Supplemental Material

Equipment leak detection and quantification at 67 oil and gas sites in the Western United States

Adam P. Pacsi[1,*], Tom Ferrara[2], Kailin Schwan [2], Paul Tupper[3], Miriam Lev-On[4], Reid Smith[5] and Karin Ritter[6]

[1]Chevron Energy Technology Company, Houston, Texas, USA

[2]GHD Services Incorporated, Niagara Falls, New York, USA

[3]Shell Global Solutions (US) Inc., Houston, Texas, USA

[4]The LEVON Group, LLC, Thousand Oaks, CA, USA

[5]Earth Systems Sciences LLC, Houston, Texas, USA

[6]American Petroleum Institute, Washington, District of Columbia, USA

*Corresponding author: Adam Pacsi adam.pacsi@chevron.com

Contents

Section S1. Additional materials and methods information

Basin Selection

For this study, four basins were selected for field sampling: Permian, Anadarko, San Juan, and Gulf Coast basins. As shown in Figure S1, these represent the four basins with the largest reported methane emissions from equipment leaks in 2016 under the US Greenhouse Gas Reporting Program (GHGRP) for the production and gathering and boosting segments. The 2016 comparison year was selected for Figure S1 since it was the first year where emissions, including equipment leak emissions, were reported for the gathering and boosting segment under the GHGRP.

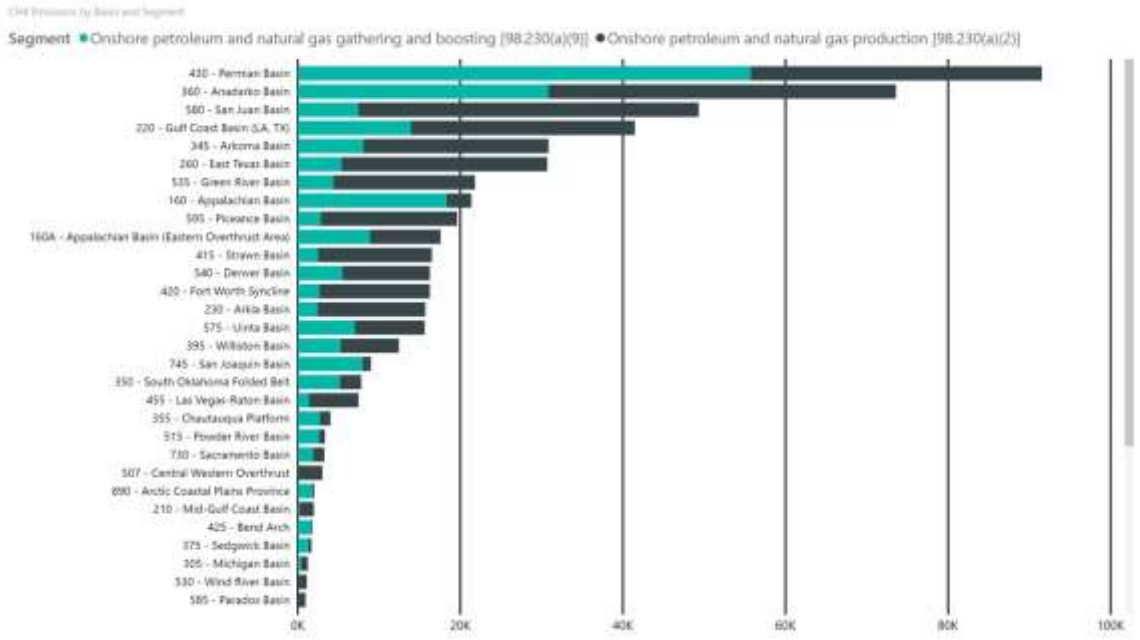

Figure S1. Total reported methane emissions from equipment leaks by basin in 2016. Emissions reported by operators in the production and gathering and boosting segments to the US EPA in 2016 under the GHGRP, grouped by reporting basin. Typically, emissions reported in the production and gathering and boosting segments in the GHGRP are estimated based on a count of major pieces of equipment on the site combined with default component counts per piece of major equipment and default emission factors per component.

Site Selection

Potential sites for the study were provided by eight companies operating in the four target basins. Individual sites selected for the study were representative of the facility and equipment types for the operator in each of the study basins. The site selection process included:

- Classification of the sites into four categories based on the equipment present at each facility (Table S1).
- Random selection of target sites within the assets of each operator in a basin (Table S2).
- Sites were clustered geographically within the basin to minimize drive time.
- Extra sites were chosen for each operator in the event a site was unavailable or additional sites could be visited.

Table S1. Site classification for facilities in this study. Classification of the 67 sites in this study based on the type of major equipment present. The use of an X indicates that the type of equipment was present for that category of site.

	Facility Category for This Study			
Major Equipment Type	**Well Site**	**Well Production**	**Central Production**	**Gathering and Boosting**
Wellhead	X	X	X	
Separator	X	X	X	X
Heater Treater	X	X	X	
Compression	X	X	X	X
Dehydration		X	X	X
Treatment			X	X
Other				X

Table S2. Details on basin and classification of sites in the study. Table includes count of sites by oil/gas, basin, and study classification.

Site Classification	Count of Gas Sites				Count of Oil Sites			
	San Juan	Gulf Coast	Anadarko	Permian	San Juan	Gulf Coast	Anadarko	Permian
Well Production	2	3	12	0	0	0	1	3
Central Production	1	4	0	0	2	0	0	2
Well Site	4	3	5	0	2	2	3	8
Boosting and Gathering	1	2	5	0	0	2	0	0
Total	**8**	**12**	**22**	**0**	**4**	**4**	**4**	**13**

The 67 sites included in this study included 20 back-up sites selected. Of these 20 sites, 12 sites were opportunistically selected nearby sites that were measured after the leak detection and quantification were completed at the original 5 sites for each operator. Eight sites were unavailable to the study team due to issues such as shut in wells, compressor maintenance, and sites where all piping was overhead and would have required an aerial lift for screening and measuring leaks.

Major Equipment Inventory

An inventory of the major equipment was completed at each facility. The types of equipment were used to classify the site into each of the four site categories. The major equipment lists provided in tables W-1B and W-1C of 40 CFR 98 Subpart W (Subpart W) were used wherever possible for describing equipment at each facility (Table S3).

Subpart W does not include a clear definition of separators. As a result, this study assumes that separators are process equipment that remove the bulk of the liquids from the well stream prior to further processing. Minor separators are defined in this study as smaller separators that handle minor amounts of liquids, such as fuel scrubbers, instrument gas separators, and compressor inlet and mid stage scrubbers. Minor separators are not used in site equipment counts for purposes of emission estimation and comparison to EPA methods since they would be unlikely to be counted for Subpart W reporting but components associated with minor separators are included in the development of site-level component counts (i.e. number of valves, etc.).

Table S3. List of major equipment types used throughout this study.

Natural Gas Sites	Crude Oil Sites
Wellhead	Wellhead
Separator	Separator
Meters/Piping	Heater Treater
Compressor	Header
Inline Heater	
Dehydrator	

Component Counts

The number of components at each site was determined by counting all the process components in liquid or gaseous service associated with each piece of major equipment. Components were classified as valves, connectors, pump seals, etc. in alignment with Subpart W categories outline in 40 CFR 98 Subpart W Table W-1B.

Leak Screening

Leak screening of all components at each facility handling hydrocarbon gas was completed by two GHD crew members, one conducting Reference Method 21 (RM-21) screening using a Thermo TVA-1000B flame ionization detector (FID) and one conducting optical gas imaging (OGI) screening using a FLIR GF-320 infrared camera, working independently. By working independently, sampling bias between the two techniques was limited. Operationally, the OGI screener started screening while the RM-21 screener was calibrating the instrumentation.

Optical Gas Imaging

OGI devices, such as the FLIR GF-320, are capable of detecting hydrocarbon emissions by imaging gases that absorb in the 3.2-3.4 μm Mid-Wave Infrared (MWIR) range. The OGI technique has been recognized by the US EPA as a method for identifying fugitive emissions from process components as an alternative to Method 21 for New Source Performance Standards (NSPS) Leak Detection and Repair (LDAR) regulations (40 CFR §60.18(h)(7)).

The FLIR GF-320 IR camera does not require a daily calibration adjustment. This instrument is equipped with an internal 'power on' self-test calibration that occurs as the instrument is energized and warmed-up. Prior to each use, the OGI device was checked for proper operation, and the instrument's sensitivity to methane gas was confirmed.

After daily operational checks and orientation at the site, the OGI operator systematically traced each pipe run and component at the facility scanning for leaks. Once a leak was identified, it was

given a unique identification number, but not tagged until completion of the RM-21 survey in that area of the facility.

An evaluation of the sensitivity demonstration consists of a controlled release of 100 % methane at two mass rates: 6 and 60 grams methane per hour, with a video recording made of each result. The distance from which the OGI device operator was able to see the test plume of the controlled release (i.e., the sighting distance) was recorded for each mass flow rate together with ambient temperature, wind speed, relative humidity, barometric pressure, cloud cover, and ambient lighting conditions.

RM-21 Methods and Procedures

Reference Method 21 (RM-21) - Determination of Volatile Organic Compound Leaks, is a leak detection method that is described in 40 CFR 60 Appendix A for determining leaks from process equipment. The GHD field team used a Thermo TVA-1000B (TVA) flame ionization detector (FID) calibrated with methane. During RM-21 screening the operator placed the TVA probe along the areas of a component where leaks were possible. The probe was slowly moved along the sealing surfaces while the operator watched the instrument concentration display. If the reading was greater than 500 ppm, the component was tagged by the operator for subsequent emission rate measurement. The date, time, operator name and screening concentration were recorded for each leak. Screening concentrations greater than 50,000 ppmv generally caused the TVA to 'flame-out', and for these instances, the screening value was recorded as 50,000 ppmv in the study data set.

The TVA was performance-tested (response time, precision, flow rate) at the start of the measurement program and was calibrated daily prior to field use at three concentration levels using ambient air, 500 ppmv methane-in-air , and 10,000 ppmv methane-in-air. The calibration gases had a certified accuracy of ± 2%. Drift checks were performed using the 500 ppmv and 10,000 ppmv standards at mid-day and at end of the day with a 10% acceptance criteria for recalibration.

Emission rate measurements

Natural gas emission rates were determined using a technique known as high-volume sampling that was first described in Indaco Air Quality Services, Inc., 1995 and referred to by the USEPA as the "high volume sampler" in 40 CFR 98.233 (k). This technique uses an instrument that consists of a vacuum pump operating at a sample flow rate of between six and ten SCFM, a flow rate sensor, and a dual range combustible gas sensor. The combustible gas sensor is comprised of

a catalytic oxidation detector for gas concentrations between 0 and 5% gas and a thermal conductivity detector for gas concentrations from 5 to 100% gas. The method involves using the vacuum sampler to collect the gas emitted from a release point and ambient air surrounding the leak into the sampler. The leak rate is calculated from the sample flow rate and the concentration of combustible gas in the sample using the following calculation:

$$Q_{Raw} = F_{Sample} \times (C_{Sample} - C_{Background})$$

Where:

Q_{Raw} = uncorrected emission rate of combustible gas from the leak (SCFM)

F_{Sample} = sample flow rate (SCFM)

C_{Sample} = concentration of combustible gas in the sample (% gas)

$C_{Background}$ = concentration of combustible gas in the background (% gas)

The background gas concentration is subtracted from the sample concentration to account for other sources near the source being measured.

For this study, a Hi Flow® Sampler manufactured by Bacharach Inc. was used to as the primary equipment to quantify emissions from component leaks. An additional high volume sampler, the Indaco sampler, was used as a backup to the Bacharach high-volume sampler in cases where the Bacharach could not be used due to maintenance or time-constraints. The sampler used for each component measurement are shown in the supporting database for the study. The sensors used by the high-volume samplers respond to CH_4 and have a range of responses to C_2 through C_4 compounds. The sensors of the Bacharach Hi Flow ® sampler have higher responses for the heavier hydrocarbons and non-hydrocarbons that may be present in field natural gas. Thus, the raw high volume sampler responses need to be adjusted to reflect the composition of the gas being measured to report the results as a whole gas emission rate.

A series of response factors (RF), based on mole-percent, were developed for the high-volume samplers (Bacharach and Indaco) and secondary detectors used in this fieldwork by metering known volumes of gas to the detection equipment as shown in Figure S2 and S3. An Alicat Mass Flow Controller (Alicat Scientific, Inc.) Model MCR-50SLPM-D was used to meter a range of volumetric flow rates of methane, ethane, propane, and butane to each detection instrument used in this study. Alicat Flow Controllers provide gas flows corrected to standard temperature and pressure (20°C and 1 atm.) and are equipped with an internal gas program that allows the operator to adjust the flow controller for the gas being metered. The Alicat MCR serial number 177760 was calibrated in the range of 0-40 SLPM by Alicat Scientific on May 30, 2018. Prior to

response testing, gas detection equipment was calibrated according to the manufacturer's specifications. The specific hydrocarbon was selected on the Alicat Flow Controller for each metered gas prior to testing. The connection line from the flow controller to the detection equipment was purged between each test set. The response factor is the ratio of the instrument response to a controlled release of a pure gas to the true value of the metered gas.

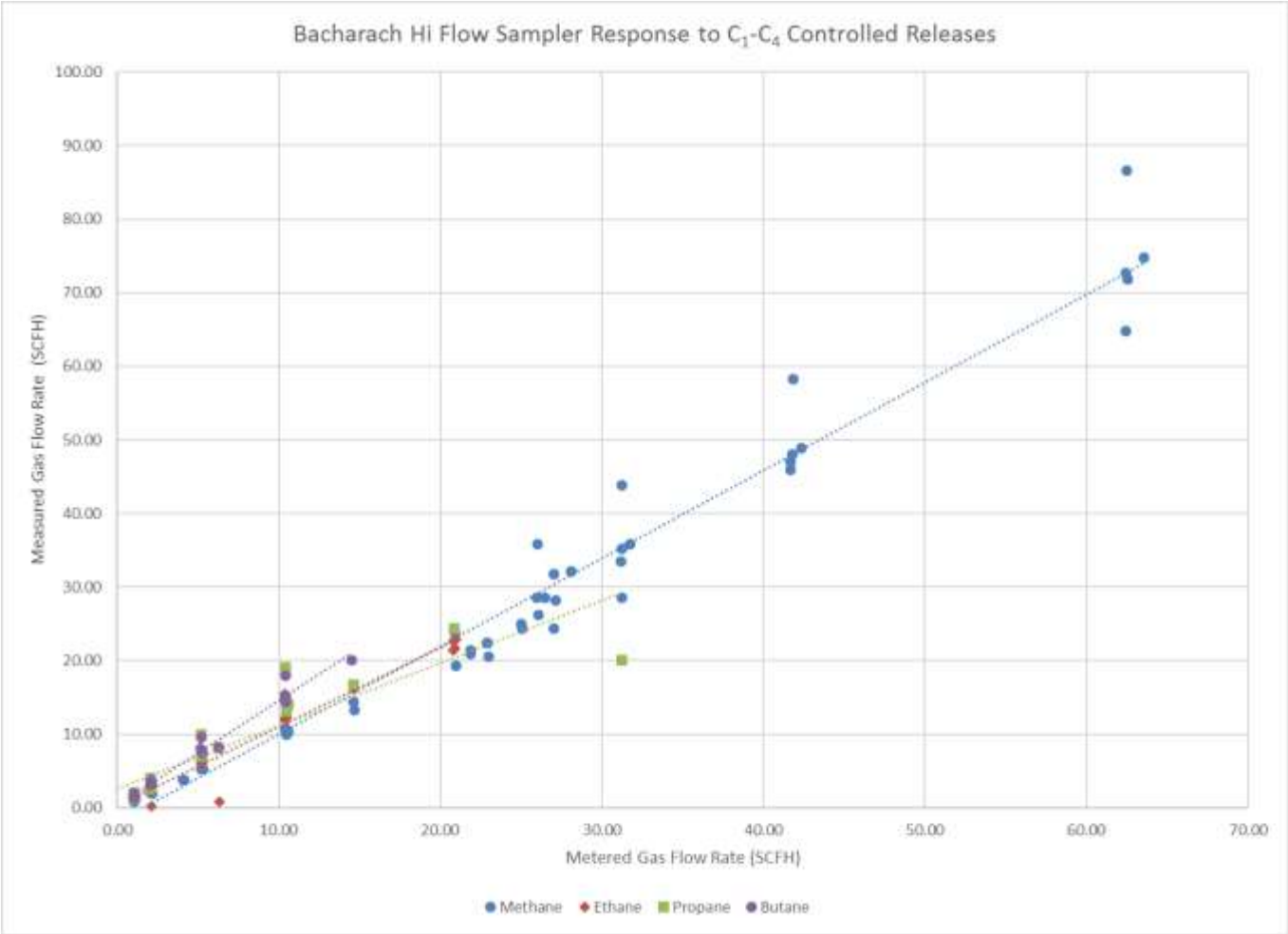

Figure S2. C1-C4 Instrument Responses for the Bacharach High Volume Sampler. Instrument responses were determined for each of the primary constituents found in natural gas, for each sampler used in this study.

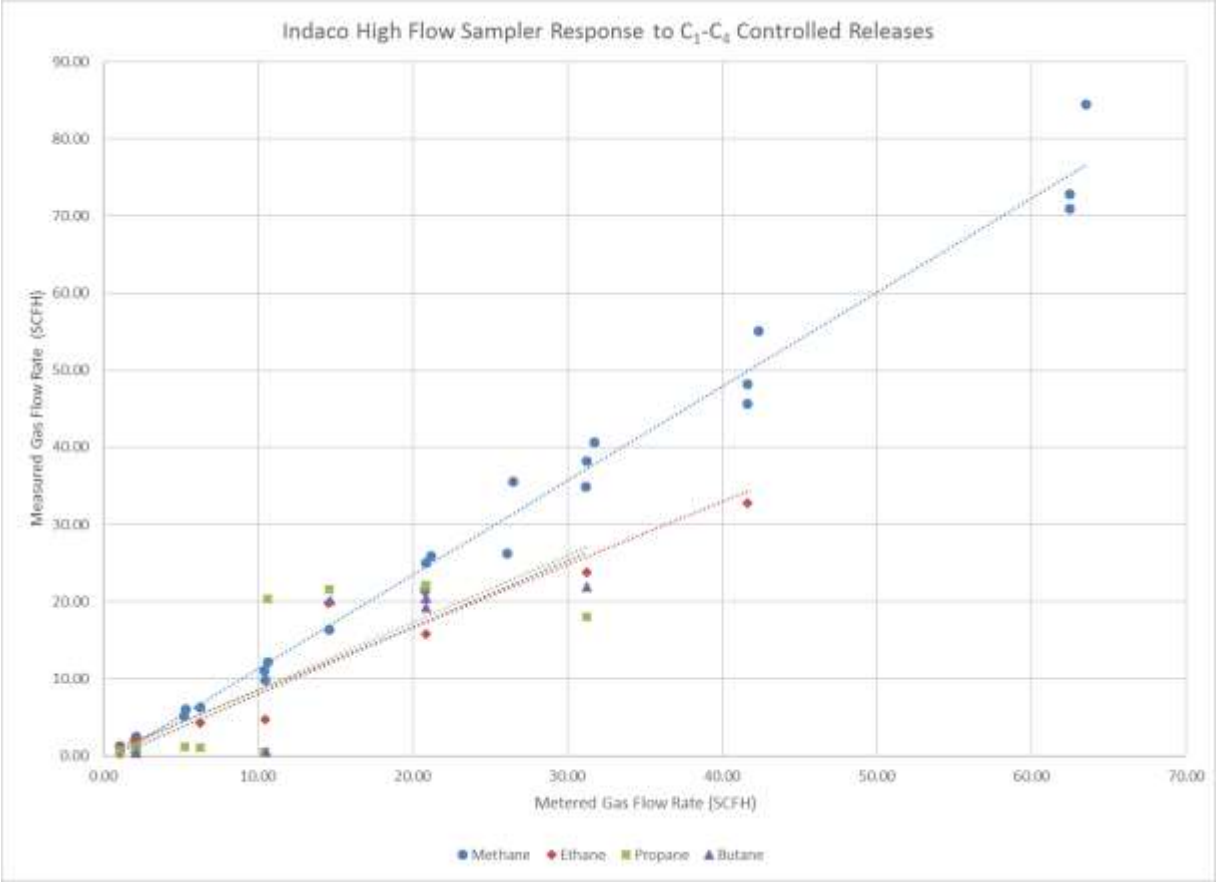

Figure S3. C1-C4 Instrument Responses for the Indaco High Volume Sampler. Instrument responses were determined for each of the primary constituents found in natural gas, for each sampler used in this study.

An instrument response model was developed for each sampler based on each site's gas composition and laboratory testing for the RF factors (as shown in Table S5), as follows:

$$RF_{Site} = \left(\%CH_4 \times RF_{CH_4}\right) + \left(\%C_2H_6 \times RF_{C_2H_4}\right) + \left(\%C_3H_8 \times RF_{C_3H_8}\right) + \left(\%C_4H_{10} \times RF_{C_4H_{10}}\right)$$

The whole gas emission rates were calculated by adjusting the measured emission rate by the site-specific response factor as follows:

$$Q_{Whole\ Gas} = \frac{Q_{Raw}}{RF_{Site}}$$

Gas composition data for 57 out of the 67 sites surveyed was provided by the host companies. For the ten sites where data was not available the average gas composition from similar sites within the same basin were substituted.

Augmented high-volume sampler quality assurance procedure

There have been documented instances when the Bacharach Hi Flow® Sampler quantification results were biased low (Brantley, et al., 2015, Howard et al., 2014 and Modrak et al., 2012) due to failure of the device to transition between detector ranges. Brantley reported that significant negative bias occurred when the sample stream had greater than 10% non-methane hydrocarbons (<90% CH_4 in the site gas composition). For this reason, the Hi Flow® Sampler used on this project was equipped with a backup hydrocarbon sensor at the Hi Flow® sampler exhaust to provide real time quality assurance of the gas concentration measurement. These past studies have shown that the Hi Flow® Sampler can experience issues in the transition region (~5% gas) and displays an unstable reading fluctuating between 2% and 4% gas.

In those instances where the Hi Flow® high-volume sampler and the secondary detector did not agree, and the Hi Flow® Sampler concentration was within 2% to 4% hydrocarbon measurement range, the higher measurement from the secondary detector was used in the emission calculation that is shown as Q_{Raw} in the previous section. There were six instances in this field program where the Hi Flow® Sampler failed to transition between the low range (0-5% gas) and the high range (> 5% gas). In these six cases, the concentration data taken from the backup detector, which in these cases was the DPIR, was used to calculate the component leak rates.

In addition to using the backup detectors for providing data during transition failures, the backup instruments had lower detection limits than the Hi Flow® Sampler. The Bascom-Turner Gas Rover was one of the instruments used as a secondary detector and has a minimum gas detection limit below that of the Hi Flow® Sampler. In those instances when the Hi Flow® Sampler reading was non-detect (ND), the gas concentration reading from the Gas Rover was used in the emission rate calculation. This situation occurred for leaks at the lower end of the leak distribution. The DPIR was not used for replacing Hi Flow® Sampler ND reading due to the elevated response for the DPIR to hydrocarbons above C1 in laboratory testing. In these cases, the Hi Flow® Sampler detection limit value was reported. Table S4 provides a total for how often each sampler/detector combination was used throughout the study.

Table S4.: Summary of detection equipment used in final emissions calculations. Row with X indicates the number of times that a backup instrument was used in final emission rate quantification for a leak in this study.

High Volume Sampler	Gas Detection Instrument Used for Concentration Reading	Backup Gas Instrument	No. of Leaks in Study where used for concentration reading
Bacharach	Bacharach Cat Ox/TCD		213
Bacharach	Heath DPIR IR	X	6
Bacharach	Bascom-Turner Gas Rover Cat Ox/TCD	X	73
Bacharach	Bascom-Turner Gas Sentry Cat Ox/TCD	X	0
Indaco HF	Bascom-Turner Gas Rover Cat Ox/TCD		39

The high-volume sampler was calibrated daily, or more frequently, if a single point mid-day check of the previous calibration was outside the ±10% acceptability range. The high-volume sampler was calibrated using the vendor-supplied calibration kit and demand regulators to ensure consistent flow rates. Gas standards for the calibration included zero-air (rather than background air), a 2.5% methane standard for the low threshold sensor, and a 100% methane standard for the high threshold sensor. The full calibration procedure followed the guidance provided in Section 3.0 of the Bacharach Hi Flow® Sampler Operations & Maintenance Manual (Bacharach, 2015). Flow sensors were verified weekly using a calibrated rotameter connected to the sample line. All periodic flow calibration checks were within ± 8 % of the accepted value and averaged 4%, which includes the uncertainty in the rotameter calibration.

Additional quality assurance measures

The high-volume samplers have combustible gas detectors that utilize both catalytic oxidation (Cat Ox) and thermal conductivity (TCD) sensors. The catalytic oxidation sensor is used in the range of 0% to 5% gas and the TCD in the range >5% to 100%. The Hi Flow® Sampler uses differential pressure across an orifice plate to measure flow rate. The Indaco high-volume sampler uses a TSI® hot-wire hotwire anemometer to measure sample gas flow rate.

The high-volume instrument's hydrocarbon sensors were calibrated at 2.5% and 100% methane. These points represent the span of the TCD sensor (Gas concentrations > 5 %) and the midpoint of the catalytic oxidation sensor (Gas concentrations between 0 and 5 %). Before conducting field measurements, the high-volume samplers were challenged with a range of methane volumetric flow rates to verify the linearity of the instrument. The linearity of each sensor was documented and is shown in Figures S2 and S3.

Separate response factors and linearity checks (Figure S3 for the Indaco high flow sampler) were developed for each of the backup instruments as shown in Table S5 and used in the emission rate calculations in this work.

Table S5. Response factors determined for each instrument used in the study. Due to the large uncertainty of the Heath DPIR's response in previous testing to higher hydrocarbons, a Heath DPIR response factor was developed based on the gas compositions of the leaks where the Heath DPIR was used. Artificial mixtures of gases representing the composition of the field gas where the DPIR was prepared in a Tedlar bag. Dilutions of this gas were supplied to the Heath DPIR and a response factor was developed and applied to the six measurements where the DPIR was used.

	Observed Response Factor			
Equipment	C_1	C_2	C_3	C_4
Bacharach HF				
(0.5%≥ x ≤5%)	1.02	1.24	1.40	1.53
(x ≥5%)	1.09	1.24	1.40	1.53
Indaco HF	1.13	0.79	0.60	0.70
BT Gas Rover	1.04	1.11	0.46	1.38
BT Gas Sentry	1.01	0.86	1.02	2.95
Heath DPIR	4.48			

Section S2. Details on Emissions from Glycol Pump

When arriving at one of the field sites, the GHD technicians and company representatives on-site immediately heard a hissing sound that is associated with the release of high pressure gas. Upon investigating the sound, the personal lower explosion limit (LEL) detectors for the GHD field team alarmed, and the field team also noted a strong hydrocarbon odor.

The operations personnel from the host company conducted an audio, visual, olfactory (AVO) survey of the site and located the source, which was a cracked fitting on a glycol pump discharge for a dehydration system on the wet (rich) side of the unit. The problem was apparent to the operator through visible signs (i.e. the ice in Figure S4). A maintenance crew was called and when they arrived, the pump was immediately removed from service by re-routing flow to the on-site spare pump. A root cause analysis was undertaken on the site and through follow-up discussions through Kimray, which is the vendor of the equipment.

Due to safety reasons, the equipment near this dehydrator was not surveyed.

The vendor (Kimray) indicated that this type of crack would cause the emissions to be primarily hydrocarbon in gas content versus the typical mixture (1/3 site natural gas, 2/3 glycol) that would be in the wet-side discharge from the pump. The emissions from the pump also had a clear temporal pattern that corresponded to the stroking of the pump. This allowed for maximum emissions to be estimated based on the system volumes and the frequency of pumping strokes. However, it is not known what percentage of this maximum gas volume escaped since quantification measurements would have been unsafe and likely unable to accurately characterize the release volume.

Figure S4. Photograph of the wet glycol discharge piping where the emission source was identified. The equipment was determined to be a Kimray 21020 PV model glycol pump. The maximum emission rate from the event was determined through interaction with the pump manufacturer and parameters recorded on-site.

The upper bound of emissions from this glycol pump was calculated based on the manufacturer specification sheet for the equipment (Kimray, 2013) and data collected while the GHD field team was on-site. This included a cellular phone video of the pump strokes that allowed for a counting of the number of strokes per minute for the pump in operations. The upper bound emission calculation presented below assumes that the entire internal volume of the wet side of the pump is emitted (30 cubic inches) during each of the 32 strokes per minute for the pump that were counted from the video, and results in an emission estimate of 2,074 scfh.

$$System\ Volume\ (scf) = \frac{(30\ in^3)\left(\frac{900+14.69\ psi}{14.69\ psi}\right)}{1728\ in^3/ft^3} = 1.08\ scf$$

$$Upper\ bound\ emission\ rate\ (scfh) = \left(\frac{1.08\ scf}{stroke}\right)\left(\frac{32\ strokes}{minute}\right)\left(\frac{60\ minute}{hour}\right) = 2074\ scfh$$

Given the uncertainty around the composition of the gas release, it is not feasible to adequately characterize the methane emissions or hydrocarbon content of the gas leak. Since the emission source could not be safely screening with an FID or infrared camera and since the site observations (personal LEL alarms, hydrocarbon odor, and human-eye visible emissions) immediately drew the attention of the GHD field team and company operations representatives, this emission is not included in the development of equipment leak emission factors for this study. In the opinion of the GHD field team, any trained operator that arrived on site would have immediately identified the emission source and mitigated the emissions, so it would not have required an instrumented LDAR survey for identification.

Section S3. Additional results and discussions

Table S6. Count and emission of leaking components identified in leak detection surveys in this study. Leaking components were identified by optical gas imaging (OGI) and/or flame ionization detectors (FID) surveys at 67 oil and gas sites in the US.

Component Type	Count of Leaking Components	Percent of Leaking Components	Emissions from Leaking Components (scfh)	Percent of Emissions from Leaking Components (scfh)
Connectors	187	57%	500.9	35%
OELs	16	5%	135.7	9%
Valves	54	16%	317.0	22%
Flange	17	5%	233.0	16%
Instrument	10	3%	42.7	3%
Regulator	24	7%	107.6	8%
Vent	2	1%	42.3	3%
Other	16	5%	42.1	3%
Piping	1	0%	15.5	1%
PRVs	3	1%	3.4	0.2%
Pump	1	0%	0.2	0.02%
Total	331	100%	1440.7	100%

Table S7. Summary statistics for leaking components identified in oil, gas, and both services. Leaking components were identified by optical gas imaging (OGI) and/or flame ionization detectors (FID). Counts are shown for all 67 sites in the study and for the 65 sites in the study with a component count.

	Oil and Gas Service	Gas Service	Oil Service
Count at 67 Sites	331	307	24
Count at 65 Sites with a component count	326	302	24
Minimum (scfh)	0.006	0.006	0.026
Maximum (scfh)	83.7	83.7	27.4
Average (scfh)	4.35	4.42	3.50
Median (scfh)	0.34	0.34	0.30

Table S8. Summary Statistics for leaking components identified by OGI and FID-based survey methods. Leaking components were identified by optical gas imaging (OGI) and/or flame ionization detectors (FID) surveys at oil and gas sites in the US. At two sites, an OGI survey was undertaken but an FID-based survey was not undertaken. Thus, OGI results are presented both including and excluding those two sites.

	Detected with OGI	Detected with FID	Detected with OGI, FID survey also occurred
Count at 67 Sites	113	293	106
Count at 65 Sites with a component count	111	290	104
Minimum (scfh)	0.011	0.006	0.011
Maximum (scfh)	83.7	75.9	83.7
Average (scfh)	10.33	3.68	10.36
Median (scfh)	2.80	0.31	2.73

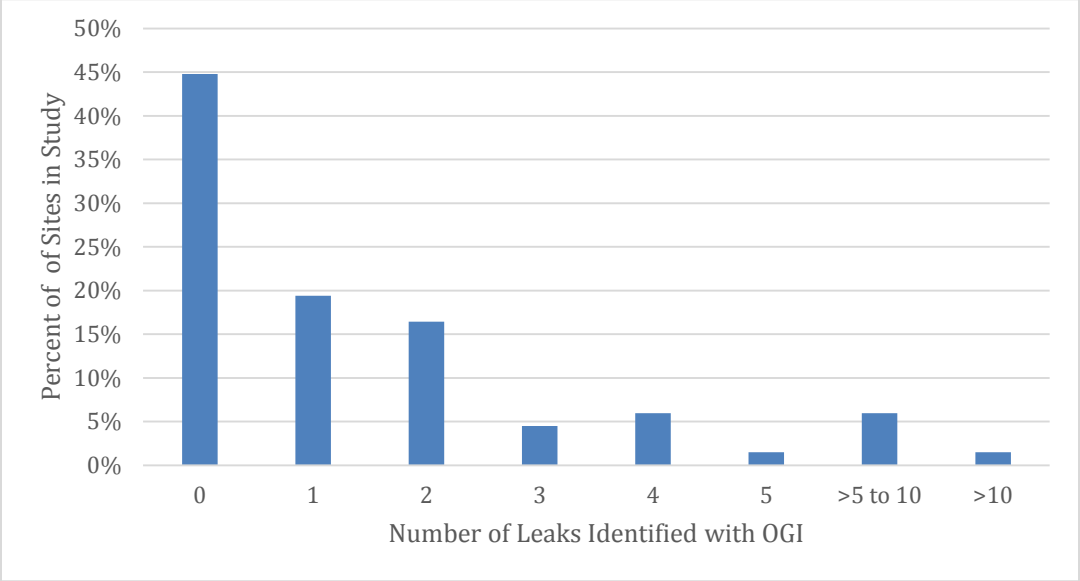

Figure S5. Distribution of number of leaks identified by OGI per site. Figure displays the count of sites in the study binned by the number of leaks detected at that site by OGI.

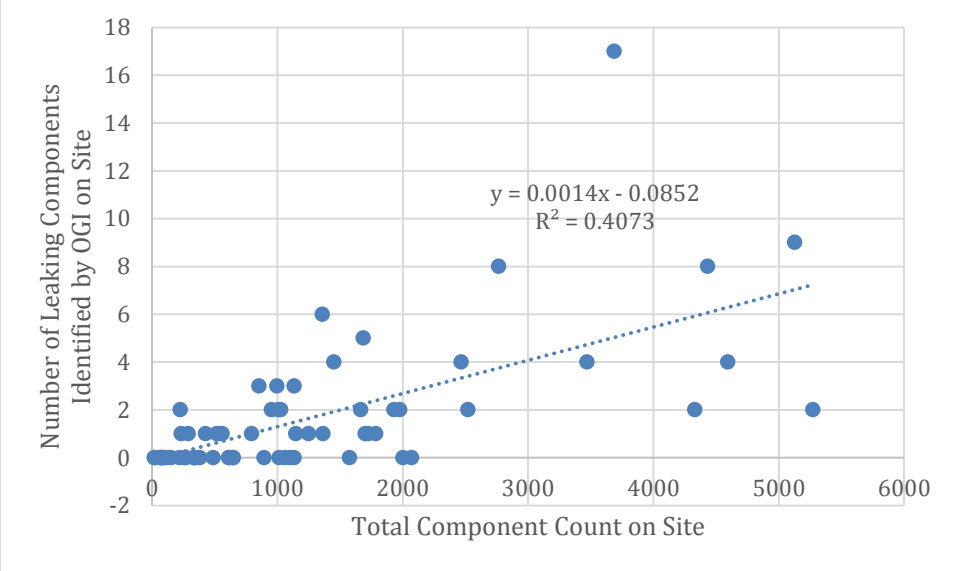

Figure S6. Relationship between site component count and the number of leaks detected by OGI. Graphic shows a weak linear correlation between the number of leaks detected on a site by a given leak detection method and the number of components that were counted at the site by the field team.

Description of Methodology for Comparison to Current EPA Emission Factors

Data from this study was analyzed so that direct comparisons could be made to current EPA emission factors used for reporting greenhouse gas emissions as part of the US Greenhouse Gas Reporting Program (GHGRP) for equipment leaks in the production and gathering and boosting segments for gas and light oil service. The current method that is used mostly frequently (US EPA, 2017a) includes a count of major pieces of equipment located on a site, default factors to estimate component counts based on major equipment counts, and a default population-level emission factor per component type (US EPA, 2017b). In general, comparisons are made between the field determined service (gas versus oil) of each piece of equipment or leaking component and the analogous emission factors from GHGRP methods. Since the API gravity of the oil produced at sites was not recorded as part of the metadata for this study, the assumption is made that all oil service in the study was light oil service rather than heavy oil service. All comparisons in this section are also made to emission factors and component counts in the western United States as all four basins where sampling occurred in this study were in that geographic region, as defined in Table W1-D in 40 CFR 98 Subpart W.

Comparisons between estimated site-level emissions from the current EPA major equipment-based approach and measured emissions from leaking components in this study are made in Table S9. Site-level measured equipment leaks were determined by summing the measured emissions from all leaking components that were identified by OGI or FID-based methods at the 65 sites with both a component count and a leak detection survey. Calculated equipment leaks were estimated by developing a count of major equipment per site and applying default component counts (Table W1-B and C) and default population-level emissions per component (Table W1-A) that are outlined in 40 CFR 98 Subpart W. For major equipment, such as wellheads or separators, that could be in oil or gas service, depending on the application, the classification of the site (oil vs. gas) by the field team was used in deciding which type of wellhead or separator population-level emission factors would be used.

For individual sites, measured emissions from equipment leaks were both higher and lower than suggested by major equipment count-based approaches; however, for most sites and the study overall emissions were overestimated by the major equipment count-based method in 40 CFR 98 Subpart W.

Table S9. Comparison of measured equipment leak emissions from the field campaign to default EPA emission estimation method from major equipment counts. Table compares the 65 sites for which both a component count and LDAR survey were available in this study to the emissions that would have been estimated using methods outlined in 40 CFR 98. Measured emissions represent results of direct measurements of all leaking components identified by OGI or FID.

Site Data				Site Equipment Count							
Site ID	Site Type	Measured Emissions from Leaking Components (scfh)	Calculated Emissions Using Major Equipment Count (scfh)	Wellhead	Separator	Meters/Piping	Compressor	Inline Heater	Dehydrator	Heater Treater	Header
GHD0001	Gas	8.89	8.46	1	1	0	0	0	0	0	0
GHD0002	Gas	0.35	26.09	1	1	0	1	0	1	0	0
GHD0003	Oil	49.99	25.43	2	2	3	1	0	0	4	0
GHD0004	Oil	48.78	26.04	3	2	3	1	0	0	4	0
GHD0005	Gas	46.72	64.78	1	5	0	2	0	1	0	0
GHD0006	Gas	11.00	33.26	1	2	2	1	0	0	0	0
GHD0007	Gas	4.43	43.45	1	4	1	1	0	0	0	0
GHD0008	Gas	0.00	54.22	0	4	1	2	0	0	0	0
GHD0009	Gas	3.19	23.99	1	1	1	1	0	0	0	0
GHD0011	Oil	68.00	88.37	2	4	3	3	12	0	4	0
GHD0013	Gas	6.58	54.12	3	7	1	0	0	0	0	0
GHD0014	Gas	0.95	44.64	1	4	6	0	0	0	0	0
GHD0015	Oil	2.24	6.44	2	6	1	0	0	0	0	0
GHD0016	Gas	65.68	89.45	2	6	3	3	0	0	0	0
GHD0017	Gas	2.43	73.24	0	10	3	0	0	0	0	0
GHD0018	Gas	27.98	76.02	0	10	4	0	0	0	0	0
GHD0019	Oil	79.67	78.85	2	12	7	4	0	0	4	0
GHD0020	Oil	1.90	14.22	0	4	4	0	0	0	2	1
GHD0021	Oil	104.97	110.52	0	20	7	6	0	0	8	6
GHD0022	Gas	0.00	17.50	1	0	1	1	0	0	0	0
GHD0023	Gas	0.00	17.50	1	0	1	1	0	0	0	0
GHD0024	Gas	15.53	27.46	1	0	0	2	0	0	0	0
GHD0025	Gas	0.10	17.50	1	0	1	1	0	0	0	0
GHD0026	Gas	0.00	47.73	0	3	1	2	0	0	0	0
GHD0027	Gas	66.08	90.61	0	2	5	5	0	0	0	0
GHD0028	Oil	9.16	5.02	1	4	1	0	0	0	0	0
GHD0029	Gas	27.43	41.96	2	5	2	0	0	0	0	0
GHD0030	Gas	0.08	17.74	1	2	1	0	0	0	0	0
GHD0031	Gas	45.41	49.94	1	5	1	1	0	0	0	0
GHD0032	Gas	14.78	40.90	1	3	2	1	0	0	2	0
GHD0033	Oil	11.42	6.17	1	4	1	0	0	0	2	0

GHD0034	Oil	1.01	6.17	1	4	1	0	0	0	2	0
GHD0035	Gas	4.54	30.71	1	4	1	0	0	0	0	0
GHD0036	Gas	77.04	69.17	1	6	1	2	0	0	0	0
GHD0037	Oil	1.17	6.17	1	4	1	0	0	0	2	0
GHD0038	Gas	1.13	43.69	1	6	1	0	0	0	0	0
GHD0039	Gas	90.83	46.81	0	2	3	2	0	0	0	0
GHD0040	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0041	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0042	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0043	Gas	266.47	92.49	0	6	2	3	0	2	0	0
GHD0044	Gas	81.13	18.31	0	0	2	1	0	0	0	0
GHD0045	Gas	0.00	1.97	1	0	0	0	0	0	0	0
GHD0046	Gas	0.00	4.76	1	0	1	0	0	0	0	0
GHD0047	Gas	0.00	1.97	1	0	0	0	0	0	0	0
GHD0048	Gas	84.38	135.95	8	8	21	0	0	2	0	0
GHD0049	Gas	18.71	99.92	1	6	13	1	0	2	0	1
GHD0050	Gas	15.53	77.64	1	6	5	1	0	2	0	1
GHD0051	Gas	0.08	17.74	1	2	1	0	0	0	0	0
GHD0052	Gas	1.31	65.83	0	8	5	0	0	0	0	0
GHD0053	Gas	0.09	1.97	1	0	0	0	0	0	0	0
GHD0054	Gas	0.00	1.97	1	0	0	0	0	0	0	0
GHD0055	Oil	0.14	4.21	1	2	1	0	0	0	0	0
GHD0056	Oil	35.81	64.75	0	21	5	3	0	0	6	2
GHD0057	Oil	1.40	1.42	1	2	0	0	0	0	0	0
GHD0058	Oil	5.19	4.21	1	2	1	0	0	0	0	0
GHD0059	Oil	19.37	40.97	0	18	2	2	0	0	4	1
GHD0060	Oil	0.31	1.42	1	2	0	0	0	0	0	0
GHD0061	Oil	3.05	34.44	1	4	2	2	0	0	2	0
GHD0067	Oil	0.00	6.38	0	2	2	0	0	0	0	0
GHD0068	Oil	0.00	0.61	1	0	0	0	0	0	0	0
GHD0069	Oil	0.00	17.86	2	2	1	1	0	0	0	1
GHD0070	Oil	0.36	4.72	0	4	1	0	0	0	0	1
GHD0071	Oil	0.03	0.61	1	0	0	0	0	0	0	0
GHD0072	Oil	0.00	0.61	1	0	0	0	0	0	0	0

Comparisons were also made between the average emissions per component in the field study to default emission factors per component in 40 CFR 98 Subpart W in Table W1-A for gas and light liquid services. The emission factors for this study were developed summing the measured emissions (scfh) for leaking components with an analogous counterpart in Table W1-A (i.e. a valve in gas service) and dividing by the total number of components of that type counted by the

field team in that service across the 65 sites in this study with both a component count and leak detection survey. An implicit assumption of this approach is that all components that were not identified as leaking by either OGI or FID-based surveys are assumed to have negligible emissions, which is similar to EPA approaches for reporting equipment leaks from sites with qualifying LDAR surveys. No measurements were made on these non-leaking components as part of the field campaign to validate this approach. As noted in the paper, the impact of this assumption is expected to be minor, with an estimated addition of 3.4% to measured site emissions from leaking components. Except for open-ended lines (OELs) in gas service, the trend in this study was that average emission factors per component from this study were lower than factors in 40 CFR 98 Subpart W Table W1-A.

Table S10. Comparison of average component emission factors from study to current US EPA factors. Table compares emissions from equipment leaks detected at the 65 sites that also included a site component count. Note that some equipment leak emissions that were attributed to component types not listed in this table, such as a leak on a regulator, are not attributed to component-specific emission factors developed in this table. These emissions are included in other analyses in the paper that consider all equipment leak emissions from site surveys.

	Western U.S. Gas Service					Western U.S. Light Liquid Service			
	Component Count in Study	Emissions from Leaking Components (scfh)	Study Average Emission Factor (scfh/component)	Current EPA Average Emission Factor (scfh/component)	Percent Difference	Component Count in Study	Emissions from Leaking Components (scfh)	Study Average Emission Factor (scfh/component)	Current EP Average Emission Fa (scfh/compon
Valve	8789	286.8	0.033	0.121	-73%	3009	29.6	0.010	0.05
Connector	44491	477.5	0.011	0.017	-37%	14015	16.2	0.001	0.007
OEL	603	135.7	0.225	0.031	627%	128	0.0	0.000	0.05
PRV	512	3.4	0.007	0.193	-97%	77	0.0	0.000	-
Flange	8580	233.0	0.027	-	-	3756	0.0	0.000	0.003

Table S11 shows a comparison between the total components in oil and gas service that were counted by the GHD field team and the estimated component counts that would have been generated from current EPA default component counts in 40 CFR 98 Table W-1B for gas service and Table W-1C for oil service using an EPA online tool for Subpart W reporting for 2017 (EPA, 2018). In general, component counts from the GHD field team were higher than those that would have been estimated from the EPA default component count factors, especially in oil service.

Similar trends were observed based on component count for oil sites and gas sites as with oil service and gas service.

Table S11. Comparison of field component counts to predictions from current EPA estimation methods. Table compares component counts from 65 sites in this study to current EPA default component count estimation methods from the study site major equipment counts.

	Oil and Gas Service			Oil Service		
	Study Field Count	Estimated Count from EPA Methods	Percent Difference	Study Field Count	Estimated Count from EPA Methods	Per
Valves	11798	12816	-8%	3009	1313	
Connectors	58506	36903	59%	14015	2326	
OELs	731	1178	-38%	128	0	
PRVs	589	665	-11%	77	0	
Flanges	12336	2442	405%	3756	2442	
Total	83960	54004	55%	20985	6081	

For the most common equipment leak reporting method in the GHGRP, the US EPA provides default component counts per piece of major equipment (i.e. number of valves per compressor) that are used in emission reporting. Table S12 provides a comparison between the factors developed based on data collected in this study and current EPA factors for the Western United States for gas (40 CFR 98 Table W-1B) and oil (40 CFR 98 Table W-1C) sites for the comparable region in this work. Component counts per piece of equipment are generally higher in this work than the current EPA factors, which is consistent with the overall component counts presented in Table S11.

It should be noted that some of the major equipment listed in the study database does not have an exact match to the types of equipment in current EPA factors. For sites with these types of equipment, such as minor separators like fuel gas scrubbers, the component counts from the unmatched equipment were proportionally allocated to the listed major equipment on site such that the total component counts used in the development of Table S12 were equal to the total component counts reported by the GHD field team and inventoried in the study data.

Care should be taken in making a few comparisons between data collected in this field campaign and current EPA GHGRP factors. First, there is no current factor in the GHGRP for flanges on gas sites, but such components were inventoried in this field campaign. The EPA approach in Subpart W includes flanges under the more general heading of connectors, while this study is presenting results for flanges and other connectors separately. Thus, a direct comparison to the

current EPA factors for gas sites would include the count of both connectors and flanges from this study. Second, the current EPA factors for oil sites includes a factor for "Other components", which is broader than the pressure relief valves (PRVs) in Table S12. A direct comparison to "Other components" cannot be made since the study only inventoried valves, flanges, connectors, open-ended lines (OELs), and PRVs as part of the component counts. It should be noted that leaks identified on-site from other types of non-inventoried components were quantified and included in study emission results presented in this work.

Table S12. Comparison of component counts per major equipment to current EPA component count factors for the Western United States. Table compares component counts per major equipment from 65 sites in this study to current EPA default factors used in GHGRP reporting. Note that the current EPA factors for gas sites do not include flanges, which are rolled-up into connectors in the current reporting program. In addition, oil sites do not have pressure relief valves (PRVs) and have a category labeled "Other components", which includes components beyond PRVs, which were not tracked in this study.

	Components/Major Equipment in Study (Gas)					**Current Subpart W Component Factors (Gas)**				
	Valves	**Flanges**	**Connectors**	**OELs**	**PRVs**	**Valves**	**Flanges**	**Connectors**	**OELs**	**PRVs**
Wellhead	16	11	59	2	1	11	-	36	1	0
Separator	19	10	100	1	1	34	-	106	6	2
Meters/Piping	21	20	51	1	0	14	-	51	1	1
Compressor	24	34	259	3	3	73	-	179	3	4
Inline Heater	4	0	24	0	1	14	-	65	2	1
Dehydrator	26	4	165	0	1	24	-	90	2	2
	Components/Major Equipment in Study (Oil)					**Current Subpart W Component Factors (Oil)**				
	Valves	**Flanges**	**Connectors**	**OELs**	**PRVs**	**Valves**	**Flanges**	**Connectors**	**OELs**	**PRVs**
Wellhead	23	13	134	2	0	5	10	4	0	1
Separator	17	28	87	1	1	6	12	10	0	0
Heater Treater	18	24	91	1	1	8	12	20	0	0
Header	30	51	37	0	0	5	10	4	0	0

For 2017 emission reporting into the GHGRP, a new methodology for reporting equipment leaks was introduced as an option for oil and gas production and gathering and boosting sites. This methodology is based on counts of leaking components that are identified through a qualifying field leak detection survey, such as with OGI and FID-based methods, and a leaker emission factor from 40 CFR 98 Subpart W Table W1-E. The number of leaks and leaker emission factor is used to estimate site equipment leak emissions for each component type. Emissions from other components on site are assumed to be negligible. Leaker emission factors were developed for

leaking components identified in this study and compared to the equivalent leaker emission factors from Table W1-E.

Comparison of the leaker emission factors developed in this study to those in Table W1-E indicate the average emissions per leaking component in gas service (Table S13) were larger in this study than in the datasets used to develop the current EPA emission factors. Comparisons for emissions from leaking components identified in oil service (Table S14) were more varied than for gas service. Further comparisons are made to EPA-derived leaker emission factors (EPA, 2016) based on a 2013 study (Allen et al. 2013) and the Fort Worth Air Quality Study (City of Fort Worth, 2011) for components in gas service. In general, the resulting leaker emission factors from measurements in this study were lower than the factors developed from either of those study datasets.

Table S13. Comparison of study and EPA leaker emission factors for natural gas service. Table compares the emissions per leaking component measured in this study to data from other publicly-available sources.

Component Type	Number of Leaking Components	Emissions from Leaking Components (scfh)	Leaker Emission Factors in Gas Service (scfh/leaking component)			
			Study Factor	Current EPA Factor	EPA Analysis of Allen (2013) Study	EPA Analysis of Fort Worth Air Quality Study
Valve	48	287.4	6.0	4.9	7.6	12.2
Flange	17	233.0	13.7	4.1	9.6	14.4
Connector	173	484.8	2.8	1.3	3.3	5.4
OEL	16	135.7	8.5	2.8	21.8	10.6
PRV	3	3.4	1.1	4.5	9.8	-
Pump Seal	0	-	-	3.7	-	-
Other	50	212.4	4.2	4.5	3.8	9.5

Table S14. Comparison of study and EPA leaker emission factors for oil service. Table compares the emissions per leaking component measured in this study to data from other publicly-available sources.

Component Type	Number of Leaking	Emissions from	Leaker Emission Factors in Oil Service (scfh/leaking component)

	Components	Leaking Components (scfh)	Study Factor	Current EPA Factor
Valve	6	29.6	4.9	3.2
Flange	0	-	-	2.7
Connector	14	16.2	1.1	1
OEL	0	-	-	1.6
Pump	1	0.23	0.23	3.7
Other	3	38.0	12.7	3.1

Comparisons of Percent of Components Identified as Leaking

Some equipment leak studies (e.g. Allen et al., 2013) have simply noted the types and emission quantity for identified leaking devices. Other studies (e.g. Kuo et al., 2015) have also conducted overall component counts to aid in the development of component-specific population emission factors and to understand the frequency of leaking components from the general population of components.

As part of contextualizing the study results related to the percent of components counted in the survey that were identified as leaking, the origin of the current factors used in EPA Subpart W GHGRP reporting was examined. For gas service, the population emission factors were adopted from a 1996 Gas Research Institute (GRI) and EPA study (Hummel et al., 1996) that utilized population component counts, leaking component counts, and FID screening values from a 1995 API study (API, 1995). Emissions from leaking components in gas service were estimated from correlation equations developed from an EPA emission estimation protocol (EPA, 1995). For light and heavy crude services, population emission factors for Subpart W emission reporting were developed directly from emission and population data in the 1995 API study (API, 1995).

Table S15 compares the fraction of components that were identified as leaking in prior research studies as a point of comparison for the results in this work. It is important to point out that the underlying studies referenced may have included different definitions of leak thresholds (100 ppm or 10,000 ppm) versus the assumption used in this work (500 ppm). Table S15 includes analysis of the underlying source data such that comparisons are made on the same leak definition for sites with a component count and FID-based survey. The rate of FID-determined leaking components at 500 ppm and 10,000 ppm thresholds were much lower (0.4% to 0.3% of components surveyed) than previous API study results (2.8% to 1.1% of components surveyed).

Table S15. Comparison of the fraction of leaking components identified in previous equipment leak estimation studies. Note that the analysis presented required a re-analysis of some of the source information for referenced sources since the leak threshold definition was not always consistent between studies. Leaking and overall component counts are based on the subset of sites with both an FID survey and a full site component count.

Reference	Source Description	Component Count in Population	Leaking Component Count		Leaking Component Frequency in Population	
			>500 ppm	>10,000 ppm	>500 ppm	>10,000 ppm
API 1995	Onshore Gas Production	40,178	1,138	648	2.83%	1.61%
API 1995	Onshore Oil Production	62,408	673	419	1.08%	0.67%
API 1995	Onshore Oil and Gas Production	102,586	1,811	1,067	1.77%	1.04%
This Study	Onshore Gas Production	46,140	173	82	0.37%	0.18%
This Study	Onshore Oil Production	36,134	117	56	0.32%	0.15%
This Study	Onshore Oil and Gas Production	82,274	290	138	0.35%	0.17%

Section S4. Supplemental Material References

Allen DT, Torres VM, Thomas J, Sullivan DW, Harrison M, et al. 2013. Measurements of methane emissions at natural gas production sites in the United States. *P Natl Acad Sci USA* **110**: 17768-17773. DOI: 10.1073/pnas.1304880110.

American Petroleum Institute (API). 1993. Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations. API Publication Number 4589.

Bacharach. 2015. HI FLOW® Sampler, Natural Gas Leak Rate Measurement Instruction 0055-9017, Operation & Maintenance, Rev. 7 – July 2015.

Brantley HL, Thoma ED, Eisele AP. 2015. Assessment of volatile organic compound and hazardous air pollutant emissions from oil and natural gas well pads using mobile remote and on-site direct measurements. *Journal of the Air and Waste Management Association,* 65:9, 1072-1082. DOI: 10.1080/10962247.2015.1056888

City of Fort Worth. 2011. Natural Gas Air Quality Study (Final Report). Fort Worth, Texas. http://fortworthtexas.gov/gaswells/air-quality-study/final/.

Howard T, Ferrara TW, Townsend-Small A. 2015. Sensor transition failure in the high-volume sampler: Implications for methane emission inventories of natural gas infrastructure. *Journal of the Air and Waste Management Association,* 65:7, 856-862. DOI: 10.1080/10962247.2015.1025925.

Hummel KE, Campbell LM and Harrison MR. 1996. Methane emissions from the natural gas industry, volume 8: equipment leaks. Austin, Texas: Radian International LLC. Report: EPA-600/R-96-080h.

Indaco Air Quality Services, Inc., 1995, A High Flow Rate Sampling System for Measuring Leak Rates at Natural Gas Facilities. Report No. GRI94/0257.38. Gas Technology Institute, Chicago, Illinois.

Kimray Inc. 2013. Glycol Pumps. https://kimray.com/products/browse/itemdetail/2283.

Kuo J, Hicks TC, Drake B, and Chan TF. 2015. Estimation of methane emission from California natural gas industry. *J Air Waste Ma* **65**: 844-855. DOI:10.1080/10962247.2015.1025924.

Modrak MT, Amin MS, Ibanez J, Lehmann C, Harris B, Ranum D, et al. 2012. Understanding direct emission measurement approaches for upstream oil and gas production operations. *Proceedings of the Air & Waste Management Association 105th Annual Conference & Exhibition*, San Antonio, TX, June 19–22. Available at http://portal.awma.org/store/detail.aspx?id=411ACE12.

U. S. Environmental Protection Agency (EPA) 1995. 1995 Protocol for Equipment Leak Emission Estimates. Publication No. EPA-453/R-95-017

U.S. Environmental Protection Agency (EPA). 2016. Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule. Washington, District of Columbia. Docket ID No. EPA-HQ-OAR-2015-0764.

U.S. Environmental Protection Agency (EPA). 2017a. Envirofacts – Greenhouse Gas Customized Search. Washington, District of Columbia. https://www.epa.gov/enviro/greenhouse-gas-customized-search.

U.S. Environmental Protection Agency (EPA). 2017b. 40 CFR 98 Subpart W – Petroleum and Natural Gas Systems. Washington, District of Columbia.

U.S. Environmental Protection Agency (EPA). 2018. Confluence: Optional Calculation Spreadsheet Instructions. https://ccdsupport.com/confluence/display/help/Optional+Calculation+Spreadsheet+Instructions.