grab	20.47%
25 hr 50 min	3 hr 58 min	10.47%
30 hr 00 min	Grab	7.58%
46 hr 42 min	Grab	4.20%
46 hr 47 min	Grab	6.38%
48 hr 53 min	Grab	5.61%
51 hr 50 min	Grab	6.62%
70 hr 36 min	Grab	4.32%

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linearly interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. Grab sample compositions were used rather than time averaged samples because the grab samples were preferentially collected during periods of high flow, while the time averaged samples collected gas continuously. Samples collected during periods of positive, rather than zero gas flow, were deemed to be more representative of vented gas composition. These calculations are documented in the Excel spreadsheet for Gulf Coast Completion 1 found in the study database. The data are summarized in Figure GC1-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion 1 found in the study database.

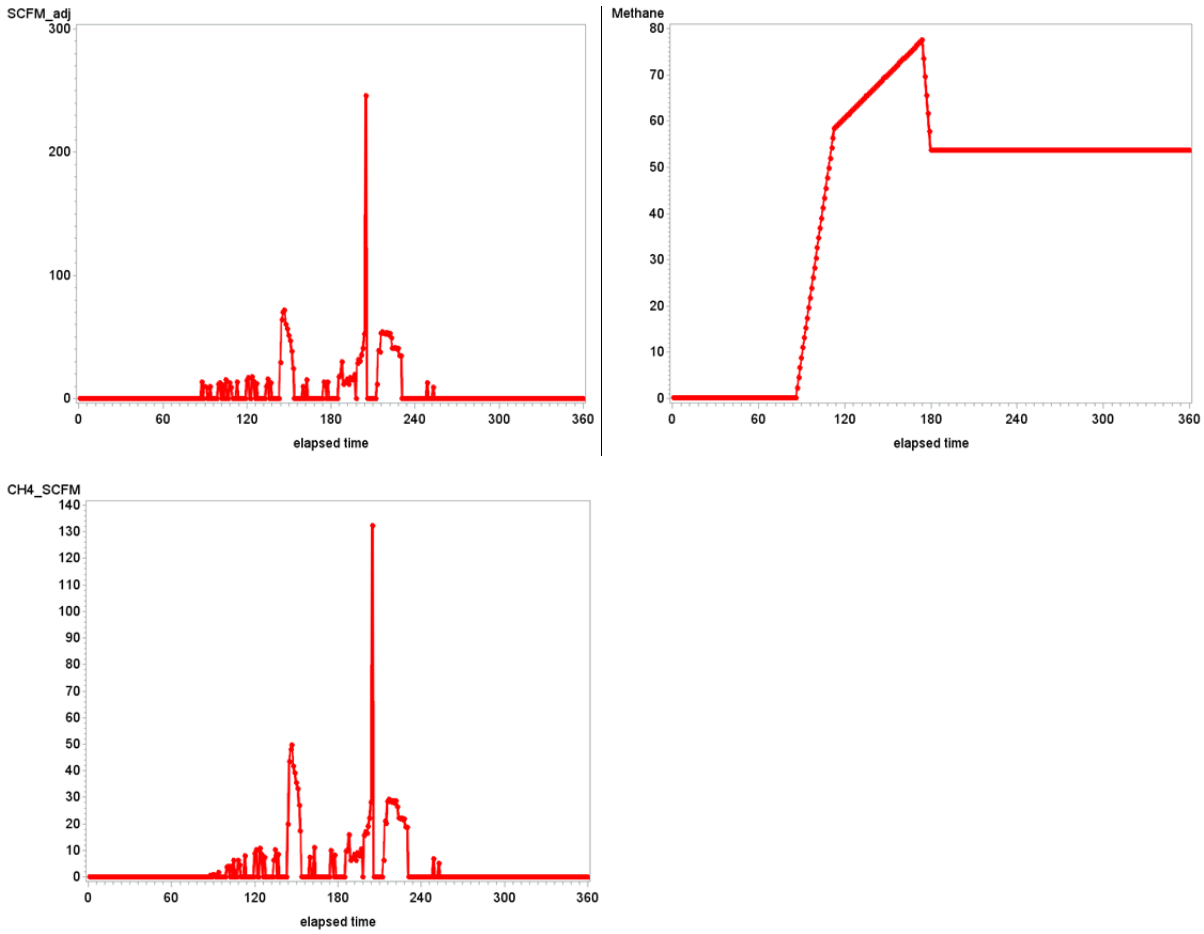
Emissions estimate = 1300 ± 120 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 130
Combined uncertainty = ± 180

Figure GC1-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 2,300 ft^3 over 253 minutes (4.2 hours)
Cumulative total methane: 1,300 ft^3 over 253 minutes (4.2 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [1,190 – 1,420]



Emissions from gas sent to flare:
A total of 6,409,000 scf of gas was sent to the flare. An upper bound on the amount of methane sent to the flare would be to assume that the gas, for the entire period, was 79.5% methane (the composition measured on day three, from the high pressure separator). This percentage of methane is an upper bound for two reasons. First, the flared gases are a combination of gas from the high and low pressure separators, and the gas from the high pressure separator would be expected to have a higher methane concentration than the gas from the low pressure separator. Second, the sample was taken near the end of the completion, when the methane concentration would be expected to be closer to a composition suitable for routing to sales:

6,409,000 scf * 0.795 mol fraction methane = 5,095,000 scf methane sent to flare

One alternative assumption would be that the percentage methane in the gas stream sent to the flare was equal to the average of the percentage methane observed in the final three samples during the initial flowback to the gasbuster (63% methane) and the methane measured after day 3 (79.5%)

6,409,000 scf * (0.63+0.795)/2 mol fraction methane = 4,566,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

4,566,000-5,095,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 91,000-102,000 scf. This is reported as 100,000 scf methane.

Emissions vented from hydrocarbon liquid flowback tank
Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linearly interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. Grab sample compositions were used rather than time averaged samples because the grab samples were preferentially collected during periods of high flow, while the time averaged samples collected gas continuously. Samples collected during periods of positive, rather than zero gas flow, were deemed to be more representative of vented gas composition. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 1 found in the study database. The data are summarized in Figure GC1-2.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet for Coast Completion 1 found in the study database.

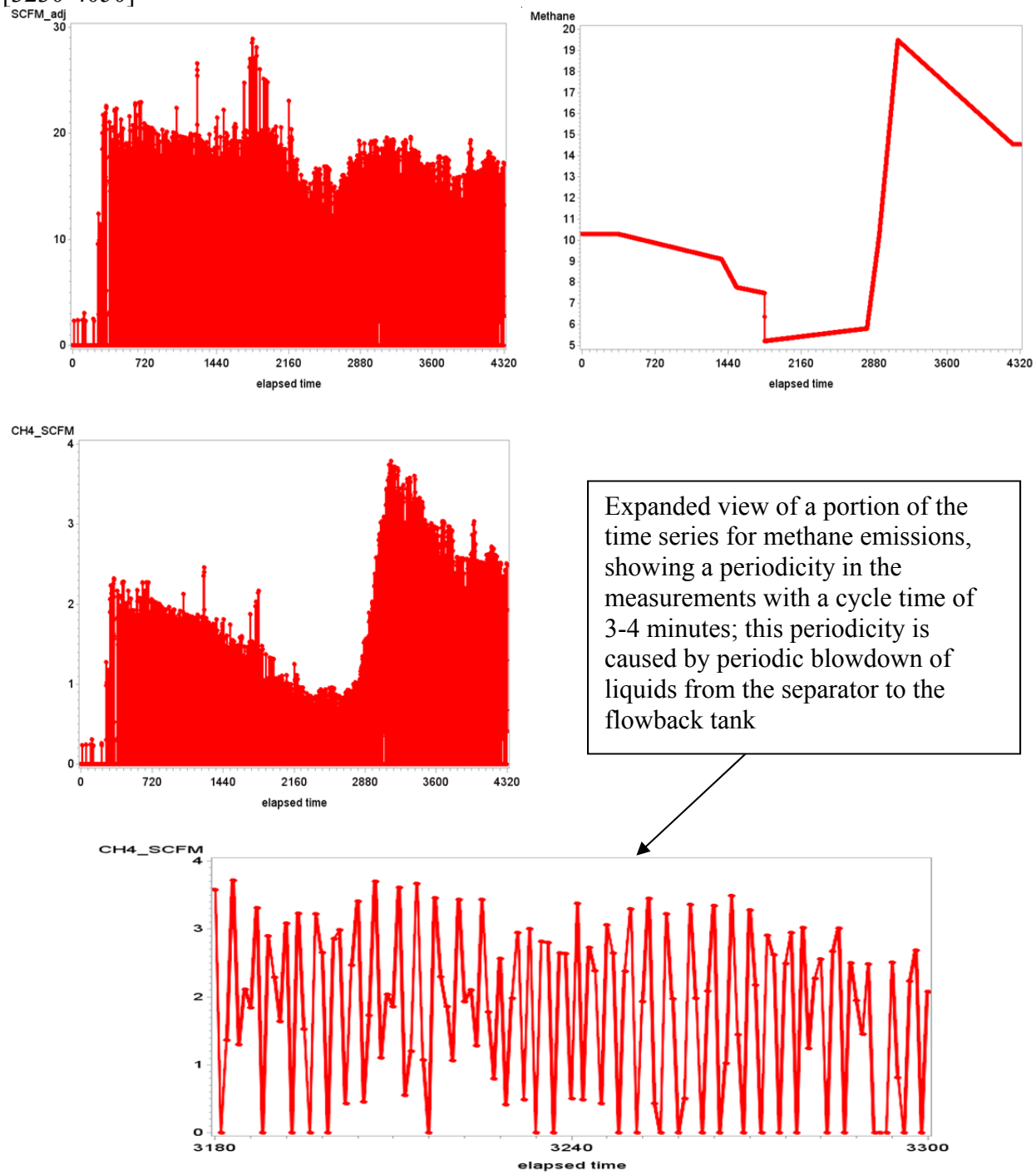
Emissions estimate = 3700 ± 400 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 370
Combined uncertainty = ± 550

Figure GC1-2 Flowback into oil tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 32,500 ft^3 over 4,494 minutes (75 hours)
Cumulative total methane: 3,700 ft^3 over 4,494 minutes (75 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [3230-4050]



Emissions vented from water flowback tank
Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linearly interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. Grab sample compositions were used rather than time averaged samples because the grab samples were preferentially collected during periods of high flow, while the time averaged samples collected gas continuously. Samples collected during periods of positive, rather than zero gas flow, were deemed to be more representative of vented gas composition. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 1 found in the study database. The data are summarized in Figure GC1-3.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion1 found in the study database.

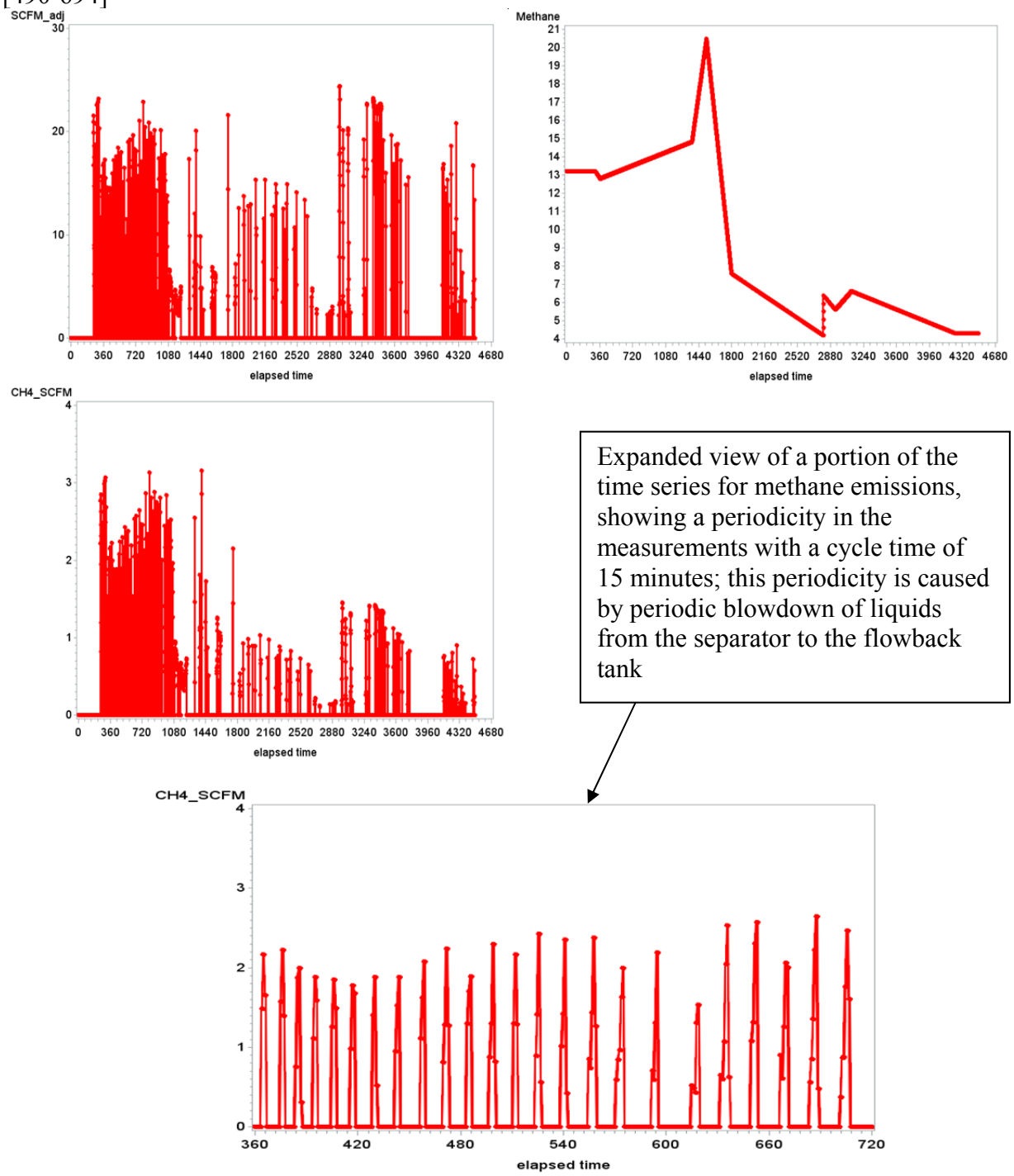
Emissions estimate = 600 ± 100 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 60
Combined uncertainty = ± 120

Figure GC1-3 Flowback into water tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 6,100 ft^3 over 4,494 minutes (75 hours)
Cumulative total methane: 600 ft^3 over 4,494 minutes (75 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [490-694]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the initial flowback period to the open top tank, gas flow of 2,300 and methane flow of 1300 ± 120 scf was measured. Since at all times during these initial 4 hours, the well pressure was more than double the pressure downstream of the choke, in the absence of direct measurements, emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=95°F (an average value during the initial 4 hours of flowback):
$$FRv\ (ft^3/hr) = 1.27*10^5 * \pi/4*(8/64in. * 0.0254\ m/in)^2 * (187.08*308)^{0.5}$$

Flow = 240 ft^3/hr at the sonic flow conditions (308K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 1500 scf/h. If this was assumed to be 80% methane, emissions of methane would be 1200 scf/h.

1200 scf/h*4 hr = 4800 scf

Emissions vented from hydrocarbon liquid flowback tank
The direct measurements of methane emissions from oil flowback tanks were compared to emissions estimated using methane content from the completion oil analysis. The analysis reported 0.268 wt% methane in an oil with a density of 5.16 lb/gal. This is equivalent to 0.58 lb/bbl of methane or 13 scf/bbl. These samples were taken from a separator run at 515 psia.

To scale these results to the solubility of methane in the oil emerging from the low pressure separator (which is sent to the vented oil flowback tank), the partial pressure of methane in the low pressure separator must be estimated. It is assumed that the ratio of partial pressures is equal to the ratio of absolute pressures. Scaling to 105 psia, which was the average pressure in the low pressure separator for hours 5-28, yields 2.6 scf/bbl (13 scf bbl * (105/515)); Scaling to 70 psia, which was the average pressure in the low pressure separator for hours 29-75, yields 1.8 scf/bbl

The estimated emissions based on these methane contents are:
396 bbl * 2.6 scf/bbl + (1594-396) bbl * 1.8 scf/bbl = 1030 scf + 2200 scf = 3200 scf

This compares well with the emission measurements of 3700 scf

Emissions vented from water flowback tank
The direct measurements of methane emissions from water flowback tanks were compared to emissions estimated using estimated methane solubility in water. Assuming a Henry's law constant of 4600 (MPa) (pure water, Kiepe, et al., 2003)

For a total pressure of 515 psia (3.5 MPa)

X_1= 3.5/4600 = 0.00076 mol fraction

If the gas in the separator is 80% methane, the mol fraction methane would be 0.0006. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 5 g mol of methane per bbl (0.0006*8830 g mol). To one significant figure, this is 4 scf per bbl of water.

This solubility estimate leads to an estimate of 600 scf for the completion. This is in excellent agreement with the emission measurement (600 scf).

Kiepe, J., Horstmann, S., Fisher, K., Gmehling, J., "Experimental Determination and Prediction of Gas Solubility Data for Methane + Water Solutions Containing Different Monovalent Electrolytes", *Industrial & Engineering Chemistry Research*, 42, 5392-5398 (2003).

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	1300 ± 180 scf	4800 scf
Emissions vented from hydrocarbon liquid flowback tank	3700 ± 550 scf	3200 scf
Emissions vented from water flowback tank	600 ± 120 scf	600 scf
Emissions from flare		100,000 scf
Total (based on centerline gas velocity measurements)	106,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	105,000 ± 600 scf	

Potential emissions:

5,000,000 scf sent to flare + 5,000 scf from open top tank and flowback tanks = 5,005,000 scf methane

Gulf Coast Completion 2 Data Report

Well information
Company: GC-A

Surface Equipment Configuration
Initial flowback went to an open-top tank. This tank was equipped, by the Study Team. with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Initial flowback lasted for approximately 4 hours.

After 4 hours the flow was sent to a high pressure separator. Gas from the high pressure separator (500-525 psig; Temp = 73-125°F, with temperature generally increasing as completion progressed) was sent to a flare. Water from the high pressure separator was sent to a vented water flowback tank that was equipped with a temporary stack. Hydrocarbon liquids from the high pressure separator were sent to a low pressure separator (124-128 psig, hours 5-25; 75 psig, hours 26-75; Temp = 70-123°F). Gas from the low pressure separator was sent to a flare. Hydrocarbon liquids from the low pressure separator were sent to a vented oil flowback tank that was equipped with a temporary stack. Flow rates of gases vented from the oil and water flowback tanks through the temporary stacks were measured and grab samples were taken for composition analysis.

Flowback timeline
Hours 0-4: Flow to gas-buster in open top tank; during this period well choke was set at 8/64”

Hours 5-75: Flow sent to separator; gas from separators to flare and fluids sent to frac tanks

Hour 76: Gas to sales; Flowback ended

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 3,000 scf
Total flow through temporary stack on hydrocarbon liquid frac tank: 50,000 scf
Total gas flow through temporary stack on water frac tank: 2,000 scf

Data from completion report
Gas from high pressure separator (to flare): 5,124,000 scf
Gas from low pressure separator (to flare): 466,000 scf
Gas from high and low pressure separators (to flare): 5,590,000 scf
Gas composition analysis**:** spot sample on third day of completion, taken from the high pressure separator, was 79.2 mol% methane

Total oil volume: 1323 standard barrels; all to flowback tank
Total water volume: 297 standard barrels; 104 STB to open top tank and 193 STB to flowback tank.

Gas Samples

Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
0 hr 58 min	Grab	ND
1 hr 31 min	Grab	ND
1 hr 56 min	Grab	4.71%
2 hr 29 min	Grab	64.03%
3 hr 06 min	Grab	5.82%

Hydrocarbon liquid flowback tank gas samples (from low pressure separator at 125 psig)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
5 hr 50 min	4 hr 0 min	9.16%
6 hr 05 min	Grab	19.38%
22 hr 38 min	3 hr 06 min	15.07%
23 hr 02 min	Grab	10.85%
25 hr 20 min	Grab	10.27%
25 hr 46 min	4 hr 13 min	12.65%
30 hr 03 min	4 hr 0 min	10.13%
30 hr 05 min	Grab	8.19%
46 hr 25 min	2 hr 52 min	7.29%
47 hr 12 min	Grab	9.85%
47 hr 17 min	Grab	8.34%
48 hr 45 min	Grab	6.31%
49 hr 18 min	2 hr 53 min	8.46%
52 hr 11 min	4 hr 0 min	9.01%
53 hr 56 min	Grab	5.87%
70 hr 45 min	Grab	7.94%

Water flowback tank gas samples (from high pressure separator at 500 psig)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
5 hr 14 min	Grab	32.17%
6 hr 06 min	Grab	9.21%
23 hr 08 min	Grab	12.31%
25 hr 22 min	Grab	9.29%
47 hr 20 min	Grab	5.59%
47 hr 23 min	Grab	6.24%
52 hr 00 min	Grab	5.38%
70 hr 38 min	Grab	3.61%

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linearly interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 2 found in the study database. The data are summarized in Figure GC2-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion 2 found in the study database.

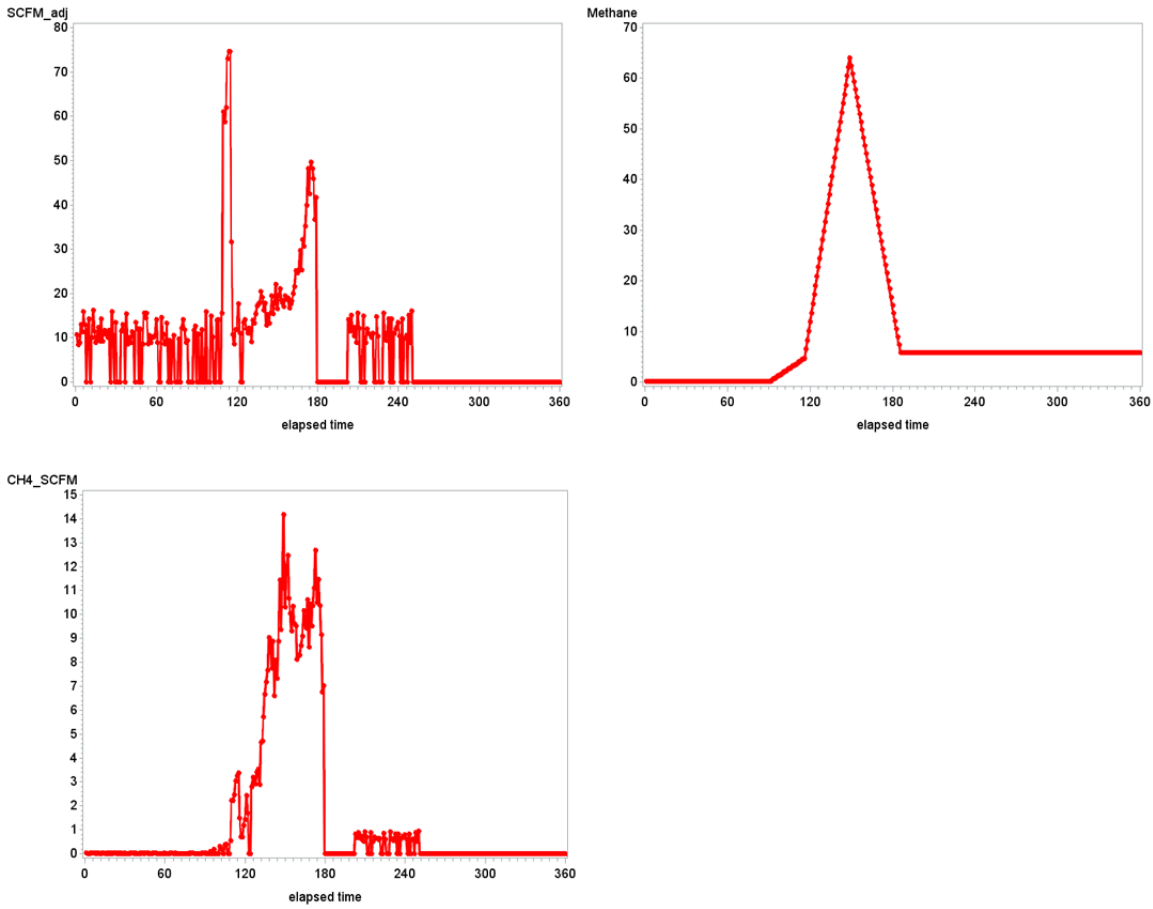
Emissions estimate = 500 ± 400 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 50
Combined uncertainty = ± 400

Figure GC2-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 3000 ft^3 over 250 minutes (4.2 hours)
Cumulative total methane: 520 ft^3 over 250 minutes (4.2 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [99-1013]



Emissions from gas sent to flare:
A total of 5,590,000 scf of gas was sent to the flare. An upper bound on the amount of methane sent to the flare would be to assume that the gas, for the entire period, was 79.2% methane (the composition measured on day three, from the high pressure separator). This percentage of methane is an upper bound for two reasons. First, the flared gases are a combination of gas from the high and low pressure separators, and the gas from the high pressure separator would be expected to have a higher methane concentration than the gas from the low pressure separator. Second, the sample was taken near the end of the completion, when the methane concentration would be expected to be closer to a composition suitable for routing to sales:

5,590,000 scf * 0.792 mol fraction methane = 4,427,000 scf methane sent to flare

One alternative assumption would be that the percentage methane in the gas stream sent to the flare was equal to the average of the percentage methane observed in the highest of the samples during the initial flowback to the gasbuster (64% methane) and the methane measured after day 3 (79.2%)

5,590,000 scf * (0.64+0.795)/2 mol fraction methane = 4,000,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

4,000,000-4,427,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 80,000-89,000 scf. This is reported as 85,000 scf methane.

Emissions vented from hydrocarbon liquid flowback tank
Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linearly interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. Grab sample compositions were used rather than time averaged samples because the grab samples were preferentially collected during periods of high flow, while the time averaged samples collected gas continuously. Samples collected during periods of positive, rather than zero gas flow, were deemed to be more representative of vented gas composition. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 2 found in the study database. The data are summarized in Figure GC2-2.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion 2 found in the study database.

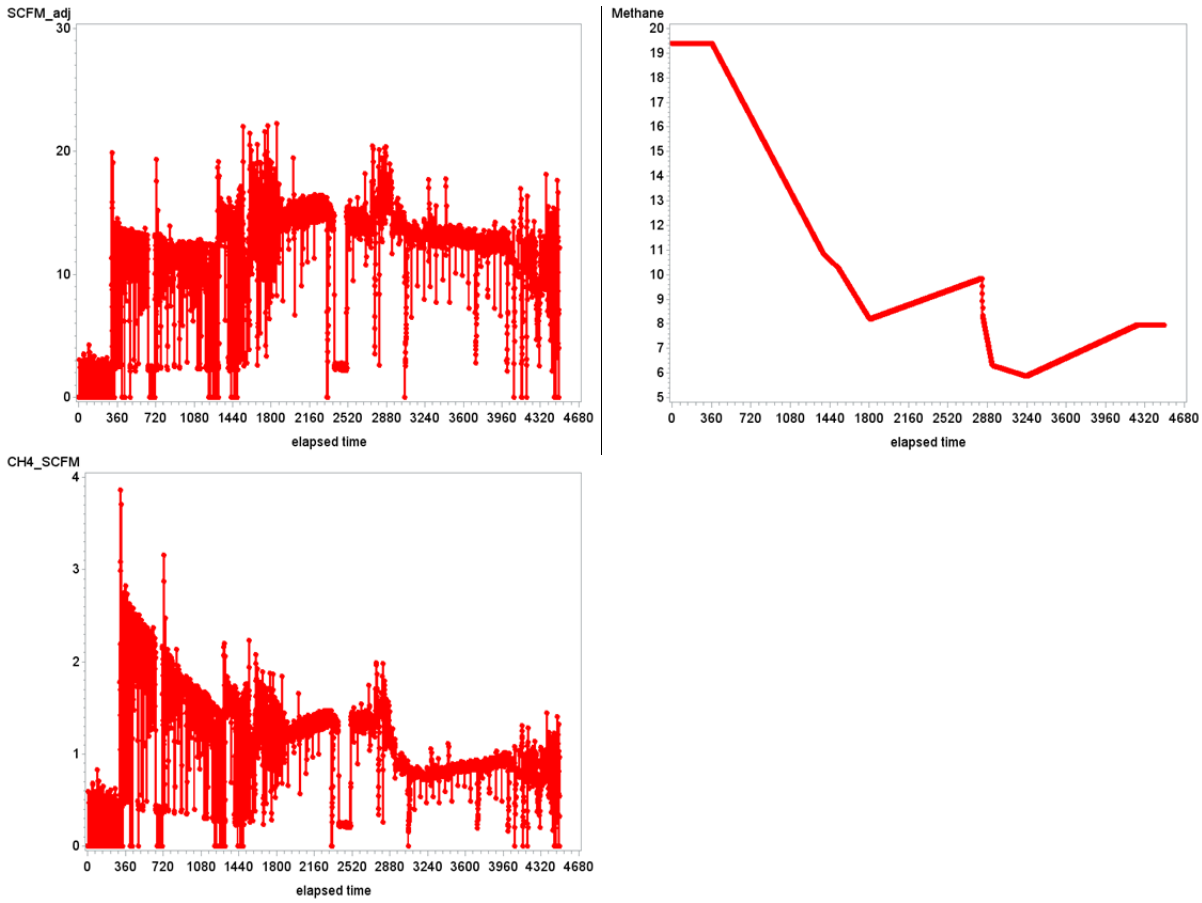
Emissions estimate = 4800 ± 800 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 480
Combined uncertainty = ± 900

Figure GC2-2 Flowback into oil tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 50,000 ft^3 over 4,494 minutes (75 hours)
Cumulative total methane: 4,770 ft^3 over 4,494 minutes (75 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [3,900-5,540]



Emissions vented from water flowback tank
Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linearly interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 2 found in the study database. The data are summarized in Figure GC2-3.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion 2 found in the study database.

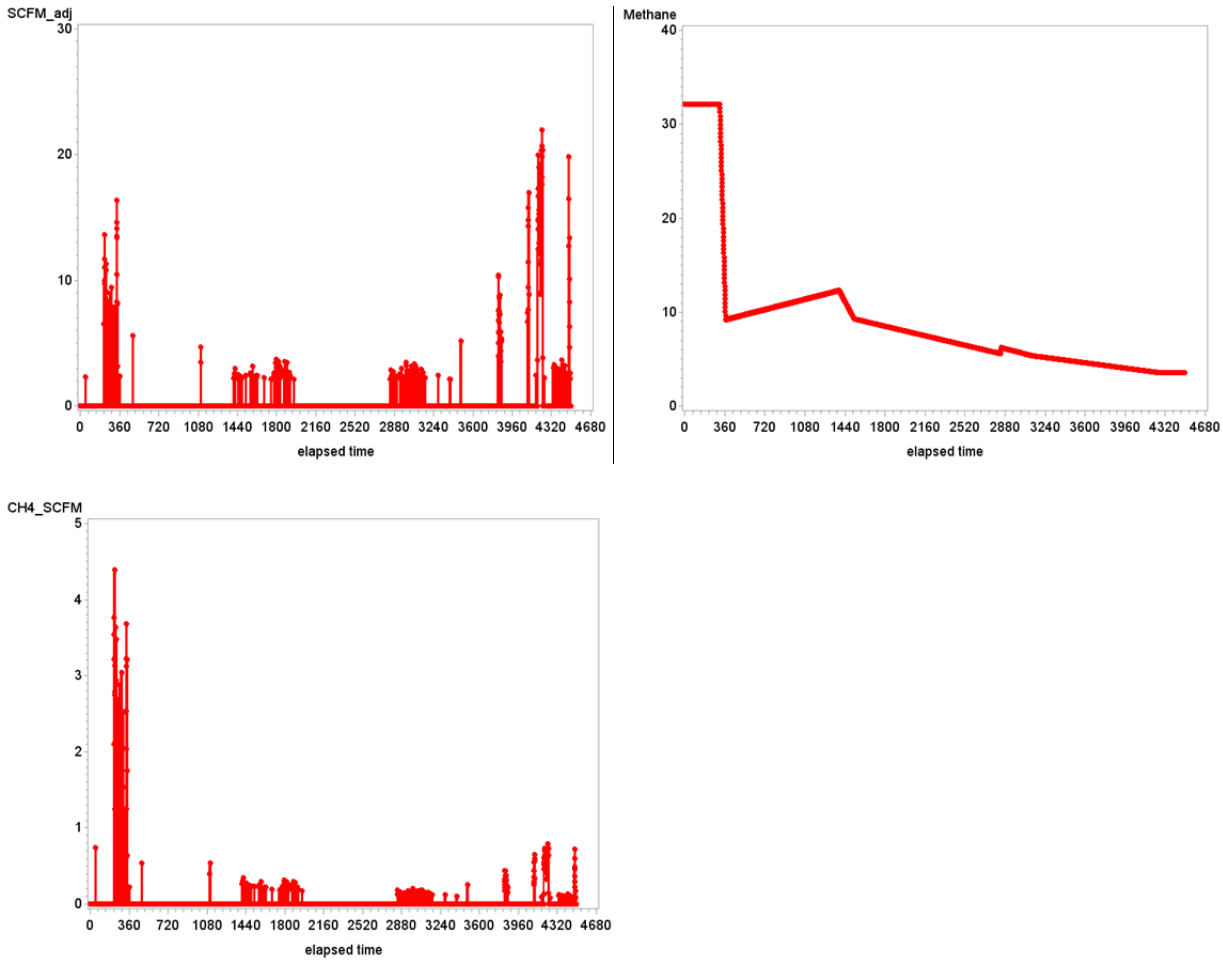
$$\text{Emissions estimate} = 200 \pm 100 \text{ scf}$$

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

$$\text{Flow rate uncertainty} = \pm 20$$
$$\text{Combined uncertainty} = \pm 100$$

Figure GC2-3 Flowback into water tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 2,000 ft^3 over 4,494 minutes (75 hours)
Cumulative total methane: 200 ft^3 over 4,494 minutes (75 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [75-222]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the initial flowback period to the open top tank, gas flow of 3,000 and methane flow of 500 ± 400 scf was measured. Since at all times during these initial 4 hours, the well pressure was more than double the pressure downstream of the choke, in the absence of direct measurements, emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=105°F (an average value during the initial 4 hours of flowback):
$$FRv\ (ft^3/hr) = 1.27*10^5 * \pi/4*(8/64in. * 0.0254\ m/in)^2 * (187.08*313)^{0.5}$$

Flow = 242 ft^3/hr at the sonic flow conditions (313K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 1600 scf/h. If this was assumed to be 80% methane, emissions of methane would be 1300 scf/h.

1300 scf/h*4 hr = 5200 scf

Emissions vented from hydrocarbon liquid flowback tank
The direct measurements of methane emissions from oil flowback tanks were compared to emissions estimated using methane content from the completion oil analysis. The analysis reported 3.5 wt% methane in an oil with a density of 4.27 lb/gal. This is equivalent to 6.3 lb/bbl of methane or 150 scf/bbl. These samples were taken from a separator run at 515 psia.

To scale these results to the solubility of methane in the oil emerging from the low pressure separator (which is sent to the vented oil flowback tank), the partial pressure of methane in the low pressure separator must be estimated. It is assumed that the ratio of partial pressures is equal to the ratio of absolute pressures. Scaling to 125 psig, which was the average pressure in the low pressure separator for hours 5-25, yields 41 scf/bbl (150 scf bbl * (140/515)); Scaling to 75 psig, which was the average pressure in the low pressure separator for hours 26-76, yields 26 scf/bbl

The estimated emissions based on these methane contents are:
163 bbl * 41 scf/bbl + (1323-160) bbl * 26 scf/bbl = 6683 scf + 30,200 scf = 37,000 scf

Emissions vented from water flowback tank

The direct measurements of methane emissions from water flowback tanks were compared to emissions estimated using estimated methane solubility in water. Assuming a Henry's law constant of 4600 (MPa) (pure water, Kiepe, et al., 2003)

For a total pressure of 515 psia (3.5 MPa)

X_1= 3.5/4600 = 0.00076 mol fraction

If the gas in the separator is 80% methane, the mol fraction methane would be 0.0006. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 5 g mol of methane per bbl (0.0006*8830 g mol). To one significant figure, this is 4 scf per bbl of water.

This solubility estimate leads to an estimate of 800 scf for the completion. This is higher than the emission measurement (200 scf).

Kiepe, J., Horstmann, S., Fisher, K., Gmehling, J., "Experimental Determination and Prediction of Gas Solubility Data for Methane + Water Solutions Containing Different Monovalent Electrolytes", *Industrial & Engineering Chemistry Research*, 42, 5392-5398 (2003).

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	500 ± 400 scf	5200 scf
Emissions vented from hydrocarbon liquid flowback tank	4800 ± 800 scf	37,000 scf*
Emissions vented from water flowback tank	200 ± 100 scf	800 scf
Emissions from flare		85,000 scf
Total (based on centerline gas velocity measurements)	91,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	90,000 scf	

*this estimate is based on an oil analysis that had methane, ethane and propane concentrations higher than standard equilibrium solubility measurements would predict, suggesting entrained gas in the sample

Potential emissions:

4,200,000 scf sent to flare + 5,000 scf from open top tank and flowback tanks = 4,205,000 scf methane

Gulf Coast Completion 3 Data Report

Well information
Company: GC-B

Surface Equipment Configuration
Flowback went to a gas-buster tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Initial flowback lasted for 28 hours.

After 28 hours the flow was sent to a separator. Gas from the separator (189-1991 psig; mean = 985 psig; median = 1185 psig) was sent to a flare or to sales. Hydrocarbon liquids from the separator were sent to a flowback tank that was vented to a combustion device. Water from the separator was sent to a vented flowback tank. Gas from the separator was sent either to a flare or to sales.

Flowback timeline
Hours 0-28: Flow to gas-buster in open top tank; then, flow sent to separator; gas from separators to flare and vented fluids from hydrocarbon liquid flowback tanks sent to combustion device; vented gases from water flowback tank vented to atmosphere.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 130,000 scf

Data from completion report
Gas from pressure separator (to elevated flare with pilot): 10.022 million scf
Gas from pressure separator (to sales): 16.211 million scf

Total oil volume: 2395 standard barrels; to flowback tank with vented gas sent to combustion device
Total water volume: 6301 standard barrels; to flowback tank with vented gas

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
1 hr 34 min	Grab	41.35
5 hr 27 min	Grab	59.55
5 hr 30 min	Grab	62.72
22 hr 43 min	Grab	10.41%
22 hr 46 min	Grab	8.50%
25 hr 07 min	Grab	8.33%

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 3 found in the study database. The data are summarized in Figure GC3-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion 3 found in the study database.

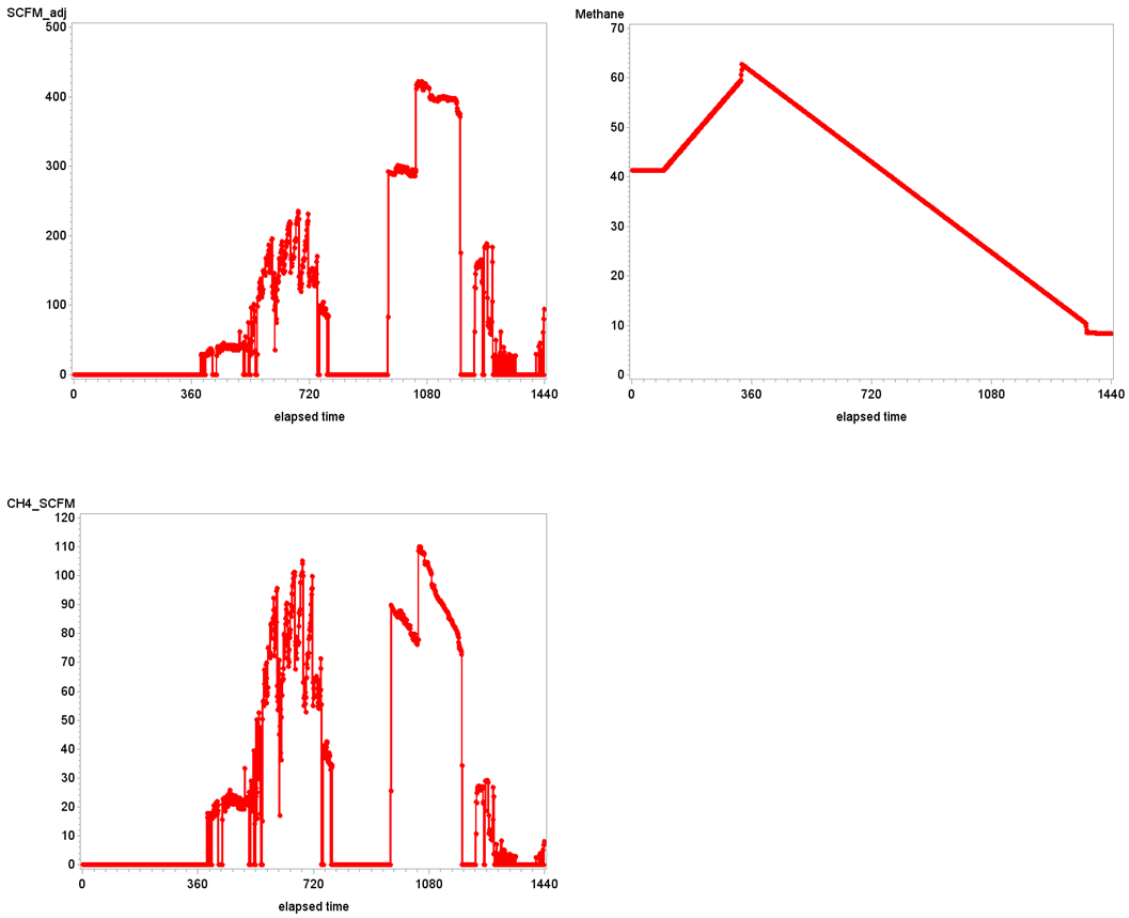
Emissions estimate = 40,000 ± 30,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 4,000
Combined uncertainty = ± 30,000

Figure GC3-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 130,000 ft^3 over 1,684 minutes (28 hours)
Cumulative total methane: 40,000 ft^3 over 1,684 minutes (28 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [13,000 – 84,000]



Emissions from gas sent to flare:
A total of 10,022,000 scf of gas was sent to the flare. A gas composition of 74% methane was recorded for most of the period of the completion for the flow to the flare.

10,022,000 scf * 0.74 mol fraction methane = 7,400,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming 98% combustion efficiency for the flare)

7,400,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 150,000 scf.

Emissions vented from hydrocarbon liquid flowback tank and sent to combustor
No measurements of methane dissolved in the hydrocarbon liquids were available, so correlations developed by Vazquez and Beggs (1980) were used to estimate dissolved methane. These correlations estimate gas solubility in oil based on temperature, pressure, and oil composition, as characterized by API gravity.

$$Rs = (0.0178 * SG_x * P_i^{1.187}) \exp((23.931 * API) / (T_i + 460))$$

For API>30

R_s	Gas/Oil Ratio of liquid at pressure of interest (scf/BBL)
SG_x	Dissolved gas gravity at 100 psig (density ratio with air)
P_i	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
T_i	Temperature of initial condition (F)

Assuming that the separator operated at 1000 psia and a temperature of 100°F and that the API gravity of the oil was 58-60° leads to an estimate of total dissolved gases (R_s)of

R_s = 570 scf/bbl

At this pressure, it would be expected that no more than 50% of the dissolved gases would be methane, leading to an estimate of 300 scf/BBL

The total amount of vented methane would then be:

2395 BBL*300 scf/BBL = 0.7 million scf

700,000 scf sent to combustion * (1-0.98) fraction released assuming 98% combustion efficiency = 14,000 scf.

M. Vazquez and H.D. Beggs, Correlations for Fluid Physical Property Prediction, Journal of Petroleum Technology, June, 1980, 968-970.

Emissions vented from water flowback tank
Volatilization of methane from the water flowback tanks was estimated based on saeparator pressure and methane solubility in water. Assuming a Henry's law constant of 4600 (MPa) (pure water, Kiepe, et al., 2003)

For a total pressure of 1000 psia (7 MPa)

X_1= 7/4600 = 0.0015 mol fraction

If the gas in the separator is 80% methane, the mol fraction methane would be 0.0012. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 11 g mol of methane per bbl (0.0012*8830 g mol). To one significant figure, this is 9 scf per bbl of water.

9 scf/BBL * 6301 BBL = 60,000 scf

Kiepe, J., Horstmann, S., Fisher, K., Gmehling, J., "Experimental Determination and Prediction of Gas Solubility Data for Methane + Water Solutions Containing Different Monovalent Electrolytes", *Industrial & Engineering Chemistry Research*, 42, 5392-5398 (2003).

Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the initial flowback period to the open top tank, gas flow of 130,000 scf and methane flow of 40,000 ± 30,000 scf was measured. Since at all times during these initial 28 hours, the well pressure was more than double the pressure downstream of the choke, in the absence of direct measurements, emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=100°F, and a choke setting of 12/64" for hours 0-15 and 14/64 for hours 16-28:

$$FRv\ (ft^3/hr,\ hours\ 0\text{-}15) = 1.27*10^5 * \pi/4*(12/64in. * 0.0254\ m/in)^2 * (187.08*311)^{0.5}$$

Flow = 545 ft^3/hr at the sonic flow conditions (311K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 3700 scf/h. If this was assumed to be 74% methane, emissions of methane would be 2700 scf/h.

2700 scf/h*15 h = 41,000 scf for hours 0-15

$$FRv\ (ft^3/hr,\ hours\ 0\text{-}15) = 1.27*10^5 * \pi/4*(14/64in. * 0.0254\ m/in)^2 * (187.08*311)^{0.5}$$

Flow = 740 ft^3/hr at the sonic flow conditions (311K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 5000 scf/h. If this was assumed to be 74% methane, emissions of methane would be 3700 scf/h.

3700 scf/h*13 h = 48,000 scf for hours 16-28

Total estimated emissions = 90,000 scf

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	40,000 ± 30,000 scf	90,000 scf
Emissions vented and combusted from hydrocarbon liquid flowback tank		14,000 scf
Emissions vented from water flowback tank		60,000 scf
Emissions from flare		150,000 scf
Total (based on centerline gas velocity measurements)	264,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	260,000 ± 30,000 scf	

Potential emissions:

7,400,000 scf sent to flare + 12,000,000 scf sent to sales + 40,000 scf from open top tank and 2,000,000 from oil flowback tank + 60,000 from water flowback tank = 21,500,000 scf methane

Gulf Coast Completion 4 Data Report

Well information
Company: GC-B

Surface Equipment Configuration
Flowback went to a gas-buster tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. After initial flowback, the flow was sent to a separator. Gas from the separator (226-1284 psig; mean = 991 psig; median = 1184 psig) was sent to a flare or to sales. Hydrocarbon liquids from the separator were sent to a flowback tank that was vented to a combustion device. Water from the separator was sent to a vented flowback tank. Gas from the separator was sent either to a flare or to sales.

Flowback timeline
Hours 0-28: Flow to gas-buster in open top tank; then flow sent to separator; gas from separators to flare and vented fluids from hydrocarbon liquid flowback tanks sent to combustion device; vented gases from water flowback tank vented to atmosphere.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 60,000 scf

Data from completion report
Gas from pressure separator (to elevated flare with pilot): 9.055 million scf
Gas from pressure separator (to sales): 15.238 million scf

Total oil volume: 1682 standard barrels; to flowback tank, vented gas sent to combustion device
Total water volume: 8162 standard barrels; to flowback tank with vented gas

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
1 hour 38 min	Grab	34.25
5 hours 13 min	Grab	35.62
5 hours 34 min	Grab	39.67
22 hours 30 min	Grab	6.66
22 hours 36 min	Grab	8.78
25 hours 02 min	Grab	10.09

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 4 found in the study database. The data are summarized in Figure GC4-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion 4 found in the study database.

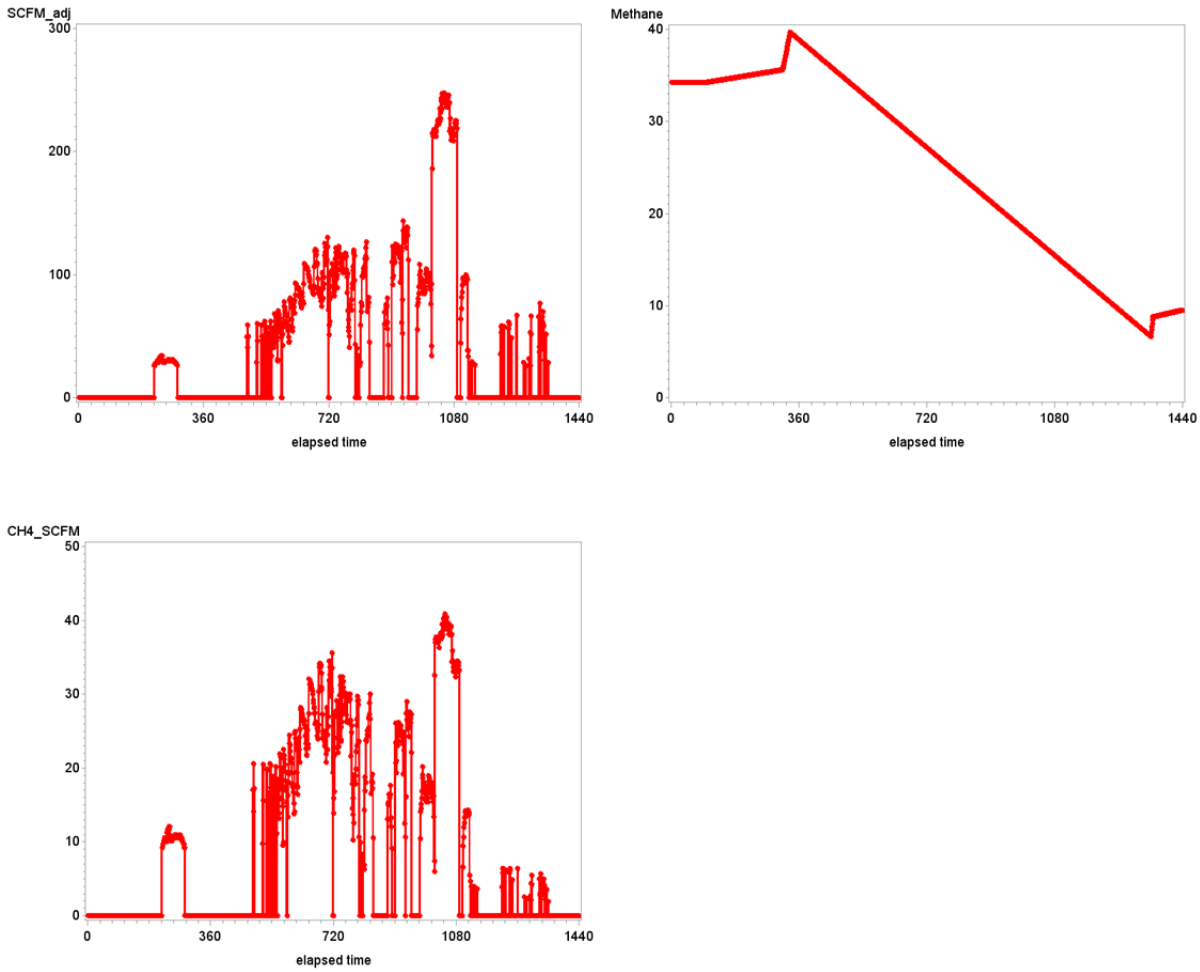
Emissions estimate = 13,000 ± 10,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 1,300
Combined uncertainty = ± 10,000

Figure GC4-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 60,000 ft^3 over 1,678 minutes (28 hours)
Cumulative total methane: 13,000 ft^3 over 1,678 minutes (28 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [4,550 – 23,500]



Emissions from gas sent to flare:
A total of 9,055,000 scf of gas was sent to the flare. This flow went on for a total of 184 hours, during which time, gas composition increased steadily from 35-60% methane. An average gas composition of 48% methane is assumed.

9,055,000 scf * 0.48 mol fraction methane = 4,300,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming 98% combustion efficiency for the flare)

4,300,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 90,000 scf.

Emissions vented from hydrocarbon liquid flowback tank and sent to combustor
No measurements of methane dissolved in the hydrocarbon liquids were available, so correlations developed by Vazquez and Beggs (1980) were used to estimate dissolved methane. These correlations estimate gas solubility in oil based on temperature, pressure, and oil composition, as characterized by API gravity.

$$Rs = (0.0178 * SG_x * P_i^{1.187}) \exp((23.931 * API) / (T_i + 460))$$

For API>30

R_s	Gas/Oil Ratio of liquid at pressure of interest (scf/BBL)
SG_x	Dissolved gas gravity at 100 psig (density ratio with air)
P_i	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
T_i	Temperature of initial condition (F)

Assuming that the separator operated at 1000 psia and a temperature of 100°F and that the API gravity of the oil was 58-60° leads to an estimate of total dissolved gases (R_s)of

R_s = 570 scf/bbl

At this pressure, it would be expected that no more than 50% of the dissolved gases would be methane, leading to an estimate of 300 scf/BBL

The total amount of vented methane would then be:

1682 BBL*300 scf/BBL = 500,000 scf

500,000 scf sent to combustion * (1-0.98) fraction released assuming 98% combustion efficiency = 20,000 scf.

M. Vazquez and H.D. Beggs, Correlations for Fluid Physical Property Prediction, Journal of Petroleum Technology, June, 1980, 968-970.

Emissions vented from water flowback tank
Volatilization of methane from the water flowback tanks was estimated based on saeparator pressure and methane solubility in water. Assuming a Henry's law constant of 4600 (MPa) (pure water, Kiepe, et al., 2003)

For a total pressure of 1000 psia (7 MPa)

X_1= 7/4600 = 0.0015 mol fraction

If the gas in the separator is 60% methane, the mol fraction methane would be 0.0009. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 8 g mol of methane per bbl (0.0009*8830 g mol). To one significant figure, this is 7 scf per bbl of water.

7 scf/BBL * 8162 BBL = 60,000 scf

Kiepe, J., Horstmann, S., Fisher, K., Gmehling, J., "Experimental Determination and Prediction of Gas Solubility Data for Methane + Water Solutions Containing Different Monovalent Electrolytes", *Industrial & Engineering Chemistry Research*, 42, 5392-5398 (2003).

Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the initial flowback period to the open top tank, gas flow of 60,000 scf and methane flow of 13,000 ± 10,000 scf was measured. Since at all times during these initial 28 hours, the well pressure was more than double the pressure downstream of the choke, in the absence of direct measurements, emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=130°F (an average value for the first 28 hours of flow), and a choke setting of 12/64" for hours 0-16 and 14/64 for hours 17-28:

$$FRv\ (ft^3/hr,\ hours\ 0\text{-}12) = 1.27*10^5 * \pi/4*(12/64in. * 0.0254\ m/in)^2 * (187.08*328)^{0.5}$$

Flow = 560 ft^3/hr at the sonic flow conditions (328K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 3300 scf/h. If this was assumed to be 48% methane, emissions of methane would be 1600 scf/h.

1600 scf/h*16 h = 26,000 scf for hours 0-16

$$FRv\ (ft^3/hr,\ hours\ 0\text{-}15) = 1.27*10^5 * \pi/4*(14/64in. * 0.0254\ m/in)^2 * (187.08*328)^{0.5}$$

Flow = 760 ft^3/hr at the sonic flow conditions (328K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 4500 scf/h. If this was assumed to be 48% methane, emissions of methane would be 2200 scf/h.

2200 scf/h*12 h = 26,000 scf for hours 17-28

Total estimated emissions = 50,000 scf

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	13,000 ± 10,000 scf	50,000 scf
Emissions vented and combusted from hydrocarbon liquid flowback tank		20,000 scf
Emissions vented from water flowback tank		60,000 scf
Emissions from flare		90,000 scf
Total (based on centerline gas velocity measurements)	180,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	180,000 ± 8,000 scf	

Potential emissions:

4,300,000 scf sent to flare + 7,600,000 scf sent to sales + 13,000 scf from open top tank and 1,000,000 from oil flowback tank + 60,000 from water flowback tank = 13,000,000 scf methane

Gulf Coast Completion 5 Data Report

Well information
Company: GC-C

Surface Equipment Configuration
Flowback went to a gas-buster tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 14 hours.

Flowback timeline
Hours 0-14: Flow to gas-buster in open top tank;

Routine sampling was conducted for approximately the first 40% of the completion; at that point (409 minutes from the start of the completion), a short surge in flow caused the temporary stack to be displaced; the completion continued for another 9 hours; the data from the first 40% of the completion was used to estimate the emissions for the remainer of the flowback.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 68,000 scf (includes 27,300 scf from first 409 minutes (40%) of completion)

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
1 hour 53 min	Grab	80.92
2 hour 20 min	Grab	78.49
2 hour 53 min	Grab	45.87
3 hour 23 min	Grab	48.34
3 hour 53 min	Grab	31.96

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Gulf Coast Completion 5 found in the study database. The data are summarized in Figure GC5-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion.These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Gulf Coast Completion 5 found in the study database.

Emissions estimate for first 409 minutes = 9060 scf

Emissions estimate accounting for all measured flows = 14,000 ± 7,000 scf

Estimated emissions over entire completion

Total gas flow rate and gas composition measurements from the last hours of measurements were relatively stable and were used to extrapolate data for the remainer of the flowback. Total gas flow rates were averaged and standard deviations were determined for one hour periods. Gas compositions over the final three samples, were averaged with standard deviations determined. Random draws for flow rate and gas composition, based on the statistics of the data from the final three hours of sampling, were used for the remaining period of sampling. The extrapolated data are shown in Figure GC5-2. Based on this approach, the total emissions were estimated 21,600 scf methane, with an uncertainty bound of 50% of the estimated flow, based on the uncertainties in the emission estimate during the initial flow.:

Estimated total emissions = 21,600 ± 12,000 scf.

Figure GC5-1 Flowback into open-top gas buster tank and measured by flow through temporary stack; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 43,000 ft^3 over 409 minutes
Cumulative total methane: 14,000 ft^3 over 409 minutes

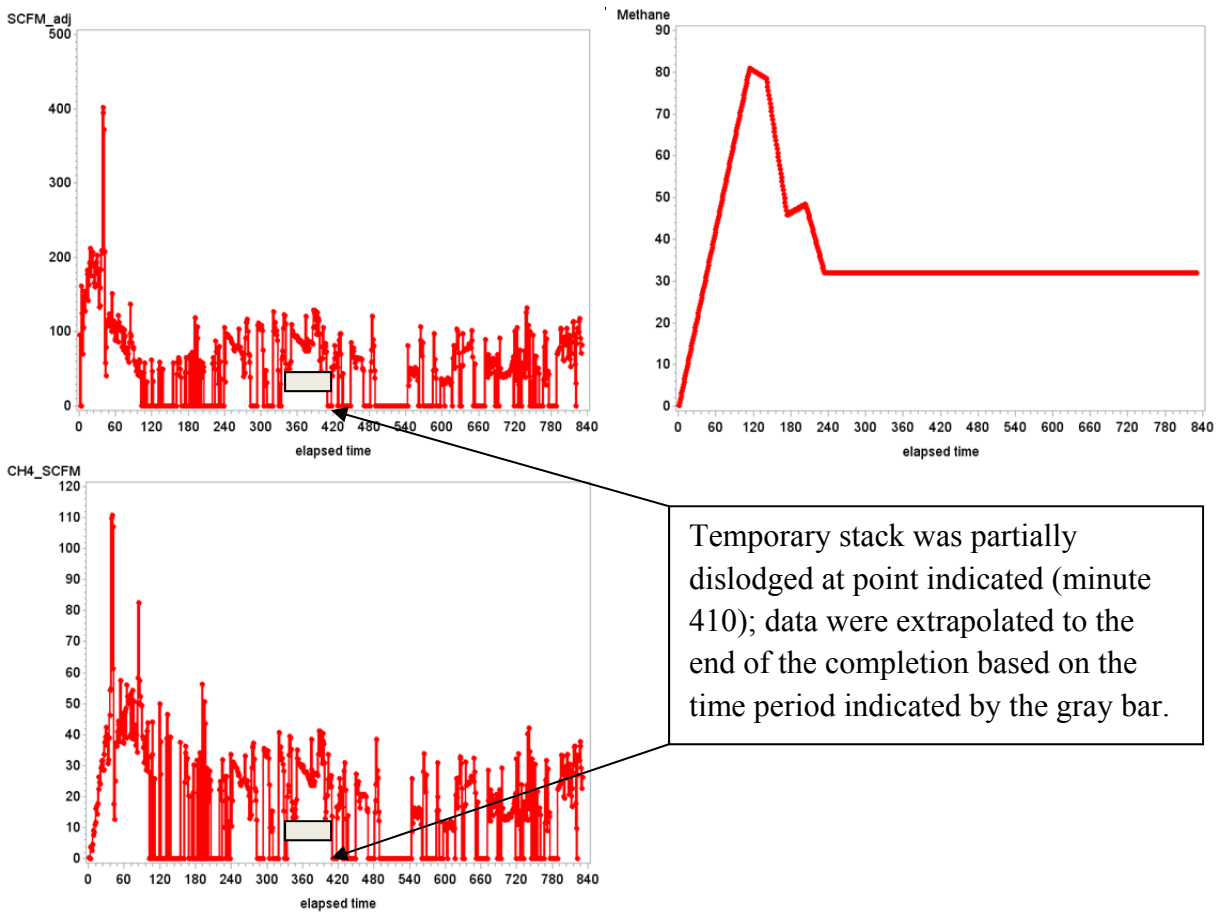
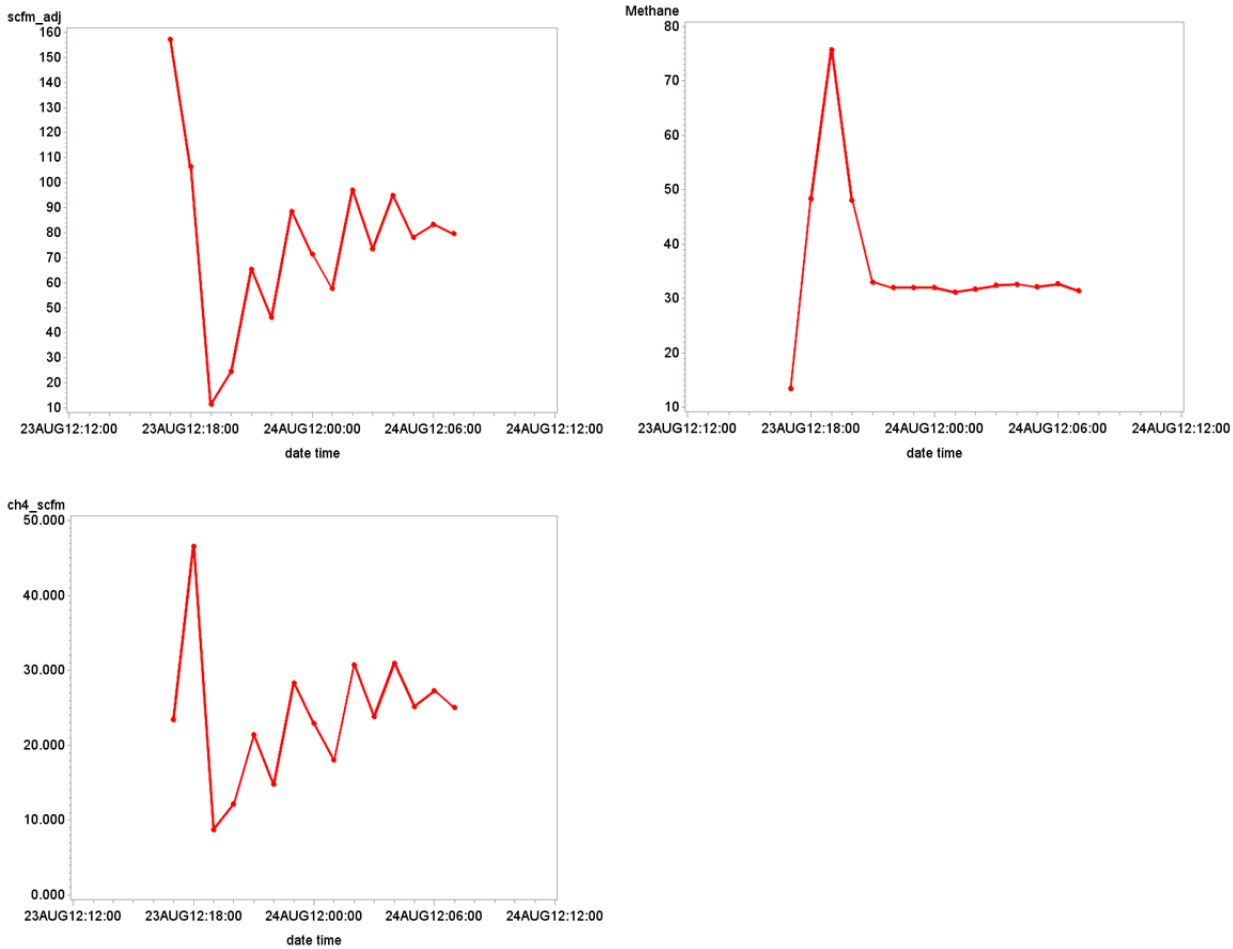


Figure GC5-1 Flowback into open-top gas buster tank, measured through temporary stack for first 409 minutes and extrapolated for the remainer of the flowback; time of day is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total methane: 21,600 ft^3 over 831 minutes (13.8 hours)



Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	21,600 ± 12,000 scf	NA
Total	21,600 scf	
Total (based on estimated average gas velocity – see Appendix C)	17,300 ± 10,000 scf	

Potential emissions:

Potential emissions = actual emissions

Gulf Coast Completion Flowback 6 Data Report

Well information
Company: GC-A

Surface Equipment Configuration
Initial flow went to an open top tank. After 24 hours, flow was then sent to a separator system. Flowback of water and gas went to a 3 phase separator operating at approximately 100 psig and 110-125°F. Gas from the separator was sent to flare. After hour 96 the well began producing oil. Oil was sent from the 3 phase separator to a ventless tank operating at 7-8 psig and 100°F and the oil was removed from the site using a vapor controlled oil transfer trucks. Gas from the ventless tank was flared. Water was discharged to a vented flowback tank. Flowback ended after 164 hours.

Flowback timeline
Hours 0-24: Flow to an open top tank

Hours 25-96: Flow to 3-phase separator, but only water produced. Gases flared.

Hours 97-164: Flow sent to 3-phase separator; gas from 3-phase separators to flare; oil from 3-phase separator sent to a ventless tank; gases from ventless tank were flared.

Hour 164: Gas to sales; flowback ended

Completion flowback total gas flows
Data from completion report
Gas from high pressure separators to flare: 13,755,000 scf
Gas composition analysis: Sample of produced gas after well was in production was 88.3 mol% methane

Total oil volume: 448 standard barrels; all to ventless tank
Total water volume: 3013 standard barrels to vented tank

Emission calculations

Emissions from open top tank

Measurements not available. Estimated as 1000 scf methane based on data from other flowbacks in region

Emissions from gas sent to flare:

A total of 13,755,000 scf of gas was sent to the flare. An upper bound on the amount of methane sent to the flare would be to assume that the gas, for the entire period, was 88.3% methane (the composition measured after the well was put into production. This percentage of methane is an upper bound for two reasons. First, the flared gases are a combination of gas from the high and low pressure separators, and the gas from the high pressure separator would be expected to have a higher methane concentration than the gas from the low pressure separator. Second, the sample was taken after the well was put into production:

13,755,000 scf * 0.883 mol fraction methane = 12,146,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

12,146,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 243,0000 scf.

Emissions vented from water flowback tank

The direct measurements of methane emissions from water flowback tanks were estimated using estimated methane solubility in water. Assuming a Henry's law constant of 4600 (MPa) (pure water, Kiepe, et al., 2003)

For a total pressure of 115 psia (0.8 MPa)

X_1= 0.8/4600 = 0.00017 mol fraction

If the gas in the separator is 88% methane, the mol fraction methane would be 0.00014. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1 g mol of methane per bbl (0.00014*8830 g mol). To one significant figure, this is 1 scf per bbl of water.

3013 bbl * 1 scf/bbl = 3,000 scf

This solubility estimate leads to an estimate of 3000 scf for the completion flowback.

Kiepe, J., Horstmann, S., Fisher, K., Gmehling, J., "Experimental Determination and Prediction of Gas Solubility Data for Methane + Water Solutions Containing Different Monovalent Electrolytes", *Industrial & Engineering Chemistry Research*, 42, 5392-5398 (2003).

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions from open top tank		1,000 scf
Emissions vented from water flowback tank		3,000 scf
Emissions from flare		243,000 scf
Total	247,000 scf	

Potential emissions:

12,146,000 scf sent to flare + 1,000 scf from open top tank + 3,000 scf from water flowback = 12,150,000 scf methane

Gulf Coast Completion Flowback 7 Data Report

Well information
Company: GC-A

Surface Equipment Configuration
Initial flow went to an open top tank. After 5 hours, flow was then sent to a separator system. Flowback of water and gas went to a 3 phase separator operating at approximately 600-1100 psig and 100-120°F. Gas from the separator was sent to flare. Oil was sent from the 3 phase separator to a ventless tank and the oil was removed from the site using a vapor controlled oil transfer trucks. Gas from the ventless tank was flared. Water was discharged to a vented flowback tank. Flowback ended after 108 hours.

Flowback timeline
Hours 0-5: Flow to an open top tank

Hours 6-108: Flow sent to 3-phase separator; gas from 3-phase separators to flare; oil from 3-phase separator sent to a ventless tank; gases from ventless tank were flared.

Hour 108: Gas to sales; flowback ended

Completion flowback total gas flows
Data from completion report
Gas from high pressure separators to flare: 5,413,000 scf
Gas composition analysis: Sample of produced gas after well was in production was 79.7 mol% methane

Total oil volume: 1543 standard barrels; all to ventless tank
Total water volume: 360 standard barrels to vented tank

Emission calculations

Emissions from open top tank

Measurements not available. Estimated as 1000 scf methane based on data from other flowbacks in region

Emissions from gas sent to flare:

A total of 5,413,000 scf of gas was sent to the flare. An upper bound on the amount of methane sent to the flare would be to assume that the gas, for the entire period, was 79.7% methane (the composition measured after the well was put into production. This percentage of methane is an upper bound for two reasons. First, the flared gases are a combination of gas from the high and low pressure separators, and the gas from the high pressure separator would be expected to have a higher methane concentration than the gas from the low pressure separator. Second, the sample was taken after the well was put into production:

5,413,000 scf * 0.797 mol fraction methane = 4,314,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

4,314,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 86,000 scf.

Emissions vented from water flowback tank

The direct measurements of methane emissions from water flowback tanks were estimated using estimated methane solubility in water. Assuming a Henry's law constant of 4600 (MPa) (pure water, Kiepe, et al., 2003)

For a total pressure of 850 psia (5.9 MPa)

X_1= 5.9/4600 = 0.0013 mol fraction

If the gas in the separator is 80% methane, the mol fraction methane would be 0.001. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 9 g mol of methane per bbl (0.001*8830 g mol). To one significant figure, this is 8 scf per bbl of water.

360 bbl * 8 scf/bbl = 3,000 scf

This solubility estimate leads to an estimate of 3000 scf for the completion flowback.

Kiepe, J., Horstmann, S., Fisher, K., Gmehling, J., "Experimental Determination and Prediction of Gas Solubility Data for Methane + Water Solutions Containing Different Monovalent Electrolytes", *Industrial & Engineering Chemistry Research*, 42, 5392-5398 (2003).

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions from open top tank		1,000 scf
Emissions vented from water flowback tank		3,000 scf
Emissions from flare		86,000 scf
Total	90,000 scf	

Potential emissions:

4,314,000 scf sent to flare + 1,000 scf from open top tank + 3,000 scf from water flowback = 4,320,000 scf methane

Midcontinent Completion 1 Data Report

Well information
Company: MC-A

Surface Equipment Configuration
Entire flowback went to a open-top flowback tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 144.7 hours.

Flowback timeline
Hours 0-145: Flow to a vented flowback tank.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack: 600,000 ft^3

Gas Samples
Vented flowback gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
0 hour 1 min	Grab	55.56
0 hour 9 min	Grab	N.D.
3 hours 12 min	Grab	67.17
14 hours 57 min	Grab	54.97
16 hours 34 min	Grab	63.76
21 hours 57 min	Grab	63.07
40 hours 30 min	Grab	49.22
41 hours 26 min	Grab	48.00
42 hours 30 min	Grab	42.97
45 hours 47 min	Grab	41.64
46 hours 40 min	Grab	9.90
61 hours 35 min	Grab	58.76
64 hours 45 min	Grab	50.16
66 hours 52 min	Grab	41.73
68 hours 59 min	Grab	51.77
88 hours 17 min	Grab	59.15
90 hours 24 min	Grab	45.53
93 hours 24 min	Grab	33.70
99 hours 09 min	Grab	27.45
100 hours 11 min	Grab	37.50
110 hours 56 min	Grab	43.90
112 hours 53 min	Grab	41.54
114 hours 31 min	Grab	39.02
116 hours 43 min	Grab	38.93

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Midcontinent Completion 1 found in the study database. The data are summarized in Figure MC1-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Midcontinent Completion 1 found in the study database.

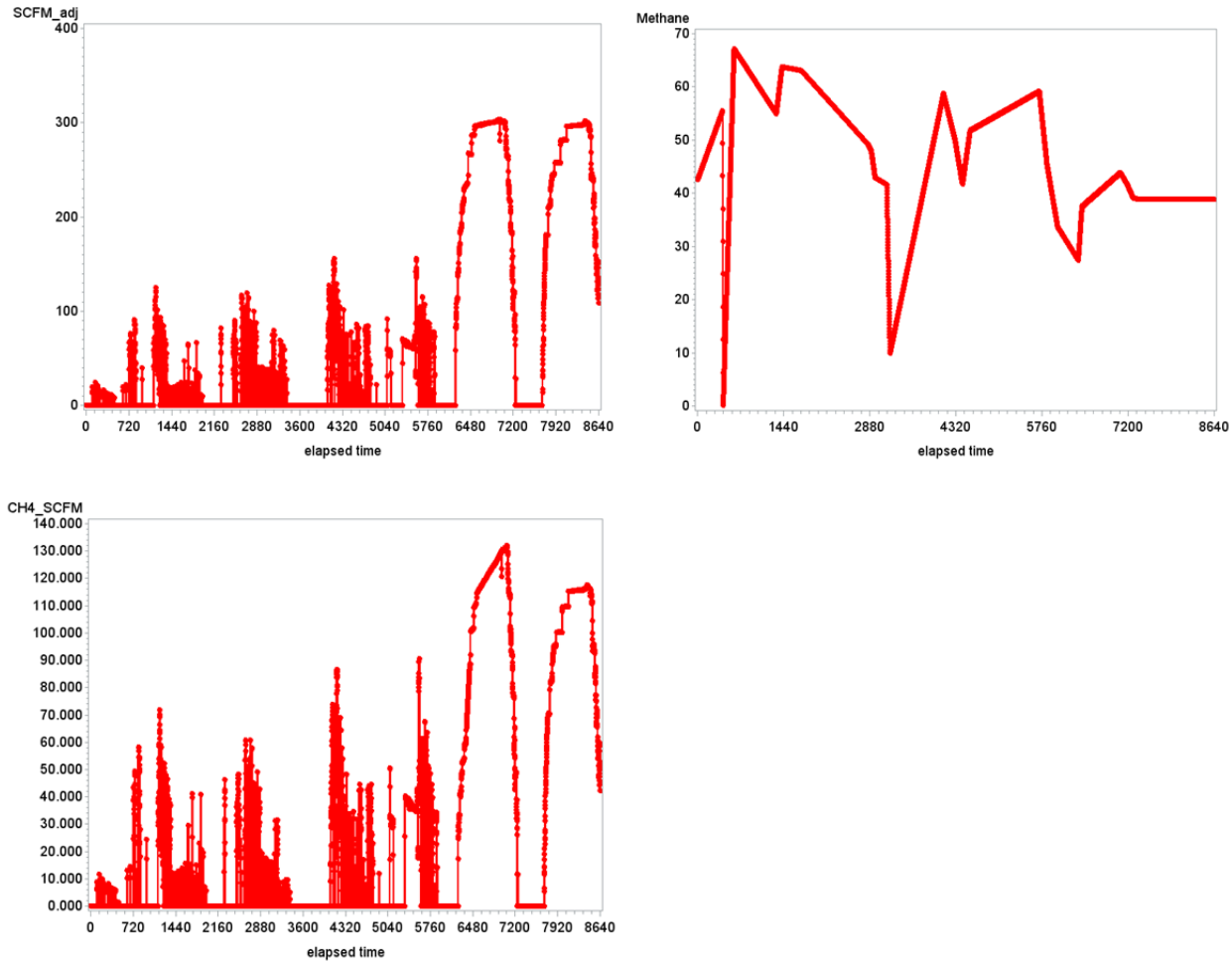
Emissions estimate = 250,000 ± 20,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 25,000
Combined uncertainty = ± 32,000

Figure MC1-1 Flowback into vented gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 600,000 ft^3 over 8683 minutes (144.7 hours)
Cumulative total methane: 248,000 ft^3 over 8683 minutes (144.7 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [233,000-264,000]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the flowback period to the open top tank, gas flow of 34,100 ft^3 and methane flow of 16,400 ± 2500 scf was measured. Emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, assume T_u=80°F (temperature not available on completion report), and a series of choke settings:

23/64 for 24 hr, 25/64 for 24 hr, 26/64 for 24 hr, 31/64 for 24 hr, 39/64 for 24 hr, 61/64 for 24 hr

$$FRv\ (ft^3/hr) = 1.27*10^5 * \pi/4*(X/64in. * 0.0254\ m/in)^2 * (187.08*300)^{0.5}$$

Flow = 720,000 ft^3 at the sonic flow conditions (300K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 4,700,000 scf. If this was assumed to be 40% methane, emissions of methane would be 1,900,000 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	250,000 ± 32,000 scf	1,900,000
Total (based on centerline gas velocity measurements)	250,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	200,000 ± 30,000scf	

Potential emissions:

Potential emissions = actual emissions

Midcontinent Completion 2 Data Report

Well information
Company: MC-A

Surface Equipment Configuration
Entire flowback went to a open-top flowback tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 147.2 hours.

Flowback timeline
Hours 0-147: Flow to a vented flowback tank.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack: 120,000 ft^3

Gas Samples
Vented flowback gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
4 hours 40 min	Grab	N.D.
10 hours 15 min	Grab	15.39
21 hours 58 min	Grab	8.03
23 hours 34 min	Grab	10.74
28 hours 57 min	Grab	7.20
47 hours 24 min	Grab	12.73
48 hours 2 min	Grab	12.99
49 hours 30 min	Grab	11.40
52 hours 48 min	Grab	23.35
53 hours 40 min	Grab	44.97
68 hours 35 min	Grab	61.05
71 hours 45 min	Grab	39.78
73 hours 52 min	Grab	40.64
76 hours 00 min	Grab	35.52
95 hours 17 min	Grab	40.06
97 hours 24 min	Grab	32.76
100 hours 24 min	Grab	32.58
105 hours 50 min	Grab	27.59
106 hours 03 min	Grab	27.67
117 hours 56 min	Grab	29.74
119 hours 53 min	Grab	34.95
121 hours 31 min	Grab	37.38
123 hours 43 min	Grab	35.12

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Midcontinent Completion 2 found in the study database. The data are summarized in Figure MC2-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Midcontinent Completion 2 found in the study database.

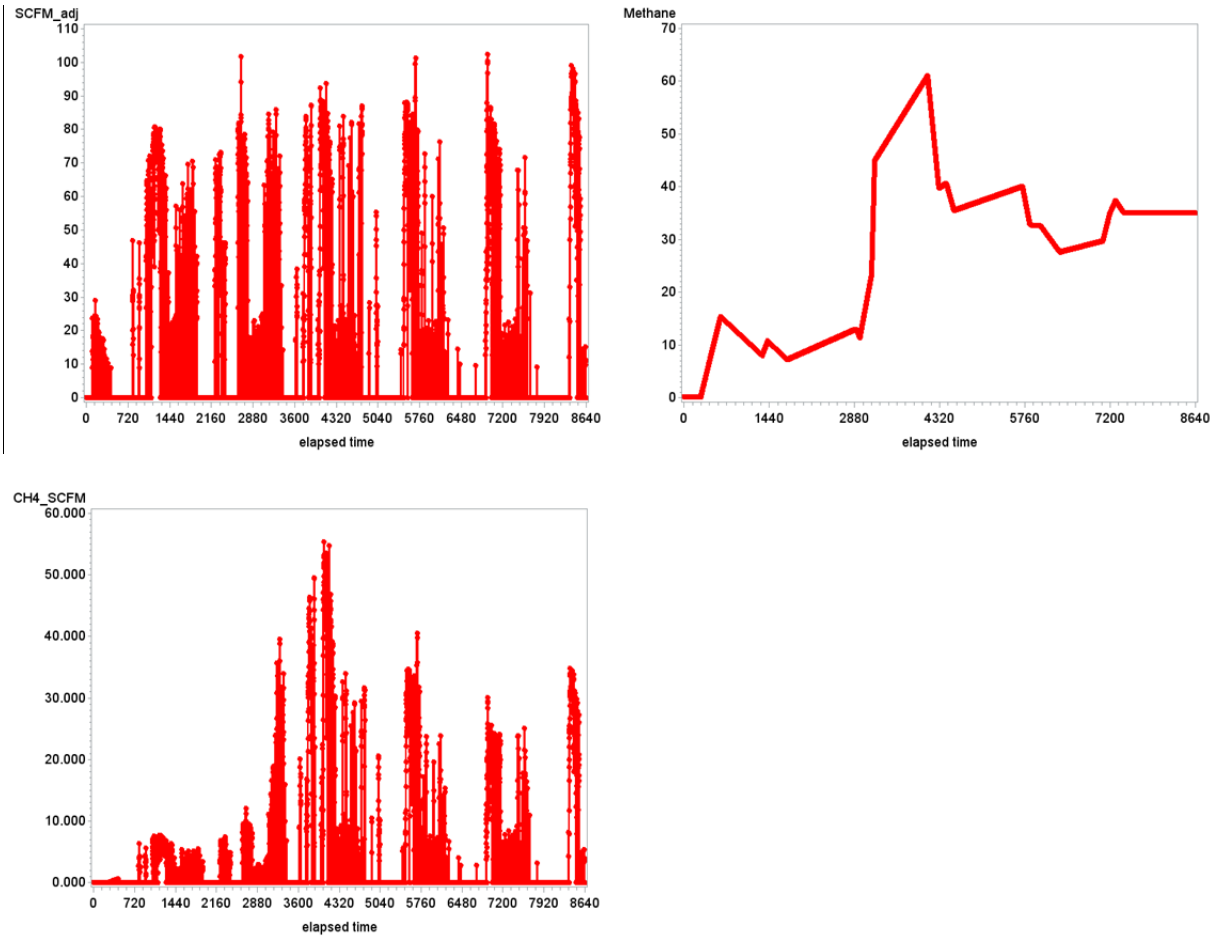
Emissions estimate = 34,000 ± 4,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 3,400
Combined uncertainty = ± 5,000

Figure MC2-1 Flowback into vented gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 120,000 ft^3 over 8830 minutes (147.2 hours)
Cumulative total methane: 34,400 ft^3 over 8830 minutes (147.2 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [29,700-37,900]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the flowback period to the open top tank, gas flow of 34,100 ft^3 and methane flow of 16,400 ± 2500 scf was measured. Emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, assume T_u=80°F (temperature not available on completion report), and a series of choke settings:

29/64 for 24 hr, 31/64 for 24 hr, 33/64 for 24 hr, 39/64 for 24 hr, 47/64 for 24 hr, 64/64 for 24 hr

$$FRv\ (ft^3/hr) = 1.27*10^5 * \pi/4*(X/64in. * 0.0254\ m/in)^2 * (187.08*300)^{0.5}$$

Flow = 960,000 ft^3 at the sonic flow conditions (300K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 6,300,000 scf. If this was assumed to be 40% methane, emissions of methane would be 2,500,000 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	34,000 ± 5,000 scf	2,500,000
Total (based on centerline gas velocity measurements)	34,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	27,000 ± 4,000scf	

Potential emissions:

Potential emissions = actual emissions

Midcontinent Completion 3 Data Report

Well information
Company: MC-B

Surface Equipment Configuration
Nearly entire flowback went from the well, through a separator, to a vented flowback tank. The separator was operated at a pressure of 96 psig and a temperature of 70°F. Gas from the separator was sent to sales. The liquid from the separator was sent to a vented flowback tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. A small fraction of the completion flowback was sent through a different separator. Gas from this separator was also sent to sales. Liquid from this separator was sent to a sand trap.

Flowback timeline
Hours 0-138: Flowback to a separator; gas from the separator to sales; liquid from the separator to a vented flowback tank.

Sampling was conducted for approximately the first 40% of the completion; at that point, hurricane conditions required the removal of the temporary stack; the completion continued for another 2.5 days and the data from the first 40% of the completion was used to estimate the emissions for the remainer of the flowback.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack: 4,821 ft^3 during initial phase of completion

Estimated total flow
Total gas flow 38,800 ft^3 over entire completion

Gas Samples

Vented flowback tank gas samples

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
20 hours 44 min	Grab	N.D.
21 hours 45 min	Grab	N.D.
22 hours 45 min	Grab	N.D.
23 hours 35 min	Grab	N.D.
24 hours 32 min	Grab	N.D.
25 hours 34 min	Grab	1.64
26 hours 16 min	Grab	2.06
40 hours 19 min	Grab	8.89
41 hours 40 min	Grab	9.75
42 hours 33 min	Grab	9.74

Emission calculations

Emissions measured through temporary stack during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Midcontinent Completion 3 found in the study database. The data are summarized in Figure MC3-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Midcontinent Completion 3 found in the study database.

Emissions estimate = 150 ± 50 scf

Estimated emissions over entire completion

Total gas flow rate and gas composition measurements from the last three hours of measurements were relatively stable and were used to extrapolate data for the remainer of the flowback. Total gas flow rates were averaged and standard deviations were determined for one hour periods. Gas compositions over the final three hours of sampling, were averaged with standard deviations determined. Random draws for flow rate and gas composition, based on the statistics of the data from the final three hours of sampling, were used for the remaining period of sampling. The extrapolated data are shown in Figure MC3-2. Based on this approach, the total emissions were estimated as 3,400 scf methane with an uncertainty bound of 33% of the estimated flow, based on the uncertainties in the emission estimate during the initial flow.

Estimated total emissions = 3,400 scf ± 1,100 scf.

Figure MC3-1 Flowback into vented tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 4,800 ft^3 over initial phase
Cumulative total methane: 150 ft^3 over initial phase

Two other estimates based on using the upper and lower ends of possible methane percentage: [104-184]

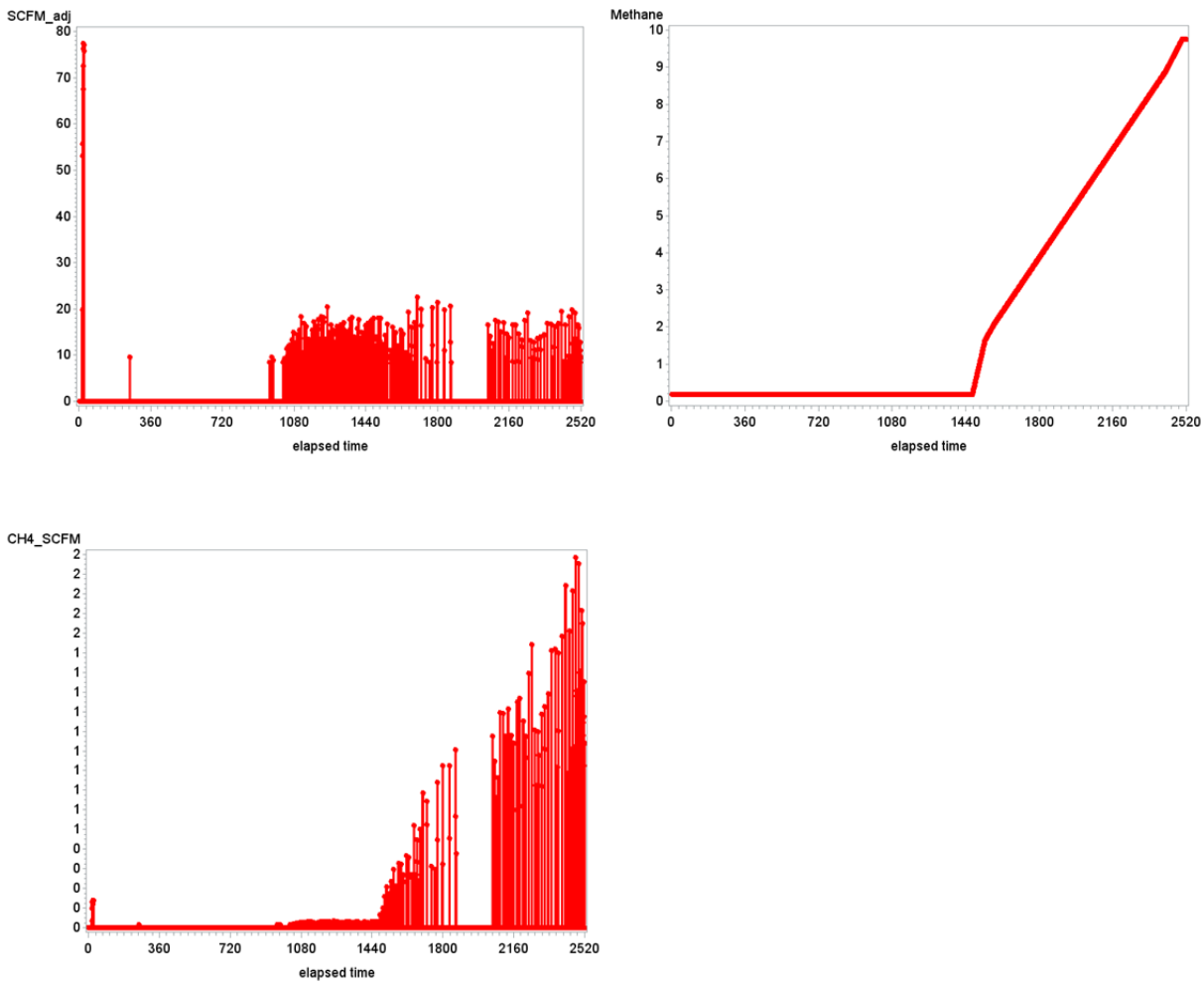
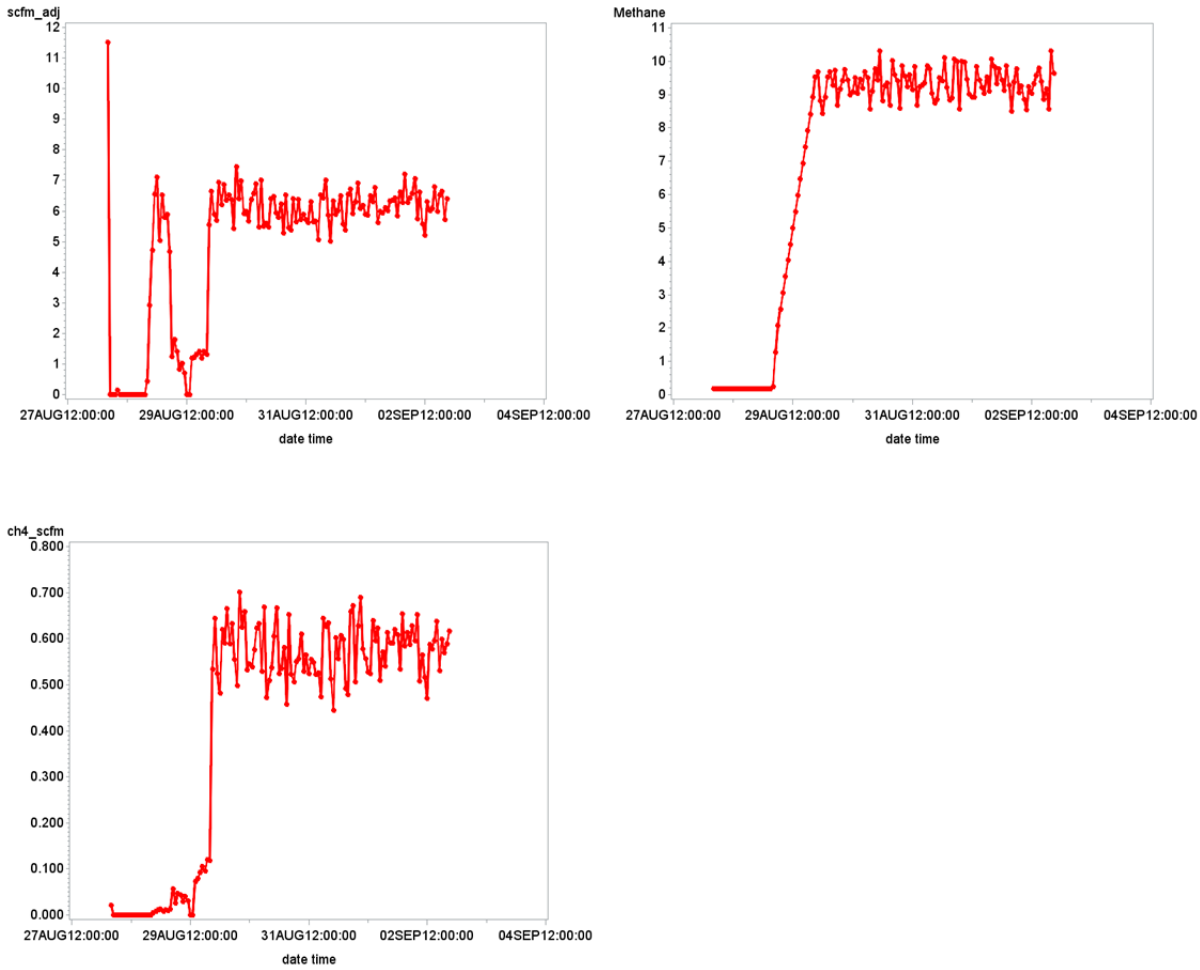


Figure MC3-2 Flowback into open-top gas buster tank, measured through temporary stack for initial phase and extrapolated for the remainer of the flowback; time of day is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.



Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	3,400 scf	NA
Total (based on centerline gas velocity measurements)	3,400 scf	
Total (based on estimated average gas velocity – see Appendix C)	2,700 scf	

Potential emissions:

20,500,000 scf sent to sales + 2,700 scf from vented tank = 20,500,000 scf methane

Midcontinent Completion 4 Data Report

Well information
Company: MC-B

Surface Equipment Configuration
Nearly entire flowback went from the well, through a separator, to a vented flowback tank. The separator was operated at a pressure of 98 psig and a temperature of 70°F. Gas from the separator was sent to sales. The liquid from the separator was sent to a vented flowback tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. A small fraction of the completion flowback was sent through a different separator. Gas from this separator was also sent to sales. Liquid from this separator was sent to a sand trap.

Flowback timeline
Hours 0-138: Flowback to a separator; gas from the separator to sales; liquid from the separator to a vented flowback tank.

Sampling was conducted for approximately the first 40% of the completion; at that point, hurricane conditions required the removal of the temporary stack; the completion continued for another 2.5 days and the data from the first 40% of the completion was used to estimate the emissions for the remainer of the flowback.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack: 10,732 ft^3 during initial phase of completion

Estimated total flow
Total gas flow 34,000 ft^3 over entire completion

Gas Samples

Vented flowback gas samples

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
21 hours 52 min	Grab	1.22
22 hours 48 min	Grab	2.67
23 hours 39 min	Grab	7.15
24 hours 34 min	Grab	11.23
25 hours 36 min	Grab	9.50
26 hours 17 min	Grab	11.30
40 hours 36 min	Grab	9.48
41 hours 43 min	Grab	8.97
42 hours 36 min	Grab	10.55

Emission calculations

Emissions measured through temporary stack during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Midcontinent Completion 4 found in the study database. The data are summarized in Figure MC4-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Midcontinent Completion 4 found in the study database.

Emissions estimate = 540 ± 120 scf

Estimated emissions over entire completion

Total gas flow rate and gas composition measurements from the last three hours of measurements were relatively stable and were used to extrapolate data for the remainer of the flowback. Total gas flow rates were averaged and standard deviations were determined for one hour periods. Gas compositions over the final three hours of sampling, were averaged with standard deviations determined. Random draws for flow rate and gas composition, based on the statistics of the data from the final three hours of sampling, were used for the remaining period of sampling. The extrapolated data are shown in Figure MC4-2. Based on this approach, the total emissions were estimated as 3,000 scf methane with an uncertainty bound of 20% of the estimated flow, based on the uncertainties in the emission estimate during the initial flow.

Estimated total emissions = 3,000 ± 600 scf.

Figure MC4-1 Flowback into vented tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 10,732 ft^3 (over initial phase)
Cumulative total methane: 540 ft^3 (over initial phase)

Two other estimates based on using the upper and lower ends of possible methane percentage: [477-656]

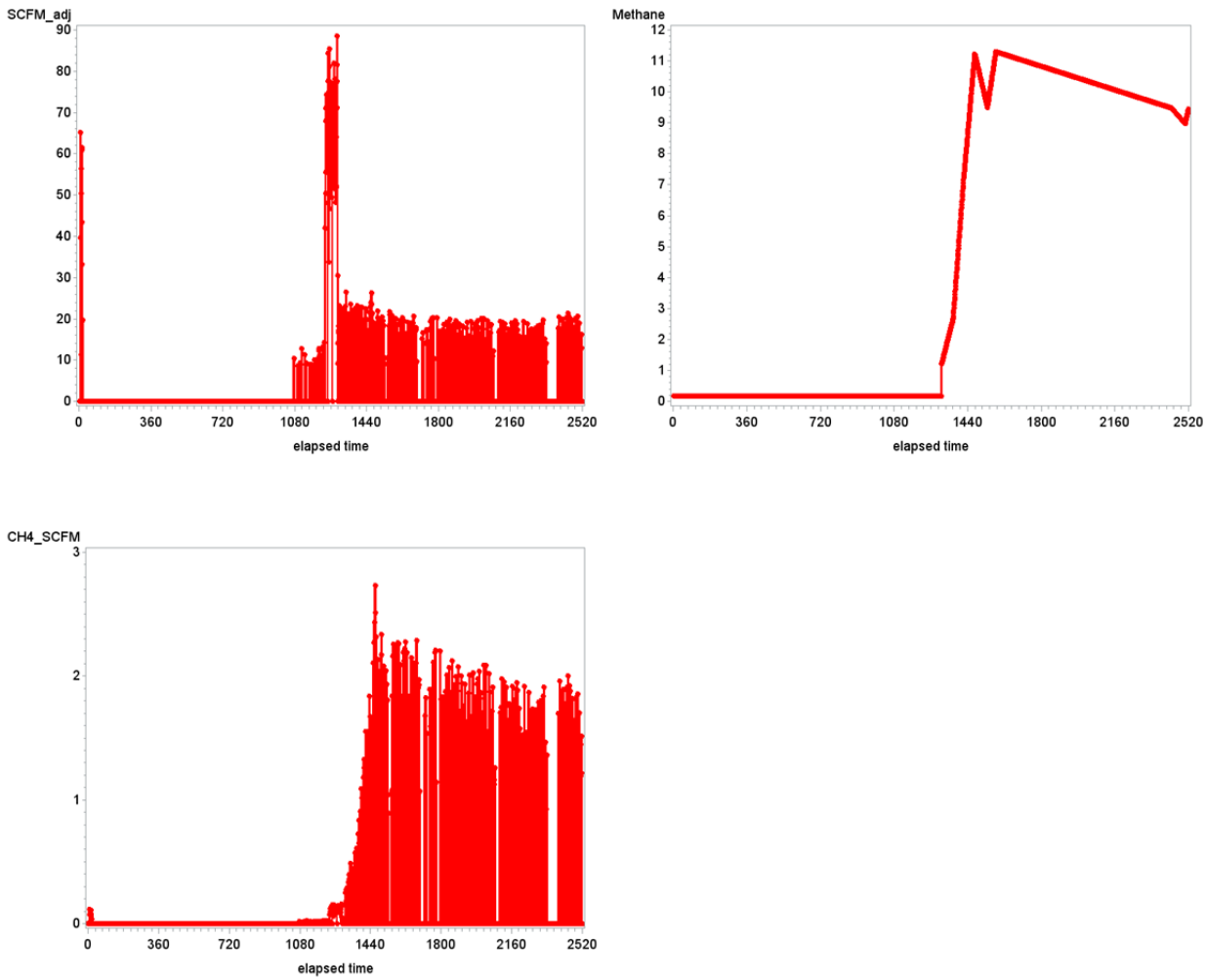
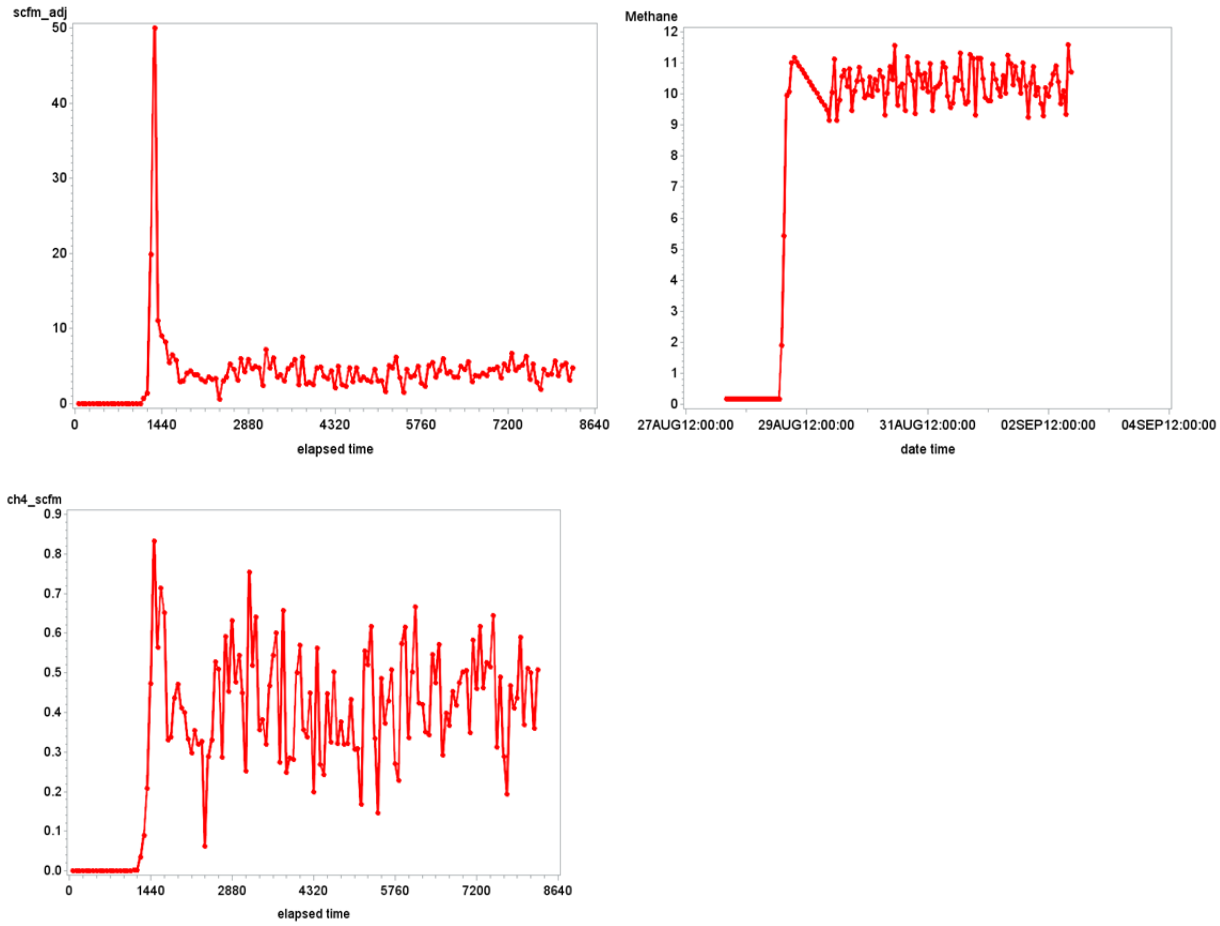


Figure MC4-2 Flowback into open-top gas buster tank, measured through temporary stack for first phase and extrapolated for the remainer of the flowback; time of day is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.



Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	3,000 scf	NA
Total (based on centerline gas velocity measurements)	3,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	2,400 scf	

Potential emissions:

17,500,000 scf sent to sales + 2,400 scf from vented tank = 17,500,000 scf methane

Midcontinent Completion 5 Data Report

Well information
Company: MC-B

Nearly entire flowback went from the well, through a separator, to a vented flowback tank. The separator was operated at a pressure of 94 psig and a temperature of 59°F. Gas from the separator was sent to sales. The liquid from the separator was sent to a vented flowback tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. A small fraction of the completion flowback was sent through a different separator. Gas from this separator was also sent to sales. Liquid from this separator was sent to a sand trap.

Flowback timeline
Hours 0-138: Flowback to a separator; gas from the separator to sales; liquid from the separator to a vented flowback tank.

Sampling was conducted for approximately the first 40% of the completion; at that point, hurricane conditions required the removal of the temporary stack; the completion continued for another 2.5 days and the data from the first 40% of the completion was used to estimate the emissions for the remainer of the flowback.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack: 4,009 ft^3 during initial phase of completion

Estimated total flow
Total gas flow 28,800 ft^3 over entire completion

Gas Samples

Vented flowback gas samples

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
24 hours 37 min	Grab	N.D.
25 hours 38 min	Grab	N.D.
26 hours 20 min	Grab	1.82
40 hours 39 min	Grab	7.80
41 hours 45 min	Grab	9.45
42 hours 40 min	Grab	10.05

Emission calculations

Emissions measured through temporary stack during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Midcontinent Completion 5 found in the study database. The data are summarized in Figure MC5-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Midcontinent Completion 5 found in the study database.

$$\text{Emissions estimate} = 170 \pm 80 \text{ scf}$$

Estimated emissions over entire completion

Total gas flow rate and gas composition measurements from the last three hours of measurements were relatively stable and were used to extrapolate data for the remainer of the flowback. Total gas flow rates were averaged and standard deviations were determined for one hour periods. Gas compositions over the final three hours of sampling, were averaged with standard deviations determined. Random draws for flow rate and gas composition, based on the statistics of the data from the final three hours of sampling, were used for the remaining period of sampling. The extrapolated data are shown in Figure MC5-2. Based on this approach, the total emissions were estimated as 2,600 scf methane with an uncertainty bound of 40% of the estimated flow, based on the uncertainties in the emission estimate during the initial flow.

$$\text{Estimated total emissions} = 2{,}600 \pm 1{,}100 \text{ scf.}$$

Figure MC5-1 Flowback into vented tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 4,009 ft^3 over initial phase
Cumulative total methane: 170 ft^3 over initial phase

Two other estimates based on using the upper and lower ends of possible methane percentage: [103-251]

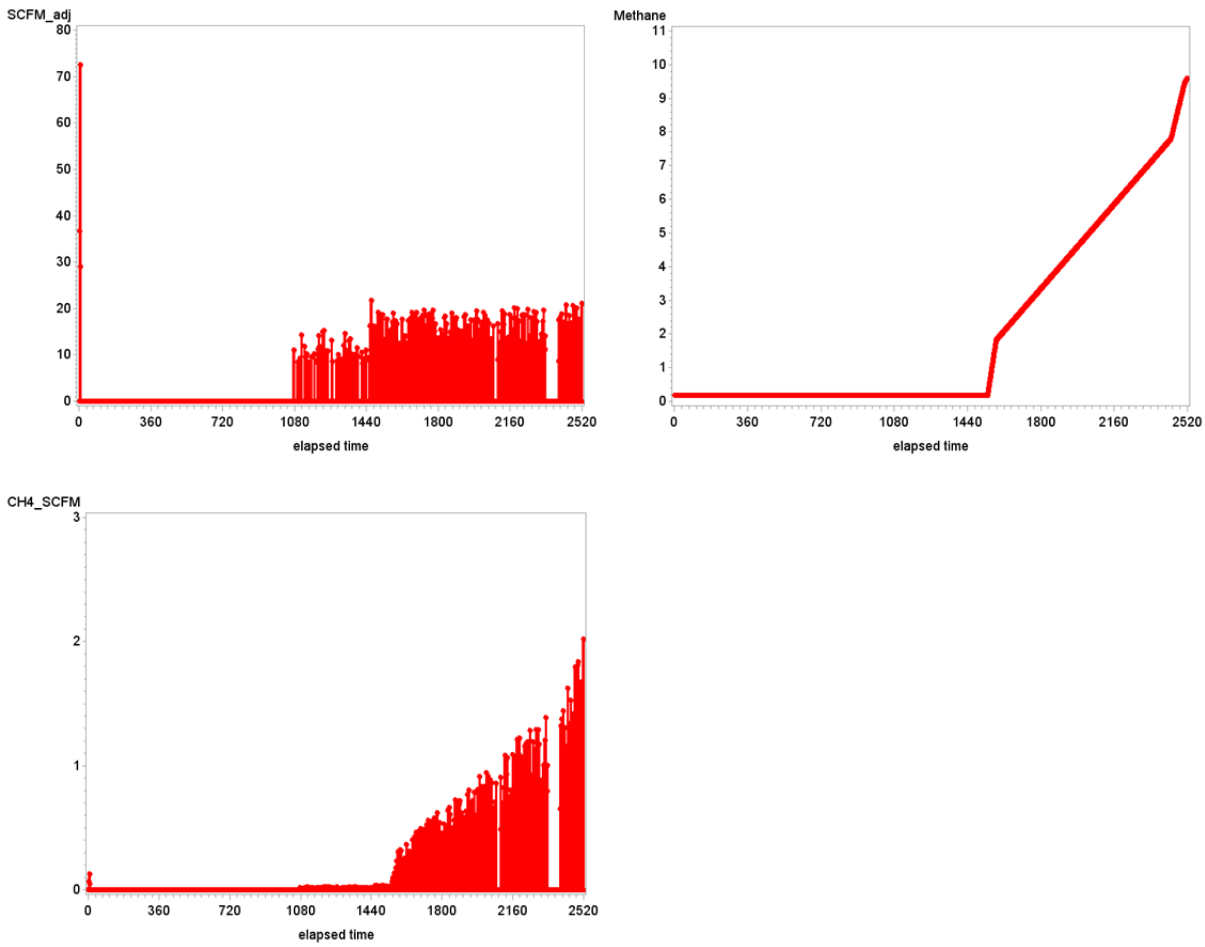
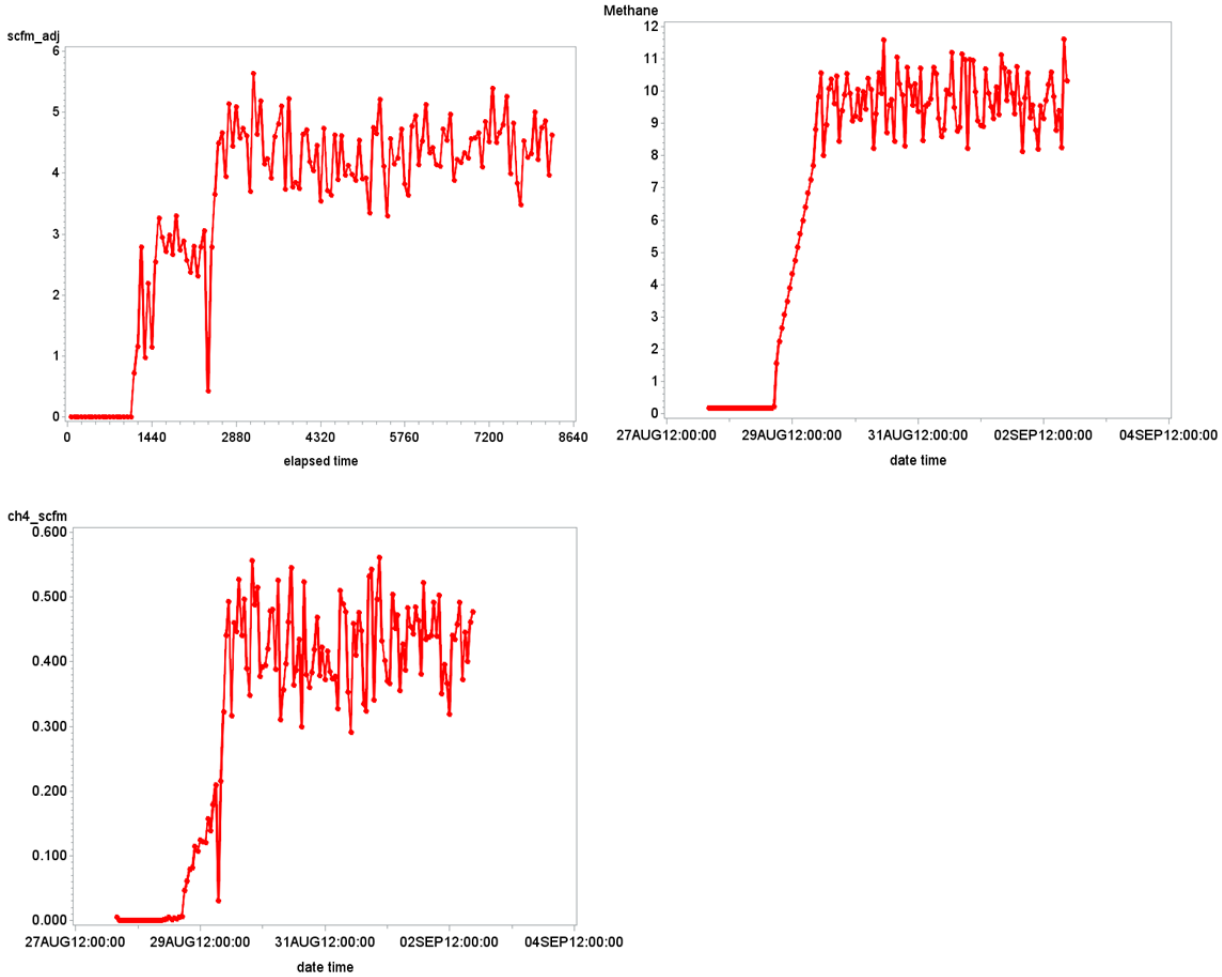


Figure MC5-2 Flowback into open-top gas buster tank, measured through temporary stack for first phase and extrapolated for the remainer of the flowback; time of day is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.



Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	2,600 scf	NA
Total (based on centerline gas velocity measurements)	2,600 scf	
Total (based on estimated average gas velocity – see Appendix C)	2,100 scf	

Potential emissions:

18,700,000 scf sent to sales + 2,100 scf from vented tank = 18,700,000 scf methane

Rocky Mountain Completion 1 Data Report

Well information
Company: RM-A

Surface Equipment Configuration
Entire flowback went to an open-top tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 30.2 hours.

Flowback timeline
Hours 0-30: Flow to gas-buster in open top tank; an initial flow of gas was followed by an extended period with no gas flow. During this period, site personnel accessed the gas buster and when gas flow resumed, some leaks in the open tank seal were noted.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 45,000 ft^3

Gas Samples

Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
1 hr 42 min	Grab	49.90%
2 hr 28 min	Grab	54.17%
29 hr 23 min	Grab	31.05%

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 1 found in the study database. The data are summarized in Figure RM1-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 1 found in the study database.

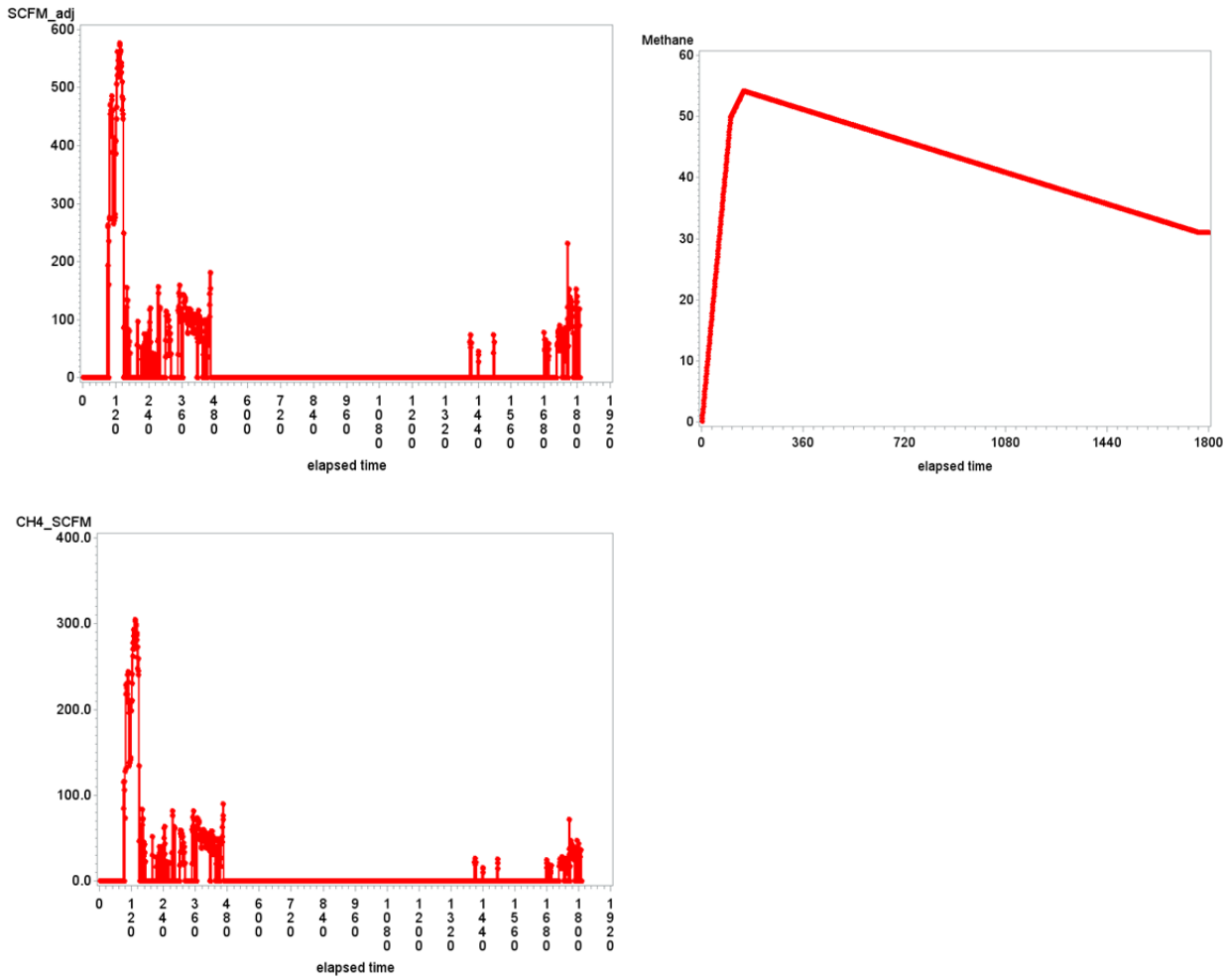
Emissions estimate = 21,800 ± 5000 scf

This may be biased low due to a leak in the cover of the open top tank, which was caused when site personnel needed to access the gasbuster. This leak allowed some gas to escape during the period from roughly hour 2 up to 14:10 on 11/2, when the well was temporarily shut, leading to the zero flow shown in Figure RM1-1. Note that the zero flow is not due to a leak in the open tank cover, instead, the leak in the open tank cover may explain some of the reduced flow after the large spike in the flow between hours 1 and 2. Based on this leak, the study team estimates that the emissions for this completion is:

Emissions estimate = 30,000 ± 10,000 scf

Figure RM1-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 45,000 ft^3 over 1811 minutes (30.2 hours)
Cumulative total methane: 21,800 ft^3 over 1811 minutes (30.2 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [16,630 – 23,682]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:

During the flowback period to the open top tank, gas flow of 45,000 ft^3 and methane flow of 30,000 ± 10,000 scf was measured. Emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=52°F (an average value during the flowback):

$$FRv\ (ft^3/hr) = 1.27*10^5 * \pi/4*(128/64in. * 0.0254\ m/in)^2 * (187.08*284)^{0.5}$$

Flow = 60,000 ft^3/hr at the sonic flow conditions (284K, however, no pressure was recorded due to an iced pressure gauge, assume 1 atm)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 60,000 scf/h. If this was assumed to be 50% methane, emissions of methane would be 50,000 scf/h for roughly 6 hr (300,000 scf).

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	30,000 ± 10,000 scf	300,000
Total (based on centerline gas velocity measurements)	30,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	24,000 ± 8,000scf	

Potential emissions:

Potential emissions = actual emissions

Rocky Mountain Completion 2 Data Report

Well information
Company: RM-A

Surface Equipment Configuration
Entire flowback went to an open-top tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 30.1 hours.

Flowback timeline
Hours 0-30: Flow to gas-buster in open top tank; an extended period with little to no gas flow was followed by gas flow in the final 6 hours of the flowback.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 34,000 ft^3

Gas Samples

Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
24 hr 50 min	Grab	47.01%
27 hr 13 min	Grab	60.17%
28 hr 08 min	Grab	48.44%
29 hr 06 min	Grab	39.04%

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. It was assumed that gas at the start of the completion contained no methane. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 2 found in the study database. The data are summarized in Figure RM2-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 2 found in the study database.

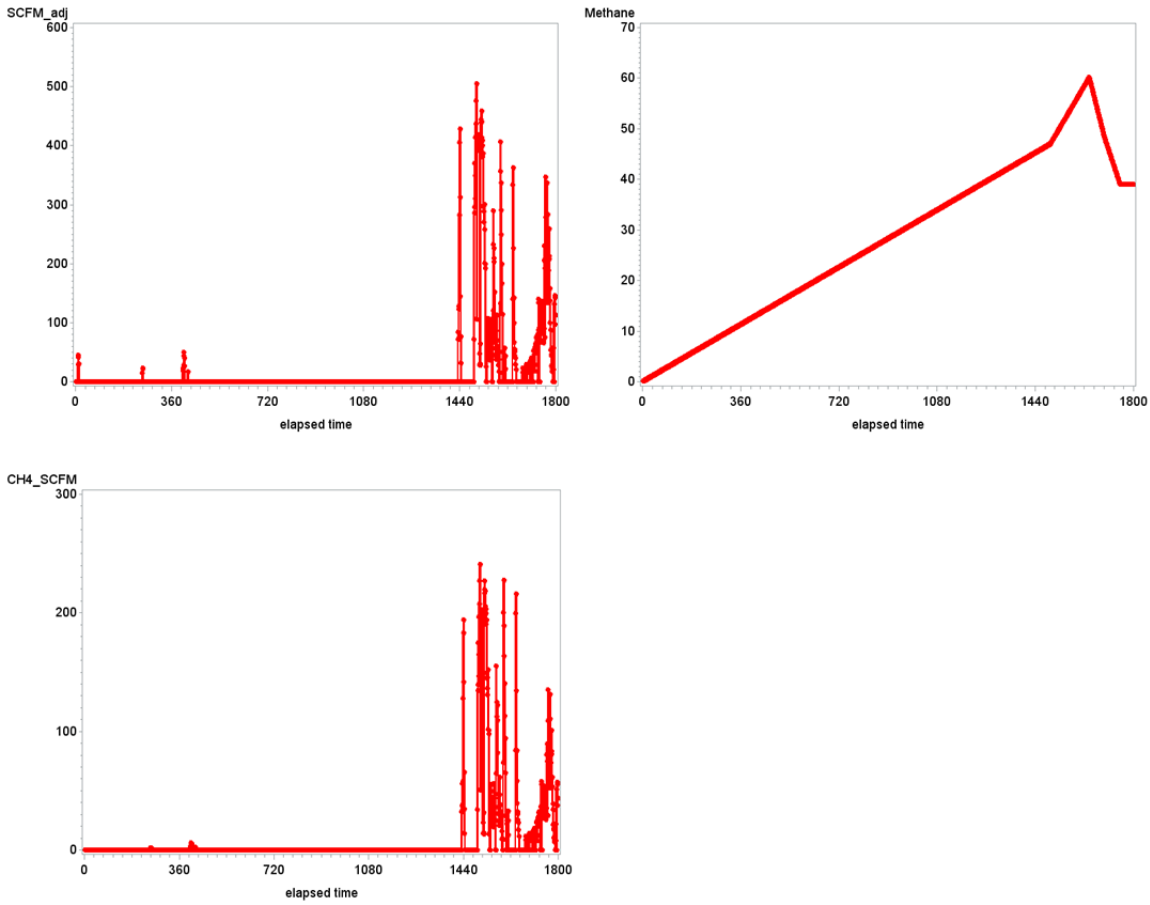
Emissions estimate = 16,000 ± 2500 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 1,600
Combined uncertainty = ± 3,000

Figure RM2-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 34,000 ft^3 over 1807 minutes (30.1 hours)
Cumulative total methane: 16,000 ft^3 over 1807 minutes (30.1 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [13,900 – 18,400]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the flowback period to the open top tank, gas flow of 34,100 ft^3 and methane flow of 16,400 ± 2500 scf was measuredEmissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, assume T_u=80°F (temperature not available on completion report), and an average choke setting of 40/64 (this varied during the completion but was roughly 40/64 when most of the gas flow occurred; the period of gas flow was 6 hr at the end of the completion):

$$FRv\ (ft^3/hr) = 1.27*10^5* \pi/4*(40/64in. * 0.0254\ m/in)^2* (187.08*300)^{0.5}$$

Flow = 5,900 ft^3/hr at the sonic flow conditions (300K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 41,500 scf/h. If this was assumed to be 50% methane, emissions of methane would be 20,700 scf/h.

For 6 hours of flow, this would be 120,000 scf methane.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	16,000 ± 3,000 scf	120,000
Total (based on centerline gas velocity measurements)	16,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	13,000 ± 2,000scf	

Potential emissions:

Potential emissions = actual emissions

Rocky Mountain Completion 3 Data Report

Well information
Company: RM-B

Surface Equipment Configuration
Flowback went to a gas-buster tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 44.5 hours.

Flowback timeline
Hours 0-44: Flow to gas-buster in open top tank;

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 43,800 scf

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
34 hours 41	Grab	41.37
35 hours 59	Grab	17.23
36 hours 39	Grab	18.67
38 hours 23	Grab	12.61
40 hours 28	Grab	47.87

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 3 found in the study database. The data are summarized in Figure RM3-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 3 found in the study database.

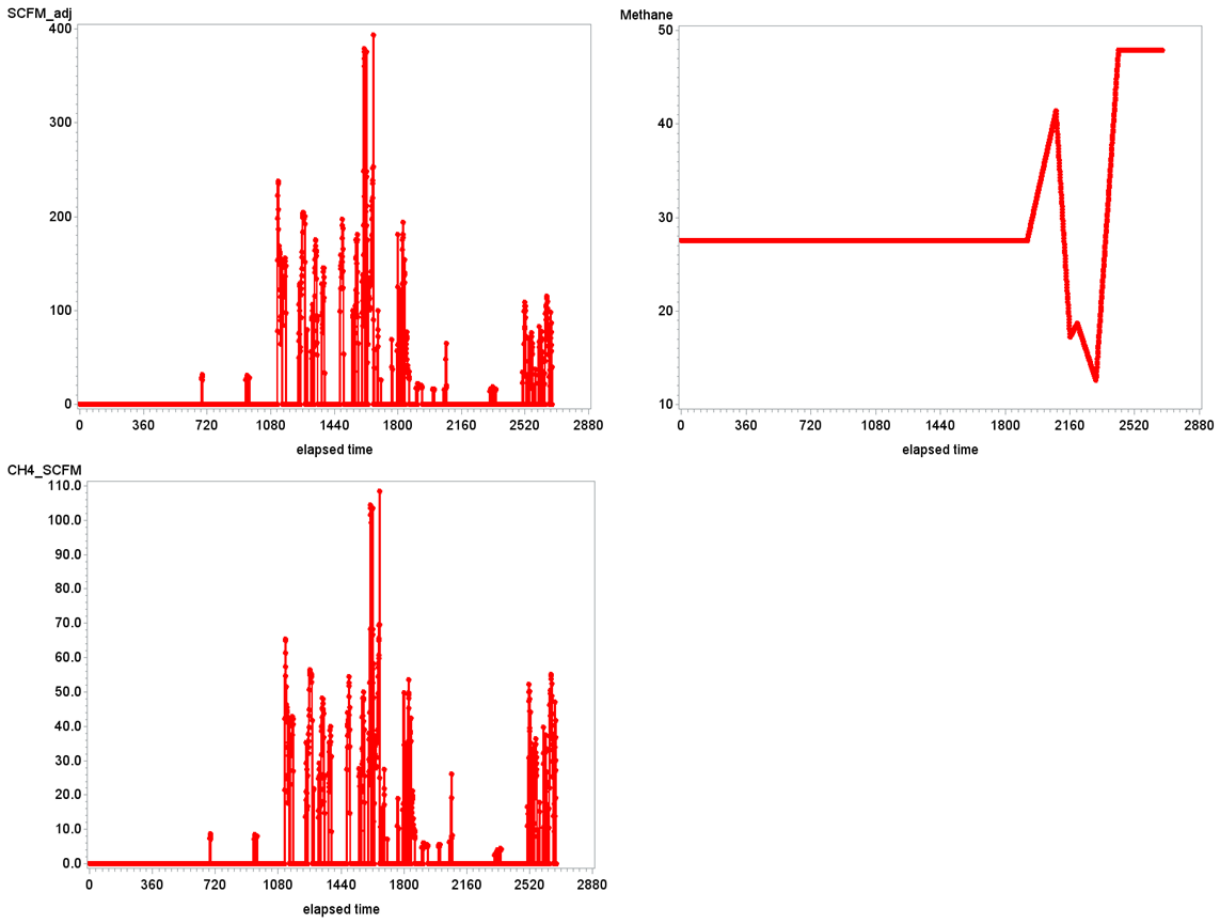
Emissions estimate = 13,000 ± 7,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 1,300
Combined uncertainty = ± 7,000

Figure RM3-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 43,800 ft^3 over 2,673 minutes (44.5 hours)
Cumulative total methane: 13,000 ft^3 over 2,673 minutes (44.5 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [6,950-19,900]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the initial flowback period to the open top tank, gas flow of 43,800 scf and methane flow of 13,000 ± 7,000 scf was measured. Since at all times during these initial 44 hours, the well pressure was more than double the pressure downstream of the choke, in the absence of direct measurements, emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A\ *\ (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=100°F (assumed value), and a choke settings of 15/64" for 1 hr, 18/64" for 1 hour. 21/64" for 4 hr, 23/64" for 3 hr, 25/64" for 18 hr, 26/64" for 8 hr:

Flow = 80,000 scf at the sonic flow conditions (311K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 500,000 scf. If this was assumed to be 25% methane (approximately the average of an assumed initial value of 0% and a final value of approximately 50%), emissions of methane would be 250,000 scf/h.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	13,000 ± 7,000 scf	250,000 scf
Total (based on centerline gas velocity measurements)	13,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	10,400 ± 6,000scf	

Potential emissions:

Potential emissions = actual emissions

Rocky Mountain Completion 4 Data Report

Well information
Company: RM-B

Surface Equipment Configuration
Flowback went to a gas-buster tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 34.3 hours.

Flowback timeline
Hours 0-34: Flow to gas-buster in open top tank;

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 90,100 scf

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
3 34 min	Grab	20.00
4 22 min	Grab	1.16
6 16 min	Grab	N.D.
7 12 min	Grab	4.32
8 00 min	Grab	33.63
9 28 min	Grab	34.65
27 44 min	Grab	47.81
28 37 min	Grab	21.22
29 47 min	Grab	55.28
30 37 min	Grab	35.52
32 31 min	Grab	26.17
33 52 min	Grab	39.39

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 4 found in the study database. The data are summarized in Figure RM4-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 4 found in the study database.

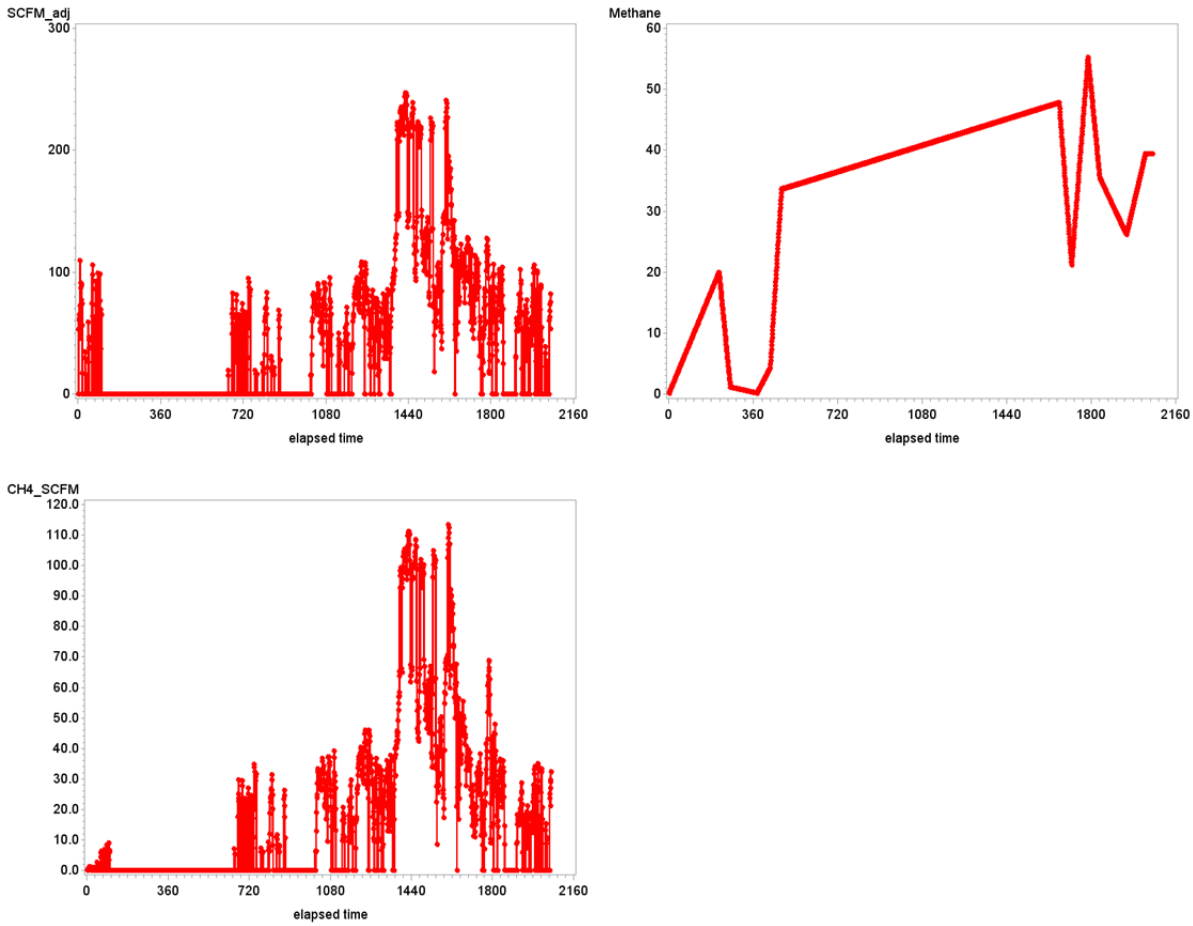
Emissions estimate = 37,000 ± 9,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 3,700
Combined uncertainty = ± 10,000

Figure RM4-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 90,100 ft^3 over 2,061 minutes (34.3 hours)
Cumulative total methane: 37,000 ft^3 over 2,061 minutes (34.3 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [27,600-42,600]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the initial flowback period to the open top tank, gas flow of 90,100 scf and methane flow of 39,000 ± 9,000 scf was measured. Since at all times during these 34 hours, the well pressure was more than double the pressure downstream of the choke, in the absence of direct measurements, emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A\ *\ (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=100°F (assumed value), and a choke settings of 14/64" for 1 hr, 17/64" for 4 hr, 18/64" for 6 hr, 19/64" for 8 hr, 21/64" for 4 hr, 23/64" for 7 hr, 25/64" for 3 hr, 26/64" for 1 hr:

Flow = 53,800 scf at the sonic flow conditions (311K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 340,000 scf. If this was assumed to be 25% methane (approximately the average of an assumed initial value of 0% and a final value of approximately 50%), emissions of methane would be 85,000 scf/h.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	37,000 ±10,000 scf	85,000 scf
Total (based on centerline gas velocity measurements)	37,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	30,000 ± 8,000 scf	

Potential emissions:

Potential emissions = actual emissions

Rocky Mountain Completion 5 Data Report

Well information
Company: RM-B

Surface Equipment Configuration
Flowback went to a gas-buster tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 68.4 hours.

Flowback timeline
Hours 0-64: Flow to gas-buster in open top tank;

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 175,000 scf

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
14 12 min	Grab	28.21
14 51 min	Grab	48.97
19 05 min	Grab	32.40
20 11 min	Grab	8.33
38 28 min	Grab	60.93
42 48 min	Grab	53.60
44 49 min	Grab	10.97
45 35 min	Grab	4.95
60 33 min	Grab	4.99
61 27 min	Grab	0.36
62 16 min	Grab	N.D.
63 15 min	Grab	N.D.

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion5 found in the study database. The data are summarized in Figure RM5-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 5 found in the study database.

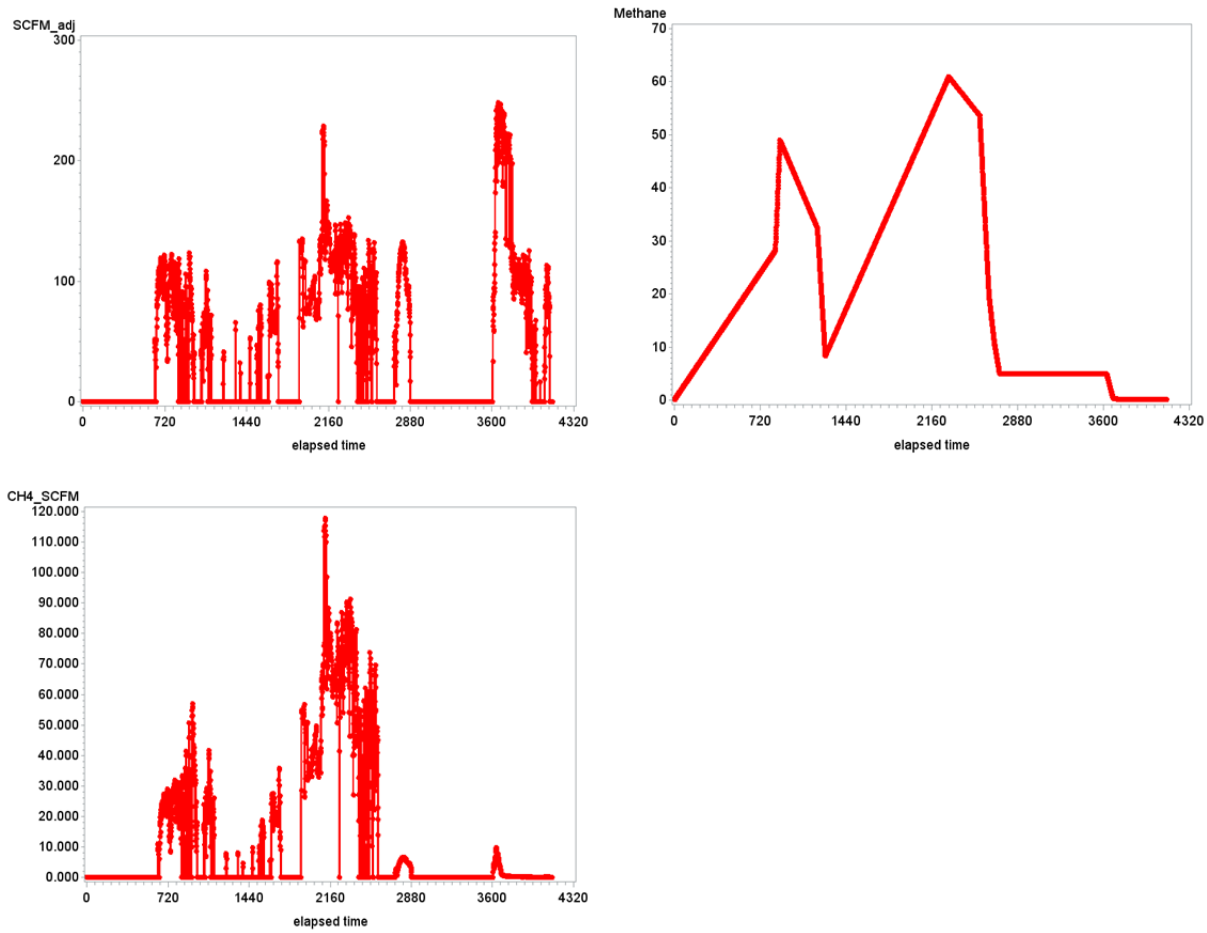
Emissions estimate = 49,000 ± 30,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 4,900
Combined uncertainty = ± 30,000

Figure RM5-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 175,000 ft^3 over 4,107 minutes (68.4 hours)
Cumulative total methane: 49,000 ft^3 over 4,107 minutes (68.4 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [19,600-60,000]



Comparisons of measured emissions to emissions estimated using conventional reporting methods

Emissions during flow to open top tank:
During the initial flowback period to the open top tank, gas flow of 175,000 scf and methane flow of 49,000 ± 30,000 scf was measured. Since at all times during these 68 hours, the well pressure was more than double the pressure downstream of the choke, in the absence of direct measurements, emissions would be estimated based on the equation:

$$FRv\ (ft^3/hr) = 1.27*10^5*A * (187.08*T_u)^{0.5}$$

Where:
FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

For this completion, using T_u=100°F (assumed value), and a choke settings of 14/64" for 1 hr, 16/64" for 6 hr, 17/64" for 6 hr, 18/64" for 1 hr, 19/64" for 1 hr, 20/64" for 33 hr, 21/64" for 6 hr, 22/64" for 5 hr, 23/64" for 1 hr, 24/64" for 3 hr, 25/64" for 2 hr, 26/64" for 1 hr, 27/64 for 2 hr:

Flow = 106,0800 scf at the sonic flow conditions (311K and an assumed pressure of 100 psia)

Converting this flow to standard cubic feet (scf, 60°F, 1 atm) leads to an estimated flow of 667,000 scf. If this was assumed to be 25% methane (approximately the average of an assumed initial value of 0% and a final value of approximately 50%), emissions of methane would be 166,000 scf/h.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	49,000 ± 30,000 scf	170,000 scf
Total (based on centerline gas velocity measurements)	49,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	39,000 ± 30,000 scf	

Potential emissions:

Potential emissions = actual emissions

Rocky Mountain Completion 6 Data Report

Well information
Company: RM-B

Surface Equipment Configuration
Flowback went to a gas-buster tank. This tank was equipped, by the Study Team, with a temporary plastic cover and a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis. Flowback lasted for 23.7 hours.

Flowback timeline
Hours 0-24: Flow to gas-buster in an open tank.

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on open top tank: 64,000 scf

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
2 hours 40 min	Grab	N.D.
3 hours 35 min	Grab	6.10
4 hours 32 min	Grab	22.77
5 hours 36 min	Grab	55.23
6 hours 30 min	Grab	57.67
7 hours 33 min	Grab	73.92
8 hours 33 min	Grab	59.03
9 hours 21 min	Grab	70.49

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 6 found in the study database. The data are summarized in Figure RM6-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 6 found in the study database.

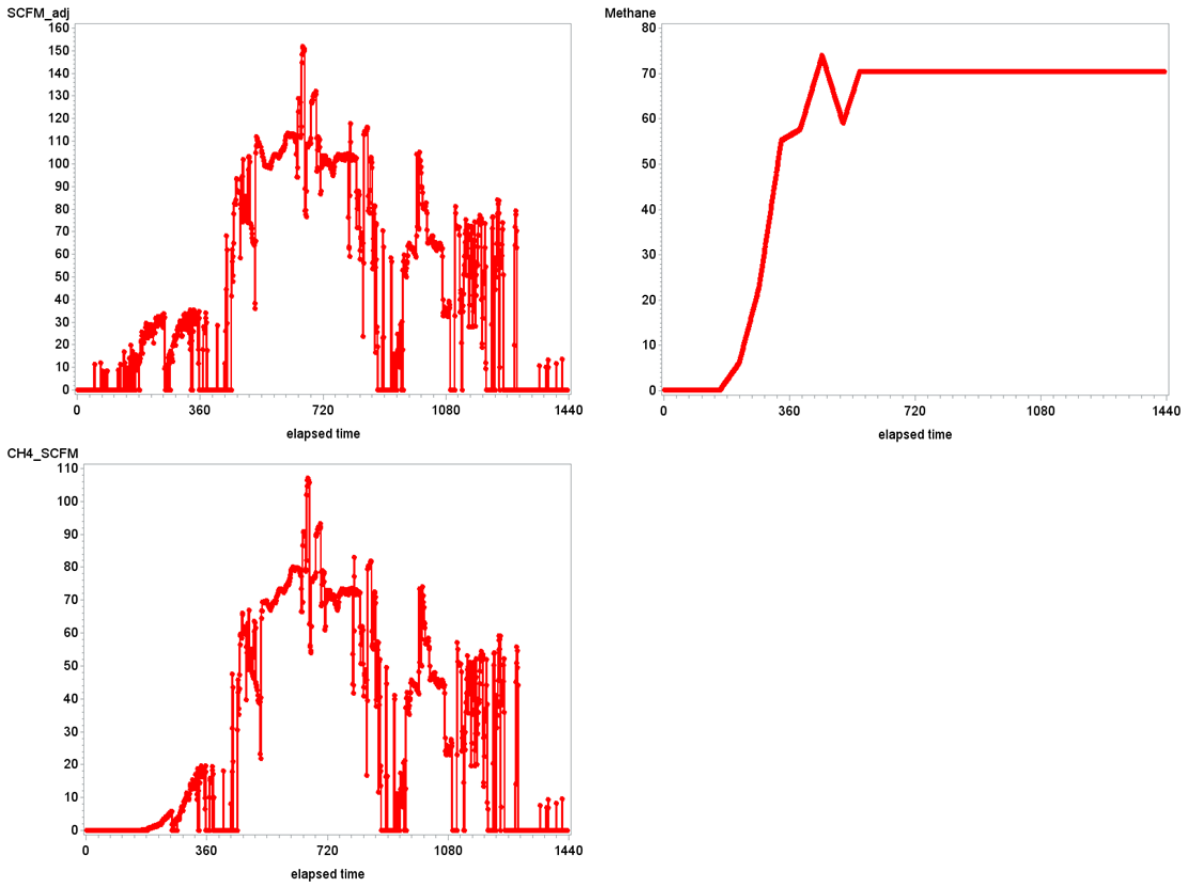
Emissions estimate = 42,000 ± 1,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 4,200
Combined uncertainty = ± 4,000

Figure RM6-1 Flowback into open-top gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 64,000 ft^3 over 1,421 minutes (23.7 hours)
Cumulative total methane: 42,000 ft^3 over 1,421 minutes (23.7 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [41,100 – 43,500]



Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	42,000 ± 4,000 scf	NA
Total (based on centerline gas velocity measurements)	42,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	34,000 ± 3,000scf	

Potential emissions:

Potential emissions = actual emissions

Rocky Mountain Completion 7 Data Report

Well information
Company: RM-C

Surface Equipment Configuration
Initial flowback went to a vented tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis.

After the initial period, the flow was sent to a separator. Gas from the separator was sent to a flare. Liquid from the separator was sent to the same vented flowback tank as the initial flow. Flow rates of gases vented from the liquids continued to be measured through the temporary stacks and grab samples were taken for composition analysis. The flowback lasted 4.8 hours.

Flowback timeline
Hours 0-5: Flow to vented tank then flow sent to separator; gas from separators to flare and fluids sent to same vented flowback tank as the initial flow

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on vented tank: 81scf

Data from completion report
Gas from separators (to flare): 30,000 scf

Gas Samples
No gas samples available – gas was assumed to be 50% (vol) methane, based on completions after this completion (Rocky Mountain Completions 8 and 10), flowing back to the same tank.

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was assumed to be 50 vol %. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 7 found in the study database.

Emissions estimate = 40 scf

Emissions from gas sent to flare:

A total of 30,000 scf of gas was sent to the flare. An estimate of methane sent to the flare would be to assume that the gas, for the entire period, was the composition of gas that had the highest percentage of methane of the samples collected from the same well pad (presumably gas from the separator would, on average, be higher in methane than the gas from the separator blowdown liquid, diluted by air in the flowback tank)

30,000 scf * 0.73 mol fraction methane = 22,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

22,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 440 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	40 scf	
Emissions from flare		440 scf
Total (based on centerline gas velocity measurements)	500 scf	
Total (based on estimated average gas velocity – see Appendix C)	500 scf	

Potential emissions:

22,000 scf sent to flare + 40 scf from vented tank = 22,040 scf methane

Rocky Mountain Completion 8 Data Report

Well information
Company: RM-C

Surface Equipment Configuration
Initial flowback went to a vented tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis.

After the initial period, the flow was sent to a separator. Gas from the separator was sent to a flare. Liquid from the separator was sent to the same vented flowback tank as the initial flow. Flow rates of gases vented from the liquids continued to be measured through the temporary stacks and grab samples were taken for composition analysis.

Flowback timeline
Hours 0-15: Flow to vented tank then flow sent to separator; gas from separators to flare and fluids sent to same vented flowback tank as the initial flow

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on vented tank: 15,000 scf

Data from completion report
Gas from separators (to flare): 596,000 scf

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
2 hours 49 min	Grab	4.41
2 hours 54 min	Grab	3.07
5 hours 34 min	Grab	9.51
5 hours 44 min	Grab	18.48
7 hours 14 min	Grab	73.41
10 hours 49 min	Grab	64.16
10 hours 14 min	Grab	33.44

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 8 found in the study database. The data are summarized in Figure RM8-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 8 found in the study database.

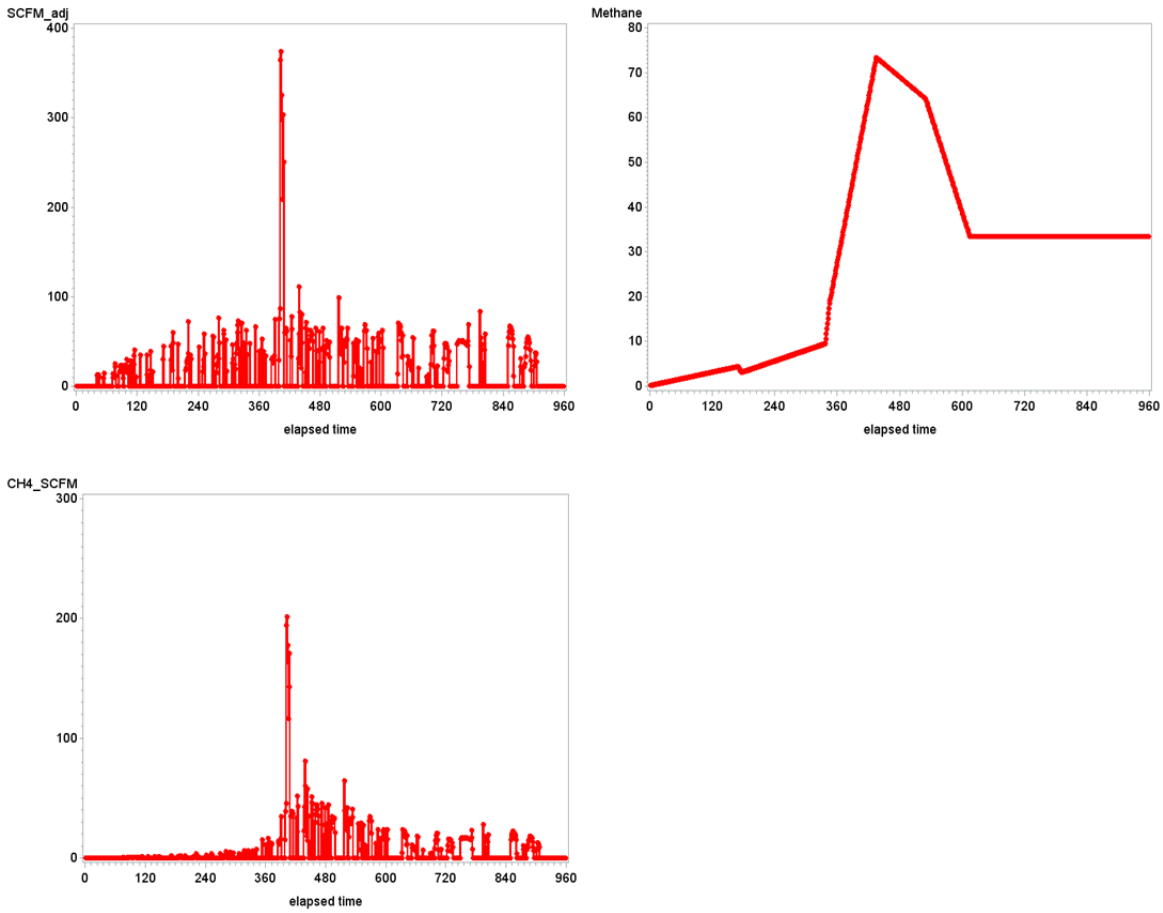
Emissions estimate = 6,000 ± 2,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 600
Combined uncertainty = ± 2,000

Figure RM8-1 Flowback into gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 15,100 ft^3 over 906 minutes (15.1 hours)
Cumulative total methane: 6,000 ft^3 over 959 minutes (15.1 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [4,190 – 7,190]



Emissions from gas sent to flare:
A total of 596,000 scf of gas was sent to the flare. An estimate of methane sent to the flare would be to assume that the gas, for the entire period, was the composition of gas that had the highest percentage of methane (presumably gas from the separator would, on average, be higher in methane than the the gas from the separator blowdown liquid, diluted by air in the flowback tank)

596,000 scf * 0.73 mol fraction methane = 435,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

435,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 9,000 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	6,000 ±2,000 scf	
Emissions from flare		9,000 scf
Total (based on centerline gas velocity measurements)	15,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	14,000 ± 2,000 scf	

Potential emissions:

435,000 scf sent to flare + 5,000 scf from vented tank = 440,000 scf methane

Rocky Mountain Completion 9 Data Report

Well information
Company: RM-C

Surface Equipment Configuration
Initial flowback went to a vented tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis.

After the initial period, the flow was sent to a separator. Gas from the separator was sent to a flare. Liquid from the separator was sent to the same vented flowback tank as the initial flow. Flow rates of gases vented from the liquids continued to be measured through the temporary stacks and grab samples were taken for composition analysis. The flowback lasted 21 hours.

Flowback timeline
Hours 0-21: Flow to vented tank then flow sent to separator; gas from separators to flare and liquids sent to same vented flowback tank as the initial flow

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on vented tank: 99,000 scf

Data from completion report
Gas from separators (to flare): 293,600 scf

Gas Samples
No gas samples available – gas was assumed to be 50% (vol) methane, based on completions immediately before and after (Rocky Mountain Completions 8 and 10), flowing back to the same tank.

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was assumed to be 50 vol %. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 9 found in the study database. The data are summarized in Figure RM9-1.

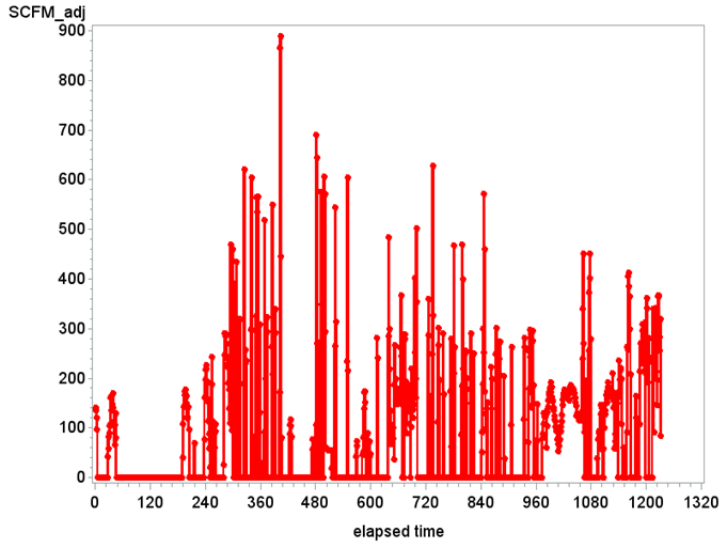
Emissions estimate = 50,000 scf

A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 5,000
Combined uncertainty = ± 5,000

Figure RM9-1 Flowback into gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 99,000 ft^3 over 1260 minutes (21 hours)



Emissions from gas sent to flare:
A total of 293,600 scf of gas was sent to the flare. An estimate of methane sent to the flare would be to assume that the gas, for the entire period, was the composition of gas that had the highest percentage of methane of the samples collected from the same well pad (presumably gas from the separator would, on average, be higher in methane than the gas from the separator blowdown liquid, diluted by air in the flowback tank)

293,600 scf * 0.73 mol fraction methane = 214,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

214,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 4,300 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	50,000 ± 5,000scf	
Emissions from flare		4,300 scf
Total (based on centerline gas velocity measurements)	54,000 scf	
Total (based on estimated average gas velocity – see Appendix C)	44,000 ± 4,000 scf	

Potential emissions:

214,000 scf sent to flare + 40,000 scf from vented tank = 254,000 scf methane

Rocky Mountain Completion 10 Data Report

Well information
Company: RM-C

Surface Equipment Configuration
Initial flowback went to a vented tank. This tank was equipped, by the Study Team, with a temporary stack. Flow rates were measured through the temporary stack and grab samples were taken for gas composition analysis.

After the initial period, the flow was sent to a separator. Gas from the separator was sent to a flare. Liquid from the separator was sent to the same vented flowback tank as the initial flow. Flow rates of gases vented from the liquids continued to be measured through the temporary stacks and grab samples were taken for composition analysis. The flowback lasted 34.1 hours.

Flowback timeline
Hours 0-34: Flow to vented tank then flow sent to separator; gas from separators to flare and liquids sent to same vented flowback tank as the initial flow

Completion flowback total gas flows
Data from emission measurements
Total gas flow through temporary stack on vented tank: 120,000 scf

Data from completion report
Gas from separators (to flare): 545,000 scf

Gas Samples
Open top tank gas samples (from well head)

Start time of sample (time from start of completion)	*Sample duration*	*Volume % methane*
12 hours 04 min	Grab	27.73
15 hours 04 min	Grab	51.76
17 hours 00 min	Grab	60.38
20 hours 00 min	Grab	43.00

Emission calculations

Emissions during flow to open top tank:

Volumetric flow of vent gas was recorded each minute based on the measured centerline velocity, multiplied by the area of the stack (not accounting for differences between centerline and average gas velocities – see Appendix C). For each one-minute record of volumetric flow, a percentage of methane was determined using linear interpolation between the most recent grab sample composition measurement before and the most recent grab sample composition measurement after the flow measurement. These calculations are documented in the Excel spreadsheet file for Rocky Mountain Completion 10 found in the study database. The data are summarized in Figure RM10-1.

To assess the magnitude of the uncertainty associated with using linearly interpolated methane concentrations, two sensitivity analyses were performed. In one sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the lower of the most recent composition measurement before and the most recent composition measurement after the flow measurement. In a second sensitivity analysis, the methane concentration for each minute of flow data was assumed to be the higher of the most recent composition measurement before and the most recent composition measurement after the flow measurement. For the estimate of the lower bound on emissions, it was assumed that the methane percentage in the gas at the start of the completion was equal to half of the detection limit (0.18%, equal to half of the smallest concentration recorded in the chromatographic analyses (0.36%) during the entire study) and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. For the estimate on the higher bound on concentration, the methane concentration at the start of the completion was assumed to be equal to the initial concentration measurement and it was assumed that the final gas composition persisted from the time of the measurement until the end of the completion. These two sensitivity analyses provide a quantification of the uncertainty associated with using discrete, rather than continuous methane analyses. These calculations are also documented in the Excel spreadsheet file for Rocky Mountain Completion 10 found in the study database.

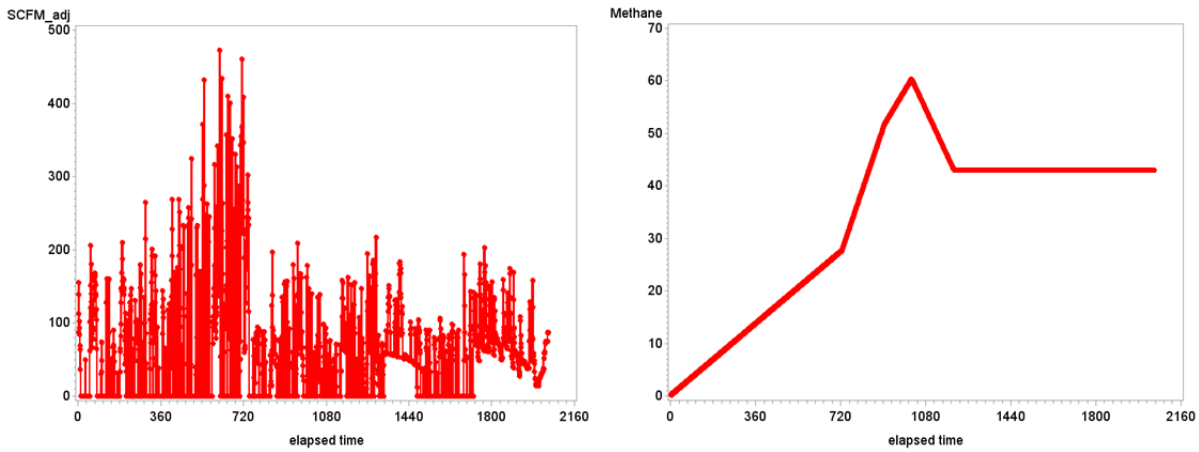
Emissions estimate = 39,000 ± 10,000 scf

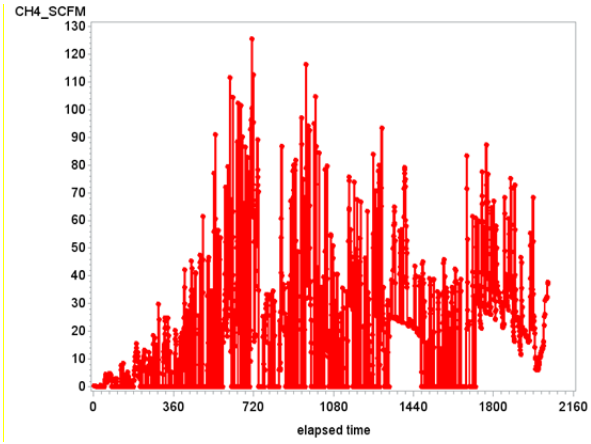
A 10% uncertainty was estimated for the volumetric flow measurement. This uncertainty is combined with the uncertainty due to non-continuous composition measurements, assuming that the two uncertainties are independent.

Flow rate uncertainty = ± 3,900
Combined uncertainty = ± 11,000

Figure RM10-1 Flowback into gas buster tank; elapsed time in minutes is shown on horizontal axis; Methane units are mol percent; Scfm units are standard cubic feet of gas per minute; CH4_scfm units are standard cubic feet of methane per minute.

Cumulative total gas: 120,000 ft^3 over 2,046 minutes (34.1 hours)
Cumulative total methane: 39,000 ft^3 over 2,046 minutes (34.1 hours)
Two other estimates based on using the upper and lower ends of possible methane percentage: [28,000 – 46,700]





Emissions from gas sent to flare:
A total of 545,000 scf of gas was sent to the flare. An estimate of methane sent to the flare would be to assume that the gas, for the entire period, was the composition of gas that had the highest percentage of methane (presumably gas from the separator would, on average, be higher in methane than the the gas from the separator blowdown liquid, diluted by air in the flowback tank)

545,000 scf * 0.60 mol fraction methane = 327,000 scf methane sent to flare

The emissions from the flare are estimated as 2% of the methane sent to the flare (assuming a 98% combustion efficiency for the flare)

327,000 scf sent to flare * (1-0.98) fraction released assuming 98% combustion efficiency = 6,500 scf.

Summary of methane emission measurements and estimates using standard methods

Source	*Measurement*	*Estimate*
Emissions during flow to open top tank	39,000 ±11,000 scf	
Emissions from flare		6,500 scf
Total (based on centerline gas velocity measurements)	45,500 scf	
Total (based on estimated average gas velocity – see Appendix C)	37,700 ± 9,000 scf	

Potential emissions:

327,000 scf sent to flare + 31,200 scf from vented tank = 358,200 scf methane

Appendix I

Aerodyne Mobile Van

Dual Tracer Performance Evaluation

Downwind Tracer Ratio Measurements at Natural Gas Production Sites

Measurement Description and Objective

The overall goal of the sampling upwind and downwind of natural gas production sites was to perform instantaneous and time integrated measurements of the total methane emissions from natural gas production sites. The resulting emissions measurements represent a site aggregated emission estimate and complement on-site measurements of emissions from multiple emission sources. The objective of these downwind measurements was to determine whether the direct source measurements were capturing all significant sources of emissions, and to assess the magnitude of emissions of methane that were not directly measured using the methods employed in this study, such as emissions that are part of the flue gas of devices such as compressors.

The measurements employed tracer release methodologies to quantify the total methane emission rate coming from a site. Tracer species were emitted at a controlled rate, on site, at locations as close as possible to methane releases. The tracer species were measured at downwind locations (100 m to more than 1 km). Upwind tracer concentrations were measured, as required, if downwind mobile sampling indicated that tracer concentrations did not return to zero baseline values outside of detected plumes. If it is assumed that the tracer disperses in a manner equivalent to the methane, the ratio of the far field concentrations of the tracer gas and the sample gas will be the same as the ratios of their emission rates. Thus, the unknown methane emission rate is obtained from the well known tracer release rate and the ratio of the methane concentration to the tracer concentration detected sufficiently far downwind:

Methane emission rate = Tracer emission rate * (downwind – upwind concentration of methane) / (downwind – upwind concentration of tracer)

The primary assumption underlying the use of the tracer flux ratio approach in this work is the assumption of equivalent dispersion of the tracer and methane. Therefore, a series of experiments were conducted to assess the accuracy of the equivalent dispersion assumptions.

Figures I-1 and I-2 show results from performance evaluations of the dual tracer release method. The Figures display the downwind concentration distributions measured by the mobile van for two co-located tracer releases and methane emissions from a natural gas production site. Also shown are the second by second correlations between the tracer N_2O and methane, and between the tracer N_2O and the tracer acetylene. The slope of the best fit line correlating the concentrations is the estimated ratio of emission rates of the two compounds. The ratio of emission rates, estimated from the concentratrions in the downwind plumes, can be compared to the known ratio of emission rates of the N_2O and acetylene tracers. This comparison was done multiple times with varying degrees of separation between the tracer releases, ranging from co-location of the tracer releases to separation of the tracer releases by up to 30 m. The relative placement of the two tracers is shown in Figure I-3. Figure I-3 shows a horizontal grid of the

sampling site. The green diamond shows the location of one tracer release point, and the letters A, B, C and Z indicate locations of the second tracer release points. All tracers in this case were released at approximately 3 m above ground level. Tracers were co-located (release A) and separated by 15-30 m (releases B, C, and Z).

Measurements of the tracers were made at distances downwind ranging from 50 m to 900 m, and based on these measurements, the emission rate of acetylene was estimated, based on the emission rate of N_2O and the relative concentrations of N_2O and acetylene downwind. The percentage difference between predicted acetylene emission rate (based on downwind concentrations) and the known tracer release rate for acetylene was calculated. The results, shown in Figure I-4, indicate that for co-located tracers (release A), estimated fluxes are approximately 15% different than measured release rates when measurements were made 100 m downwind. At 200 m or further downwind, however, differences between predicted and measured fluxes were typically only a few percent (see Figures I-3 and I-4). When tracer releases were not co-located, the differences between predicted and measured fluxes were ±25% when tracer concentration measurements were made 200 m downwind. As downwind measurement distance increased to 500 m, the difference between predicted and measured fluxes decreased to a few percent (release Z).

Based on these data, downwind measurements were made 500 m or more downwind, whenever suitable access points were available. In addition, tracers were positioned as close to the methane release points as possible. Based on these procedures and the data reported in Figure I-4, uncertainties in the downwind measurements of methane fluxes will be reported as approximately ±20%.

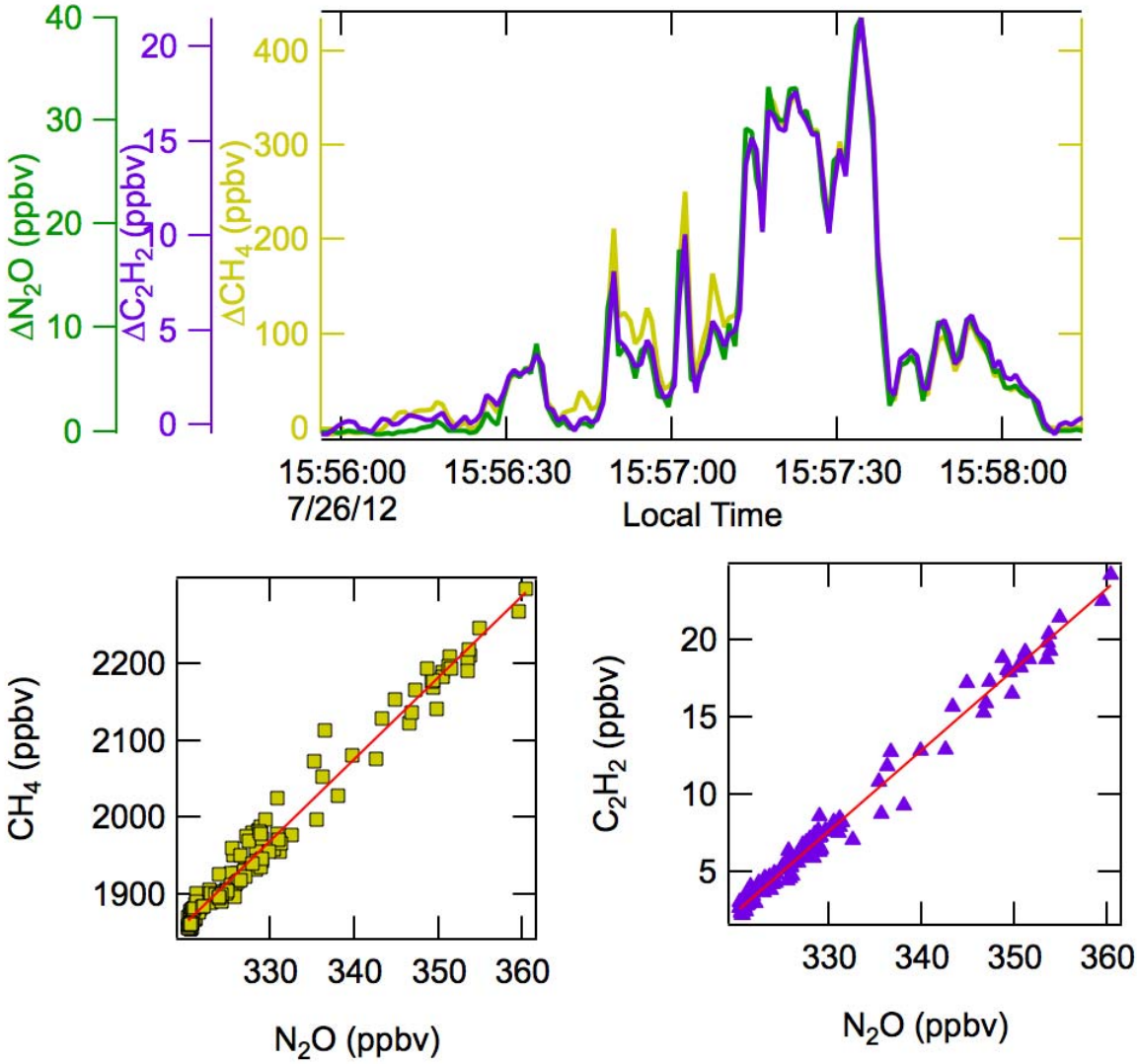


Figure I-1. Measurements of acetylene, N_2O and methane, measured by the mobile van downwind of a natural gas production site with co-located tracer releases (upper). Measurements were made over a 2 minute downwind transect. Lower plots show second by second correlation of N_2O tracer and methane (left) and correlation of concentrations of the two tracers (right). The ratio of concentrations of acetylene/N_2O is within 3% of the ratio of the measured tracer emission rates.

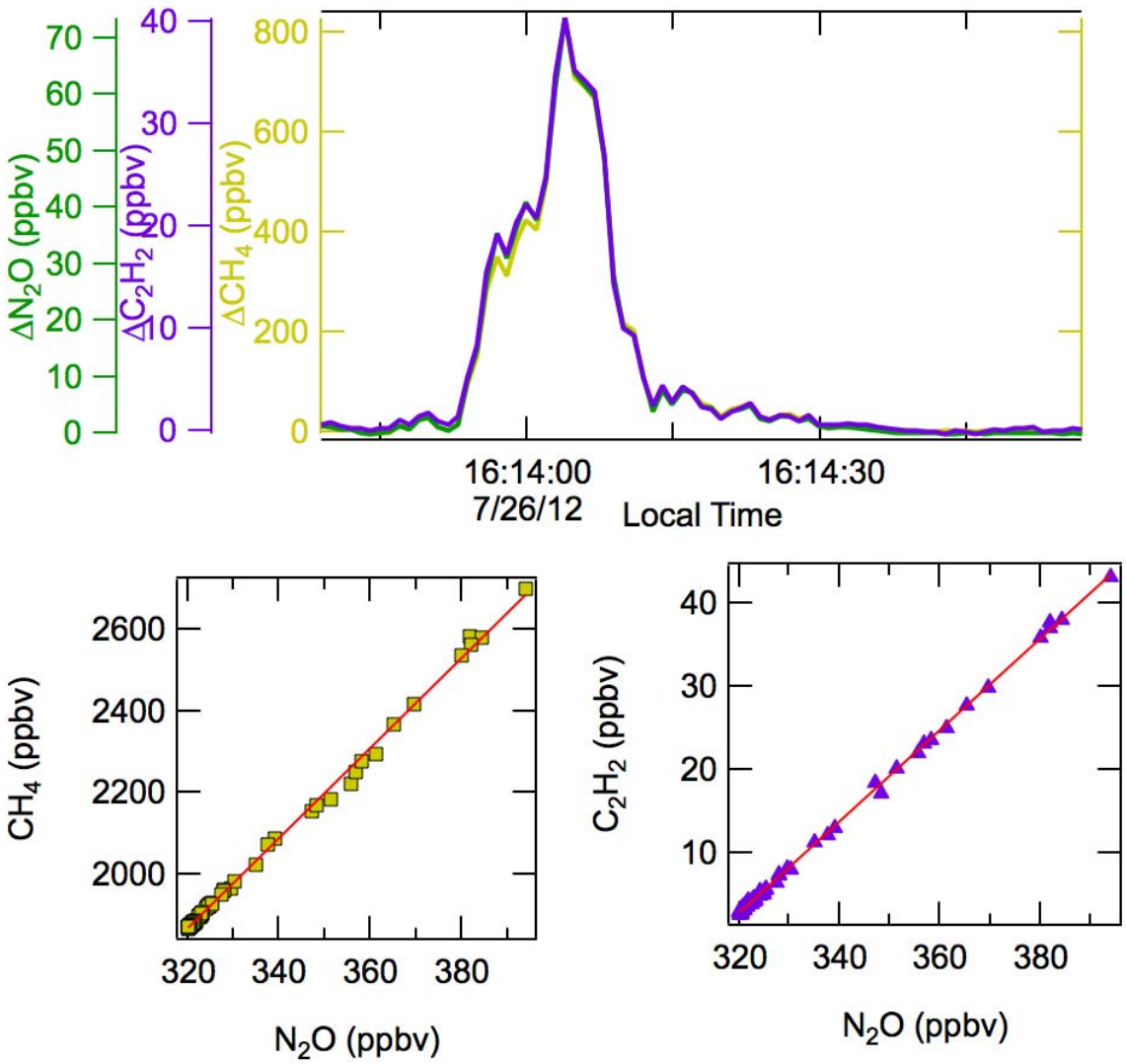


Figure I-2. Measurements of acetylene, N_2O and methane, measured by the mobile van downwind of a natural gas production site with co-located tracer releases (upper). Measurements were made over a 2 minute downwind transect. Lower plots show second by second correlation of N_2O tracer and methane (left) and correlation of concentrations of the two tracers (right). The ratio of concentrations of acetylene/N_2O is within 2% of the ratio of the measured tracer emission rates.

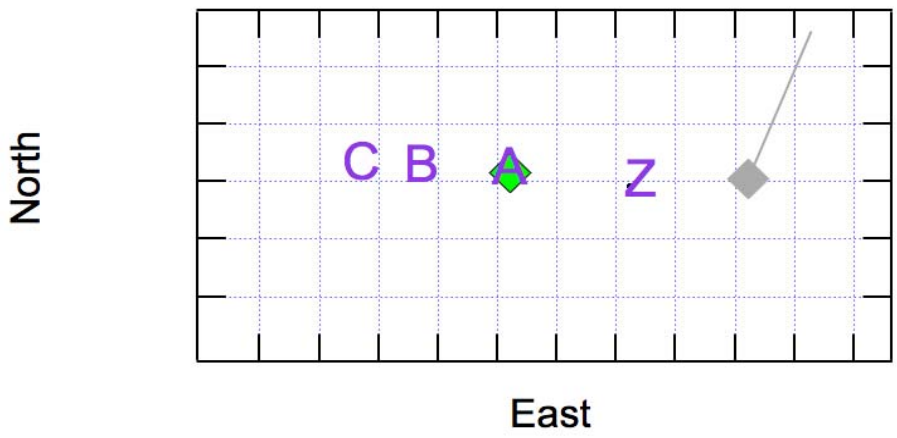


Figure I-3. Locations of dual tracer releases on a horizontal grid. Each grid square is 10 m by 10 m; green diamond represents the release point of one tracer; letters A, B, C and Z represent the release of the second tracer. Gray diamond represents the location of the meteorological station and the line from the gray triangle represents the wind direction.

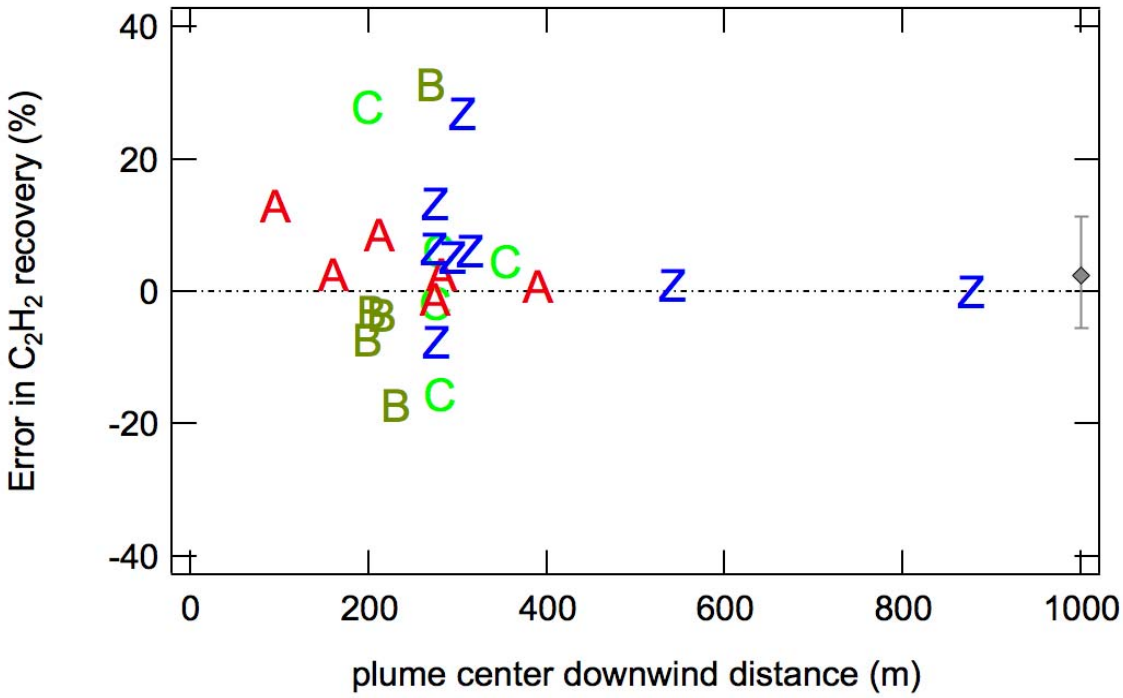


Figure I-4. Difference (as % error) between the ratio of the emission rates predicted based on downwind concentration measurements and the ratio of measured emission rates of the two tracers. Letters indicate relative location of tracer releases; position along the vertical axis represents the distance downwind at which measurements were made (multiple measurements were made for each configuration of tracer release positions.

Appendix J

Description of production sites at which downwind measurements were made

Production Site Mid-Continent 1 Data Report

Well information
Company: A

Surface Equipment Configuration
Two wells connected to three separators, gas from the separator goes to sales. There is 1 combustor, 2 compressors, 2 water tanks, 4 condensate tanks, 1 demulsifier, 1 salt inhibitor, and 2 corrosion inhibitors.
Pneumatic Controllers: 9 intermittent, 0 High bleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from piping and regulator in compressor.

Production rates:
Gas: 0.9 million scf/day (70.89% methane)
Oil: 47.1 bbl/day
Water: 423.0 bbl/day

Site age: 0.9 yr

Site emissions calculations
Pneumatic controllers:
9 pneumatics on site (0 randomly selected), using average emission rate for the region, 0.157 scfm methane.
Pneumatic leaks = 9 * (0.1565) scfm methane = 1.409 scfm methane

Chemical injection pumps:
1 chemical injection pump was found during the measurements.
Chemical injection pumps leaks = 1 * (0.002) scf methane = 0.002 scfm methane

Compressors:
For a compressor that delivers 0.88 MMscf/day (36,666 scf/hr = 1,624 lb/hr) of natural gas from 75 psig to 175 psig (assumed sales line pressure). A Δh of 60 BTU/lb for those conditions, assuming a compressor efficiency of 40% and a methane emission of 0.001 kg of methane per MMBTU
1,624 lb/hr * 60 BTU/lb = 97,442 BTU/hr; LHV of 243,607 BTU/hr; and a HHV of 270,674 BTU/hr or 0.27 MMBTU/hr
0.27 MMBTU/hr * 0.001 kg CH4 = $2.706*10^{-4}$ kg/hr methane, or $2.23*10^{-4}$ scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (60ºF, 75 psig), an API gravity of 41.30º, a gas that is 70.89% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 47.1 BBL/day = 2733.0 scf/day = 1.90 scf/min

Assume 98% combusted in flare = 0.038 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60ºF, 75 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 70.89% methane

Separator pressure is 75 psig or 90 psia; $X_{methane}$ = 90/670,000 = 0.0001 mol fraction

If the gas in the separator is 70.89% methane, the mol fraction methane would be 0.0001. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 0.8 g mol of methane per bbl (0.0001* 8830 g mol). This is 0.7 scf methane per bbl of water. 0.7 scf/BBL * 423.000 BBL/day = 307.11 scf/day = 0.213 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.231 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.038 scf/min
Emissions from water tank		0.21 scf/min
Emissions from pneumatic controllers		1.41 scf/min
Emissions from chemical injection pumps		0.002 scf/min
Emissions from directly measured sources	0.231 scf/min	
Emissions estimated based on emission factors (excluding tanks)		1.41 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	1.89 scf/min	
Percentage of gas produced	0.31%	

Production Site Mid-Continent 2 Data Report

Well information
Company: A

Surface Equipment Configuration
One well connected to one separator, gas from separator goes to sales. There is one combustor, 1 compressor, 1 water tank, and one condensate tank.
Pneumatic Controllers: 9 intermittent, 0 High bleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from connection and compressor regulators.

Production rates:
Gas: 0.3 million scf/day (78.07% methane)
Oil: 0.0 bbl/day
Water: 20.0 bbl/day

Site age: 0.7 yr

Site emissions calculations
Pneumatic controllers:
9 pneumatics on site (3 randomly selected), average emission rate
Pneumatic leaks = 9 * (0.324) scf methane = 2.91 scfm methane

Compressors:
For a compressor that delivers 0.28 MMscf/day (11,667 scf/hr = 517 lb/hr) of natural gas from 34 psig to 175 psig (assumed sales line pressure). A Δh of 50 BTU/lb for those conditions, assuming a compressor efficiency of 40% and a methane emission of 0.001 kg of methane per MMBTU
517 lb/hr * 50 BTU/lb = 25,837 BTU/hr; LHV of 64,593 BTU/hr; and a HHV of 71,770 BTU/hr or 0.07 MMBTU/hr
0.07 MMBTU/hr * 0.001 kg CH4 = $7.177*10^{-5}$ kg/hr methane, or $5.91*10^{-5}$ scfm methane

Tanks:
Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60ºF, 34 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 78.07% methane

Separator pressure is 34 psig or 49 psia; $X_{methane}$ = 49/670,000 = 0.0001 mol fraction

If the gas in the separator is 78.07% methane, the mol fraction methane would be 0.0001. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 0.5 g mol of methane per bbl (0.0001* 8830 g mol). This is 0.4 scf methane per bbl of water.
0.4 scf/BBL * 20.000 BBL/day = 8.71 scf/day = 0.006 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.012 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.000 scf/min
Emissions from water tank		0.006 scf/min
Emissions from pneumatic controllers		2.91 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.012 scf/min	
Emissions estimated based on emission factors (excluding tanks)		2.91 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	2.93 scf/min	
Percentage of gas produced	1.51%	

Production Site Mid-Continent 3 Data Report

Well information
Company: A

Surface Equipment Configuration
3wells connected to 4 separators, gas from separators goes to sales. There is 1 combustor, 3 tanks, 3 compressors, 2 water tanks, 1 condensate tanks, 1 demulsifier, 1 salt inhibitor, and 3 corrosion inhibitors.
Pneumatic Controllers: 10 intermittent, 0 High bleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from valves, holes and pressure regulator in separator.

Production rates:
Gas: 2.1 million scf/day (77.19% methane)
Oil: 43.3 bbl/day
Water: 385.0 bbl/day

Site age: 0.8 yr

Site emissions calculations
Pneumatic controllers:
10 pneumatics on site (4 randomly selected), average emission rate
Pneumatic leaks = 10 * (0.436) scf methane = 4.361 scfm methane

Compressors:
For a compressor that delivers 2.07 MMscf/day (86,250 scf/hr = 3,820 lb/hr) of natural gas from 75 psig to 175 psig (assumed sales line pressure). A Δh of 60 BTU/lb for those conditions, assuming a compressor efficiency of 40% and a methane emission of 0.001 kg of methane per MMBTU
3,820 lb/hr * 60 BTU/lb =229,000 BTU/hr; LHV of 573,000 BTU/hr; and a HHV of 636,700 BTU/hr or 0.64 MMBTU/hr
0.64 MMBTU/hr * 0.001 kg CH4 = $6.37*10^{-4}$ kg/hr methane, or $5.24*10^{-4}$ scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (60ºF, 75 psig), an API gravity of 42.80º, a gas that is 77.19% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 43.3 BBL/day = 2513.1 scf/day = 1.745 scf/min
Assume 98% combusted in flare = 0.035 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60ºF, 75 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 77.19% methane

Separator pressure is 75 psig or 90 psia; $X_{methane}$ = 90/670,000 = 0.0001 mol fraction

If the gas in the separator is 77.19% methane, the mol fraction methane would be 0.0001. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 0.9 g mol of methane per bbl (0.0001* 8830 g mol). This is 0.8 scf methane per bbl of water. 0.8 scf/BBL * 385.000 BBL/day = 304.36 scf/day = 0.211 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.292 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.035 scf/min
Emissions from water tank		0.211 scf/min
Emissions from pneumatic controllers		4.36 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.292 scf/min	
Emissions estimated based on emission factors (excluding tanks)		4.36 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	4.90 scf/min	
Percentage of gas produced	0.34%	

Production Site Mid-Continent 4 Data Report

Well information
Company: A

Surface Equipment Configuration
2 wells connected to 5 separators, gas from separators goes to sales. There is 1 combustor, 7 tanks, 3 compressors, 1 demulsifier, 1 salt inhibitor, and 1 corrosion inhibitor.
Pneumatic Controllers: 11 intermittent, 0 High bleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from fittings

Production rates:
Gas: 0.03 million scf/day (74.23% methane)
Water: 2697.0 bbl/day

Site age: 0.01 yr

Site emissions calculations
Pneumatic controllers:
11 pneumatics on site (2 randomly selected), average emission rate
Pneumatic leaks = 11 * (0.110) scf methane = 1.210 scfm methane

Compressors:
For a compressor that delivers 0.03 MMscf/day (1,250 scf/hr = 55 lb/hr) of natural gas from 72 psig to 175 psig (assumed sales line pressure). A Δh of 60 BTU/lb for those conditions, assuming a compressor efficiency of 40% and a methane emission of 0.001 kg of methane per MMBTU
55 lb/hr * 60 BTU/lb = 3,320 BTU/hr; LHV of 8,300 BTU/hr; and a HHV of 9,230 BTU/hr or 0.01 MMBTU/hr
0.01 MMBTU/hr * 0.001 kg CH4 = $9.22*10^{-6}$ kg/hr methane, or $7.60*10^{-6}$ scfm methane

Tanks:
Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60ºF, 72 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 74.23% methane

Separator pressure is 72 psig or 87 psia; $X_{methane}$ = 87/670,000 = 0.0001 mol fraction

If the gas in the separator is 74.23% methane, the mol fraction methane would be 0.0001. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 0.9 g mol of methane per bbl (0.0001* 8830 g mol). This is 0.7 scf methane per bbl of water.
0.7 scf/BBL * 2697.000 BBL/day = 1980 scf/day = 1.38 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.329 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.000 scf/min
Emissions from water tank		1.38 scf/min
Emissions from pneumatic controllers		1.21 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.329 scf/min	
Emissions estimated based on emission factors (excluding tanks)		1.21 scf/min
Emissions from flare		Methane included in tanks estimate
Total	2.92 scf/min	
Percentage of gas produced	14.%	

Production Site Mid-Continent 5 Data Report

Well information
Company: A

Surface Equipment Configuration
2 wells connected to five separators, gas from separators goes to sales. There is 1 combustor, 3 tanks, 2 compressors, 1 water tank, and 2 condensate tanks.
Pneumatic Controllers: 12 intermittent, 0 High bleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from unions, valves, and fittings.

Production rates:
Gas: 0.9 million scf/day (79.32% methane)
Oil: 32.4 bbl/day
Water: 122.0 bbl/day

Site age: 1.1 yr

Site emissions calculations
Pneumatic controllers:
12 pneumatics on site (6 randomly selected), average emission rate
Pneumatic leaks = 12 * (0.704) scf methane = 8.450 scfm methane

Compressors:
For a compressor that delivers 0.91 MMscf/day (37,917 scf/hr = 1,679 lb/hr) of natural gas from 91 psig to 175 psig (assumed sales line pressure). A Δh of 60 BTU/lb for those conditions, assuming a compressor efficiency of 40% and a methane emission of 0.001 kg of methane per MMBTU
1,679 lb/hr * 60 BTU/lb = 100,765 BTU/hr; LHV of 251,911 BTU/hr; and a HHV of 279,902 BTU/hr or 0.28 MMBTU/hr
0.28 MMBTU/hr * 0.001 kg CH4 = $2.80*10^{-4}$ kg/hr methane, or $2.31*10^{-4}$ scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (60ºF, 91 psig), an API gravity of 41.50º, a gas that is 79.32% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 32.4 BBL/day = 1881.5 scf/day = 1.31 scf/min
Assume 98% combusted in flare = 0.026 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60ºF, 91 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 79.32% methane

Separator pressure is 91 psig or 106 psia; $X_{methane}$ = 106/670,000 = 0.0002 mol fraction

If the gas in the separator is 79.32% methane, the mol fraction methane would be 0.0001. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.1 g mol of methane per bbl (0.0001* 8830 g mol). This is 1.0 scf methane per bbl of water. 1.0 scf/BBL * 122. BBL/day = 117 scf/day = 0.081 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.337 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.026 scf/min
Emissions from water tank		0.081 scf/min
Emissions from pneumatic controllers		8.45 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.337 scf/min	
Emissions estimated based on emission factors (excluding tanks)		8.45 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	8.89 scf/min	
Percentage of gas produced	1.41%	

Production Site Rocky Mountains 1 Data Report

Well information
Company: B

Surface Equipment Configuration
8 wells connected to 4 separators, gas from separator goes to sales. There is one combustor, 3 tanks, and 1 water tank.
Pneumatic Controllers: 8 intermittent, 0 High bleed, 4 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from thermostat.

Production rates:
Gas: 0.05 million scf/day (81.89% methane)
Oil: 1.8 bbl/day
Water: 3.8 bbl/day

Site age: 7.0 yr

Site emissions calculations
Pneumatic controllers:
12 pneumatics on site (0 randomly selected), average emission rate for the region 0.015 scf/min
Pneumatic leaks = 12 * (0.015) scf methane = 0.185 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 50.97º, a gas that is 81.89% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 1.8 BBL/day = 101.6 scf/day = 0.071 scf/min
Assume 98% combusted in flare = 0.001 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 81.89% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 81.89% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 2.0 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.7 scf methane per bbl of water.
1.7 scf/BBL * 3.85 BBL/day = 6.63 scf/day = 0.005 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.024 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.001 scf/min
Emissions from water tank		0.005 scf/min
Emissions from pneumatic controllers		0.185 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.024 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.185 scf/min
Emissions from flare		Methane included in tanks estimate
Total	0.215 scf/min	
Percentage of gas produced	1.0%	

Production Site Rocky Mountains 2 Data Report

Well information
Company: B

Surface Equipment Configuration
8 wells connected to 3 separators, gas from separator goes to sales. There is no combustor, 5 tanks, and 1 water tank.
Pneumatic Controllers: 2 intermittent, 0 High bleed, 1 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from unions, exhausts, and valve.

Production rates:
Gas: 0.495 million scf/day (74.54% methane)
Oil: 96.7 bbl/day
Water: 349.4 bbl/day

Site age: 0.0 yr

Site emissions calculations
Pneumatic controllers:
3 pneumatics on site (1 randomly selected, but no measured emission rate); using the average emission rate for the region, 0.015 scfm.
Pneumatic leaks = 3 * (0.015) scfm methane = 0.046 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 49.78º, a gas that is 74.54% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 96.7 BBL/day = 5609 scf/day = 3.90 scf/min

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 74.54% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 74.54% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.8 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 349.364 BBL/day = 548.25 scf/day = 0.381 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.103 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		3.90 scf/min
Emissions from water tank		0.381 scf/min
Emissions from pneumatic controllers		0.046 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.103 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.046 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	4.42 scf/min	
Percentage of gas produced	1.3%	

Production Site Rocky Mountains 3 Data Report

Well information
Company: B

Surface Equipment Configuration
1 well connected to 1 separator, gas from the separator goes to sales. There is 1 combustor, 4 tanks, and 1 water tank.
Pneumatic Controllers: 2 intermittent, 0 High bleed, 1 Low Bleed
Chemical injection pumps: none
Additional measured fugitive releases: from thermostat, piping, and vent hole on well head.

Production rates:
Gas: 0.001 million scf/day (76.43% methane)
Oil: 0.1 bbl/day
Water: 0.0 bbl/day

Site age: 2.0 yr

Site emissions calculations
Pneumatic controllers:
3 pneumatics on site (0 randomly selected), using average emission rate for the region, 0.015 scfm methane.
Pneumatic leaks = 3 * (0.015) scfm methane = 0.046 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 48.20º, a gas that is 76.43% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 0.1 BBL/day = 4.3 scf/day = 0.003 scf/min
Assume 98% combusted in flare = 0.000 scf/min methane

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.087 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.000 scf/min
Emissions from water tank		0.000 scf/min
Emissions from pneumatic controllers		0.046 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.087 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.046 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	0.134 scf/min	
Percentage of gas produced	20%	

Production Site Rocky Mountains 4 Data Report

Well information
Company: B

Surface Equipment Configuration
7 wells connected to 2 separators, gas from separator goes to sales. There is one combustor, 2 tanks, and 1 water tank.
Pneumatic Controllers: 4 intermittent, 0 High bleed, 2 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from fittings, and thermostat.

Production rates:
Gas: 0.0458 million scf/day (74.93% methane)
Oil: 1.7 bbl/day
Water: 1.8 bbl/day

Site age: 4.0 yr

Site emissions calculations
Pneumatic controllers:
6 pneumatics on site (1 randomly selected), average emission rate
Pneumatic leaks = 6 * (0.018) scf methane = 0.106 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 48.10º, a gas that is 74.93% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 1.7 BBL/day = 100. scf/day = 0.070 scf/min
Assume 98% combusted in flare = 0.001 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 74.93% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 74.93% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.8 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 1.795 BBL/day = 2.83 scf/day = 0.002 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.005 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.001 scf/min
Emissions from water tank		0.002 scf/min
Emissions from pneumatic controllers		0.106 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.005 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.106 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	0.115 scf/min	
Percentage of gas produced	0.4%	

Production Site Rocky Mountains 5 Data Report

Well information
Company: B

Surface Equipment Configuration
2 wells connected to 3 separators, gas from separator goes directly to sales. There is one combustor, 4 tanks, and 1 water tank.
Pneumatic Controllers: 14 intermittent, 0 High bleed, 7 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from fittings, and hole.

Production rates:
Gas: 0.138 million scf/day (74.54% methane)
Oil: 7.5 bbl/day
Water: 3.4 bbl/day

Site age: 5.9 yr

Site emissions calculations
Pneumatic controllers:
21 pneumatics on site (1 randomly selected), average emission rate
Pneumatic leaks = 21 * (0.003) scf methane = 0.055 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 48.25º, a gas that is 74.54% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 7.5 BBL/day = 437.6 scf/day = 0.304 scf/min
Assume 98% combusted in flare = 0.006 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 74.54% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 74.54% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.8 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 3.423 BBL/day = 5.37 scf/day = 0.004 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.029 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.006 scf/min
Emissions from water tank		0.004 scf/min
Emissions from pneumatic controllers		0.055 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.029 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.055 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	0.094 scf/min	
Percentage of gas produced	0.1%	

Production Site Rocky Mountains 6 Data Report

Well information
Company: B

Surface Equipment Configuration
6 wells
Pneumatic Controllers: 18 intermittent, 0 Hibleed, 9 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from fittings and valves.

Production rates:
Gas: 0.168 million scf/day (74.54% methane)
Oil: 8.6 bbl/day
Water: 4.4 bbl/day

Site age: 3.8 yr

Site emissions calculations
Pneumatic controllers:
27 pneumatics on site (0 randomly selected), using average emission rate for the region, 0.015 scfm methane.
Pneumatic leaks = 27 * (0.015) scf methane = 0.417 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 52.83º, a gas that is 74.54% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 8.6 BBL/day = 496.5 scf/day = 0.345 scf/min
Assume 98% combusted in flare = 0.007 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 74.54% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 74.54% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.8 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 4.447 BBL/day = 6.98 scf/day = 0.005 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.306 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.007 scf/min
Emissions from water tank		0.005 scf/min
Emissions from pneumatic controllers		0.417 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.306 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.417 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	0.735 scf/min	
Percentage of gas produced	0.63%	

Production Site Rocky Mountains 7 Data Report

Well information
Company: B

Surface Equipment Configuration
1 well connected to two separators, gas from separators goes to sales. There is one combustor, 3 tanks, 1 water tank.
Pneumatic Controllers: 8 intermittent, 0 High bleed, 4 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from fittings and valves.

Production rates:
Gas: 0.230 million scf/day (74.54% methane)
Oil: 7.5 bbl/day
Water: 8.7 bbl/day

Site age: 5.0 yr

Site emissions calculations
Pneumatic controllers:
12 pneumatics on site (0 randomly selected), using the average emission rate for the region, 0.015 scfm methane
Pneumatic leaks = 12 * (0.015) scfm methane = 0.185 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 51.85º, a gas that is 74.54% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 7.5 BBL/day = 436. scf/day = 0.303 scf/min
Assume 98% combusted in flare = 0.006 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 74.54% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 74.54% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.8 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 8.74 BBL/day = 13.7 scf/day = 0.010 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.070 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.006 scf/min
Emissions from water tank		0.010 scf/min
Emissions from pneumatic controllers		0.185 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.070 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.185 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	0.271 scf/min	
Percentage of gas produced	0.17%	

Production Site Rocky Mountains 8 Data Report

Well information
Company: B

Surface Equipment Configuration
1 well connected to 4 separators, gas from separator goes to sales. There is 1 combustor, 3 tanks, and 2 water tanks.
Pneumatic Controllers: 8 intermittent, 0 High bleed, 4 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from separator, fittings, and valves.

Production rates:
Gas: 0.230 million scf/day (76.19% methane)
Oil: 7.5 bbl/day
Water: 8.7 bbl/day

Site age: 5.0 yr

Site emissions calculations
Pneumatic controllers:
12 pneumatics on site (2 randomly selected), average emission rate
Pneumatic leaks = 12 * (0.007) scfm methane = 0.080 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 51.85º, a gas that is 76.19% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 7.5 BBL/day = 436.5 scf/day = 0.303 scf/min
Assume 98% combusted in flare = 0.006 scf/min methane

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 76.19% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 76.19% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.9 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 8.741 BBL/day = 14.02 scf/day = 0.010 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.232 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.006 scf/min
Emissions from water tank		0.010 scf/min
Emissions from pneumatic controllers		0.080 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.232 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.080 scf/min
Emissions from combustor connected to hydrocarbon tank		Methane included in tanks estimate
Total	0.328 scf/min	
Percentage of gas produced	0.21%	

Production Site Rocky Mountains 9 Data Report

Well information
Company: B

Surface Equipment Configuration
4 wells connected to 1 separator, gas from separator goes to sales. There is no combustor, 1 tank, and 1 water tank.
Pneumatic Controllers: 0 intermittent, 0 High bleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from separator and valves.

Production rates:
Gas: 0.068 million scf/day (74.54% methane)
Oil: 8.8 bbl/day
Water: 4.6 bbl/day

Site age: 1.0 yr

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 48.36º, a gas that is 74.54% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 8.8 BBL/day = 507.8 scf/day = 0.353 scf/min

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 74.54% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 74.54% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.8 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 4.630 BBL/day = 7.27 scf/day = 0.005 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.019 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0.353 scf/min
Emissions from water tank		0.005 scf/min
Emissions from pneumatic controllers		0.000 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.019 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.000 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	0.377 scf/min	
Percentage of gas produced	0.8%	

Production Site Rocky Mountains 10 Data Report

Well information
Company: B

Surface Equipment Configuration
6 wells connected to 3 separators, gas from separators goes to sales. There is no combustor, and 4 tanks.
Pneumatic Controllers: 0 intermittent, 0 High bleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from separators.

Production rates:
Gas: 0.420 million scf/day (76.19% methane)
Oil: 70.0 bbl/day
Water: 3.0 bbl/day

Site age: 1.0 yr

Site emissions calculations
Pneumatic controllers:
0 pneumatics on site reported, however, 1 was measured.
Pneumatic leaks = 1 * (0.027) scfm methane = 0.027 scfm methane

Tanks:
Emissions vented from hydrocarbon liquid tank:
Solubility of methane in hydrocarbon liquids estimated based on separator conditions (98ºF, 170 psig), an API gravity of 47.89º, a gas that is 76.19% methane, and the Vasquez-Beggs correlation: 58 scf methane/BBL gas

58 scf/BBL * 70.0 BBL/day = 4061.2 scf/day = 2.820 scf/min

Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (98ºF, 170 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 76.19% methane

Separator pressure is 170 psig or 185 psia; $X_{methane}$ = 185/670,000 = 0.0003 mol fraction

If the gas in the separator is 76.19% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 1.9 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.6 scf methane per bbl of water.
1.6 scf/BBL * 2.955 BBL/day = 4.74 scf/day = 0.003 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.010 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		2.820 scf/min
Emissions from water tank		0.003 scf/min
Emissions from pneumatic controllers		0.027 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.010 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.027 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	2.861 scf/min	
Percentage of gas produced	1.0%	

Production Site Appalachian 1 Data Report

Well information
Company: C

Surface Equipment Configuration
6 wells connected to 6 separators, gas from separators goes to sales. There are 4 tanks, 1 open top tank, and 2 produced water tanks.
Pneumatic Controllers: 0 intermittent, 0 Hibleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from vent and regulator in separators.

Production rates:
Gas: 10.3 million scf/day (96.83% methane)
Oil: 0.0 bbl/day
Water: 86.0 bbl/day

Site age: 1.8 yr

Site emissions calculations
Pneumatic controllers:
0 pneumatics on site reported, however, 5 were measured.
Pneumatic leaks = 5 * (0.132) scf methane = 0.662 scfm methane

Tanks:
Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60.ºF, 419.00 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 96.83% methane

Separator pressure is 419.00 psig or 434 psia; $X_{methane}$ = 434/670,000 = 0.0006 mol fraction

If the gas in the separator is 96.83% methane, the mol fraction methane would be 0.0006. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 5.5 g mol of methane per bbl (0.0006* 8830 g mol). This is 4.8 scf methane per bbl of water.
4.8 scf/BBL * 86.000 BBL/day = 411.28 scf/day = 0.286 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.008 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0 scf/min
Emissions from water tank		0.286 scf/min
Emissions from pneumatic controllers		0.662 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.008 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.662 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	0.955 scf/min	
Percentage of gas produced	0.01%	

Production Site Appalachian 2 Data Report

Well information
Company: C

Surface Equipment Configuration
6 wells connected to 6 separators, gas from separators goes to sales. There are 6 produced water tanks.
Pneumatic Controllers: 0 intermittent, 0 Hibleed, 0 Low Bleed
Chemical injection pumps: 1
Additional measured fugitive releases: from vent and regulator in separator, and casing annulus in well head.

Production rates:
Gas: 2.1 million scf/day (97.58% methane)
Oil: 0.0 bbl/day
Water: 172.0 bbl/day

Site age: 9.4 yr

Site emissions calculations
Pneumatic controllers:
0 pneumatics on site reported, however 8 were measured.
Pneumatic leaks = 8 * (0.417) scf methane = 3.334 scfm methane

Chemical injection pumps:
1 chemical injection pumps on site none were measured; using the average emission rate 0.192 scfm methane
Chemical injection pumps leaks = 1 * (0.192) scf methane = 0.192 scfm methane

Tanks:
Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (61.00ºF, 149.00 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 97.58% methane

Separator pressure is 149.00 psig or 164 psia; $X_{methane}$ = 164/670,000 = 0.0002 mol fraction

If the gas in the separator is 97.58% methane, the mol fraction methane would be 0.0002. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 2.1 g mol of methane per bbl (0.0002* 8830 g mol). This is 1.8 scf methane per bbl of water. 1.8 scf/BBL * 172 BBL/day = 313. scf/day = 0.218 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.451 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0 scf/min
Emissions from water tank		0.218 scf/min
Emissions from pneumatic controllers		3.33 scf/min
Emissions from chemical injection pumps		0.192 scf/min
Emissions from directly measured sources	0.451 scf/min	
Emissions estimated based on emission factors (excluding tanks)		3.53 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	4.20 scf/min	
Percentage of gas produced	0.28%	

Production Site Appalachian 3 Data Report

Well information
Company: C

Surface Equipment Configuration
6 wells connected to 6 separators, gas from separators goes to sales. There are 2 sand separators, and 2 tanks.
Pneumatic Controllers: 0 intermittent, 0 Hibleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: valves and well heads.

Production rates:
Gas: 10.7 million scf/day (97.01% methane)
Oil: 0.0 bbl/day
Water: 510.8 bbl/day

Site age: 0.4 yr

Site emissions calculations
Pneumatic controllers:
0 pneumatics on site reported, however 2 were measured.
Pneumatic leaks = 2 * (0.137) scf methane = 0.275 scfm methane

Tanks:
Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60.ºF, 444.00 psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 97.01% methane

Separator pressure is 444.00 psig or 459 psia; $X_{methane}$ = 459/670,000 = 0.0007 mol fraction

If the gas in the separator is 97.01% methane, the mol fraction methane would be 0.0007. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 5.9 g mol of methane per bbl (0.0007* 8830 g mol). This is 5.1 scf methane per bbl of water. 5.1 scf/BBL * 511 BBL/day = 2590 scf/day = 1.80 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 2.82 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0 scf/min
Emissions from water tank		1.80 scf/min
Emissions from pneumatic controllers		0.275 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	2.82 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.275 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	4.90 scf/min	
Percentage of gas produced	0.066%	

Production Site Appalachian 4 Data Report

Well information
Company: C

Surface Equipment Configuration
5 wells connected to 5 separators, gas from separators goes to sales. There are 2 produced water tanks.
Pneumatic Controllers: 0 intermittent, 0 Hibleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: well heads and separator.

Production rates:
Gas: 7.2 million scf/day (97.01% methane)
Oil: 0.0 bbl/day
Water: 237.2 bbl/day

Site age: 0.8 yr

Site emissions calculations
Pneumatic controllers:
0 pneumatics on site reported, however 1 was measured.
Pneumatic leaks = 1 * (0.030) scf methane = 0.030 scfm methane

Tanks:
Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60.ºF, 405. psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 97.01% methane

Separator pressure is 405. psig or 420 psia; $X_{methane}$ = 420/670,000 = 0.0006 mol fraction

If the gas in the separator is 97.01% methane, the mol fraction methane would be 0.0006. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 5.4 g mol of methane per bbl (0.0006* 8830 g mol). This is 4.6 scf methane per bbl of water. 4.6 scf/BBL * 237. BBL/day = 1100. scf/day = 0.764 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.569 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0 scf/min
Emissions from water tank		0.764 scf/min
Emissions from pneumatic controllers		0.030 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.569 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.030 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	1.36 scf/min	
Percentage of gas produced	0.027%	

Production Site Appalachian 5 Data Report

Well information
Company: C

Surface Equipment Configuration
6 wells connected to 6 separators, gas from separators goes to sales. There are 4 sand separators, and 2 produced water tanks.
Pneumatic Controllers: 0 intermittent, 0 Hibleed, 0 Low Bleed
Chemical injection pumps: 0
Additional measured fugitive releases: from well heads.

Production rates:
Gas: 27.4 million scf/day (97.01% methane)
Oil: 0.0 bbl/day
Water: 32.4 bbl/day

Site age: 0.4 yr

Site emissions calculations
Pneumatic controllers:
0 pneumatics on site reported, however 1 was measured.
Pneumatic leaks = 1 * (0.019) scf methane = 0.019 scfm methane

Tanks:
Emissions vented from water tank:
Solubility of methane in water estimated based on a separator conditions (60.ºF, 405. psig), a Henry's law constant of 4600 MPa or 670,000 psia (pure water) and a gas that is 97.01% methane

Separator pressure is 405. psig or 420 psia; $X_{methane}$ = 420/670,000 = 0.0006 mol fraction

If the gas in the separator is 97.01% methane, the mol fraction methane would be 0.0006. Assuming 159 kg/bbl, there are 8830 mol water in a 42 gal barrel of water (159,000g/18g mol^{-1}), and 5.4 g mol of methane per bbl (0.0006* 8830 g mol). This is 4.6 scf methane per bbl of water. 4.6 scf/BBL * 32.4 BBL/day = 150. scf/day = 0.104 scf/min

Emission sources measured with direct measurements:
Additional measured fugitive releases: 0.270 scf/min

Source	*Measurement*	*Estimate*
Emissions from hydrocarbon liquid tank		0 scf/min
Emissions from water tank		0.104 scf/min
Emissions from pneumatic controllers		0.019 scf/min
Emissions from chemical injection pumps		0.000 scf/min
Emissions from directly measured sources	0.270 scf/min	
Emissions estimated based on emission factors (excluding tanks)		0.019 scf/min
Emissions from combustor connected to hydrocarbon tank		0
Total	0.393 scf/min	
Percentage of gas produced	0.002%	

Appendix K

Direct Source Measurements: Gas Well Workovers

Background on Gas Well Workovers

After a well is drilled and after it is placed into continuous production, natural gas production declines over time as the reservoir is depleted, or as the well down-hole equipment ages or becomes compromised. Remedial maintenance performed on the well to restore or maintain production may be considered a workover. This term applies to the well's down-hole equipment, not to other surface equipment such as separators and tanks. Down-hole equipment includes the drilled well opening or wellbore, the various levels of casing and cementing, the annular tubing (production string), and any other down-hole devices such as perforations, plugs, electric submersible pumps, or other equipment.

Workover service to a well is different than service on surface equipment such as separators, compressors, and tanks, simply because access inside the wellbore is technically complicated, and requires unique equipment. A broad variety of downhole service operations may be considered to be well workovers. These include, but are not limited to, replacing tubing, recompleting to a different zone, acidizing near wellbore damage, plugging, and abandoning.

Defining the precise scope of workover activities is challenging. Some organizations define some types of downhole service operations as "well servicing" rather than as a well workover. This term is sometimes but not universally used where an operation is performed through the wellhead "Christmas tree" with the production string still in place. Small diameter tubing, coiled tubing, wireline, and snubbing equipment can be used in those cases. These operations are similar to workovers in scope, they occur inside the production tubing, and they may or may not require the production tubing to be open to the atmosphere. However, other organizations may define a workover as any post-completion service to the well, while others limit the definition of "workover" to certain operations, such as those requiring a workover rig on site (Figure K-1), or those requiring removal of the wellhead "Christmas tree" piping at the well (Figure K-2), leaving the well open to the atmosphere (after the well is hydraulically loaded to prevent emissions).

Increasing the complexity of defining the meaning of the term "workover" are a variety of regulatory definitions. EPA has proposed a definition of well workover in the GHG Mandatory Reporting Rule in 40 CFR 98.6 (CFR 2010) as follows:

> ***Well workover*** means the process(es) of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

This definition suggests that EPA limits workovers to processes involving flowbacks. In addition, the Offshore MMS Definitions (30 CFR 250.601), specify that certain routine operations are *not* workovers:

Routine operations mean any of the following operations conducted on a well with the tree installed:

(a) Cutting paraffin;
(b) Removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations;
(c) Bailing sand;
(d) Pressure surveys;
(e) Swabbing;
(f) Scale or corrosion treatment;
(g) Caliper and gauge surveys;
(h) Corrosion inhibitor treatment;
(i) Removing or replacing subsurface pumps;
(j) Through-tubing logging (diagnostics);
(k) Wireline fishing; and
(l) Setting and retrieving other subsurface flow-control devices.

Workover operations mean the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 71 FR 11313, Mar. 7, 2006]

Thus, the precise definition of a workover, varies in regulation and in individual company usage. Most of the definitions of workovers include activities with liquid flowback, similar to a well completion, however, many other types of events could be included.

Because the Study team was visiting production regions with high drilling activity and consequently relatively young wells not requiring workovers, the opportunities for sampling workovers were limited. Four events were sampled, and these are listed in Table K-1. Three of these were swabbing events with liquids sent to a horizontal cylindrical tank. Swabbing is included in some definitions of workovers but not in others (30 CFR 250.601, Offshore MMS Definitions). During a swabbing, a swab cup is run on the end of a wireline inside the tubing of a well to a depth below the top of the liquid column in the tubing. As the wireline is pulled out of the well, the liquid is pulled to the surface by the swab cup. Downhole liquids are brought up and into surface tankage (bypassing the separator), so flashed gas can escape through tank vent. Measurements were made from the tank vent for these events. A fourth workover event was a recompletion that involved flow to a vented tank followed by flow to a separator with gases flared.

Figure K-1. Workover Rig

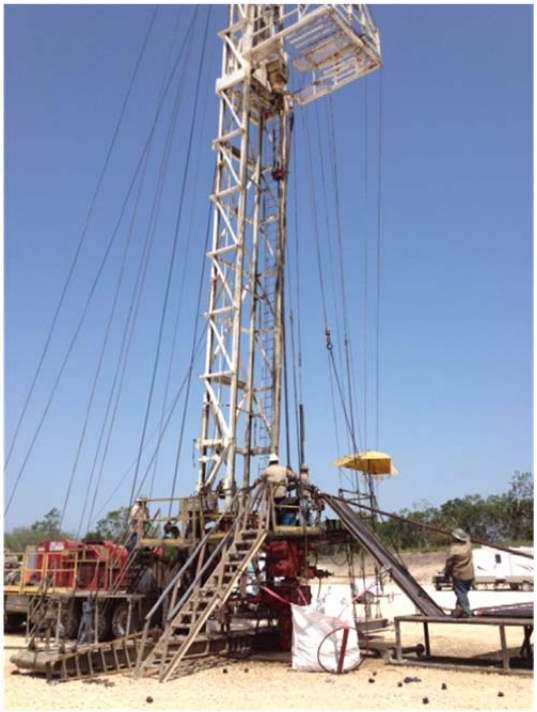


Figure K-2. Gas Wellhead "Christmas Trees"

Table K-1. Workovers sampled

Event number	Description
1	Swabbing; Liquid sent to vented horizontal tank; emissions measured from hatch on tank.
2	Swabbing; Liquid sent to vented horizontal tank; emissions measured from hatch on tank.
3	Swabbing; Liquid sent to vented horizontal tank; emissions measured from hatch on tank.
4	Recompletion workover, configured in a manner similar to a completion

Methods

The method used to measure emissions from the swabbing events is identical to the method used to measure emissions from flowback tanks, described in the main study reports (Allen, et al., 2013). Flow is directed through a portable stack installed on top of the tank vent that the liquids from the swabbing are directed to. Flow rate through the temporary stack was measured continuously, near the centerline of the temporary stack, using a pitot tube. Total volumetric flow was calculated by multiplying the stack cross-sectional area by 80% of the gas velocity at the stack centerline. The factor of 0.8 was used to convert the centerline velocity in the stack to an estimated average velocity in the stack (see Appendix C). Gas samples for composition analysis were drawn through tubing to a sampling port 10-20 meters from the tank. Gas samples were drawn into evacuated tedlar bags for subsequent analysis using gas chromatography. Details of the chromatographic analysis method are available in Appendix B.

For the recompletion workover, methods were identical to those described in Allen, et al. (20130 for well completion events.

Results and Discussion

Data on workover emissions are reported in Table K-2. Average emissions for the three swabbing events were 2800 scf methane. Emissions from the recompletion were estimated at 20,000 scf methane, largely due to estimated methane emissions from flaring.

Table K-2. Methane emissions from Workovers

Event number	Description (duration, hr)	Methane emissions (scf)	Emissions estimation method
1	Swabbing	5300[1] (4200)[2]	26,300 scf of gas flow (based on centerline gas velocity in temporary stack) with 20 mol% methane yields 5300 scf. Assuming average velocity is 80% of centerline velocity yields an estimate of 4200 scf
2	Swabbing	3040[1] (2400)[2]	19,000 scf of gas flow (based on centerline gas velocity in temporary stack) with 16 mol% methane yields 3040 scf. Assuming average velocity is 80% of centerline velocity yields an estimate of 2400 scf
3	Swabbing	2160[1] (1730)[2]	9,000 scf of gas flow (based on centerline gas velocity in temporary stack) with 24 mol% methane yields 2160 scf. Assuming average velocity is 80% of centerline velocity yields an estimate of 1730 scf
4	Recompletion	20,000[3]	Sampling configuration similar to that for Configuration 1 in Table S1-1 (Supporting Information, Allen, et al., 2013); emissions includes initial flow to vented tank (9030 scf total gas vented with an average of 6.5% methane); emissions estimate, however, is dominated by flared gases: 948,000 scf of gas at 81% methane, with a 98% combustion efficiency is 15,000 scf methane

[1]based on temporary stack cross sectional area * centerline velocity
[2]based on temporary stack cross sectional area * centerline velocity * 0.8 (see Appendix C)
[3]flow from open top tank was estimated at 9030 scf at 6.5% methane (<1,000 scf methane); methane from flare was estimated as 15,000 scf

Summary

The data set reported here is very small, in part because the Study team was visiting production regions with high drilling activity and consequently relatively young wells not requiring workovers. Nevertheless, the emissions per event can be compared to average emissions for workover events in the national greenhouse gas emission inventory of 4.2 million scf/event for events involving hydraulic fracturing and 2570 scf/event for events without hydraulic fracturing (U.S. EPA, 2013). The average swabbing event emissions (2800 scf/event) are comparable to the workover estimates for workovers without hydraulic fracturing (2570 scf/event). The total gas generated during the recompletion workover (event 4) was approximately 1,000,000 scf of total gas. This well workover did not involve hydraulic fracturing, however, the potential emissions from the flowback are of the same order of magnitude as the EPA estimated value of 4.2 million scf for workovers with hydraulic fracturing. Because approximately 99% of the total gas flow was flared, the estimated emissions for the recompletion are only about 2% of the potential emissions.

Allen, D.T., Torres, V.M., Thomas, J., Sullivan, D., Harrison, M., Hendler, A., Herndon, S.C., Kolb, C.E., Fraser, M., Hill, A.D., Lamb, B.K., Miskimins, J., Sawyer, R.F., and Seinfeld, J.H. Measurements of Methane Emissions at Natural Gas Production Sites in the United States, *Proceedings of the National Academy of Sciences* (2013).

U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011.* EPA 430-R-13-001, April 2013.