**Supplementary Materials for:**

# Closing the gap: Explaining persistent underestimation by US oil and natural gas production-segment methane inventories

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This document includes:

# 1. Study scope and definitions

This study makes three contributions to the literature, each discussed in greater detail in Supplementary Information sections 3-5.

1. Development of a bottom-up $CH_4$ emissions estimation tool: In Section 3 we describe the bottom-up tool used in this study. First, we outline the underlying dataset which is composed of quantified emissions measurements, component counts, and fraction leaking estimates. Second, we describe the implementation of the tool as a subroutine in the life-cycle assessment model, OPGEE.

2. Generating a bottom-up estimate of US production-segment $CH_4$ emissions: In Section 4 we describe how our estimation tool, implemented in OPGEE, is used to produce an estimate of US $CH_4$ emissions from the production segment of the O&NG industry. This required development of a well-level dataset for implementation in our tool. For comparison with previous site-level results, we developed a site-level clustering algorithm which is also discussed in Section 4.

3. Derivation of Greenhouse Gas Inventory emission factors: The final contribution of this paper is an analysis of the EPA's emission factors applied in the Greenhouse Gas Inventory, described in Section 5. Through a literature review, we begin with the underlying datasets of quantified component-level emissions and reconstruct the emission factors found in the most recent inventory. Emission factors are compared with the emission factors applied in our tool.

## 1.1. System Boundary

Our analysis boundary contains oil and natural gas (O&NG) production sites delivering marketable NG (including both associated and non-associated gas). We will refer to this as the production segment, which includes all equipment associated with a well pad and ends prior to centralized gathering and processing facilities (**Figure S1**). We limit our analysis to the production segment as this is the largest contributor to the divergence in emissions estimates between the GHGI and previous site level analyses [1] (**Figure S2**).

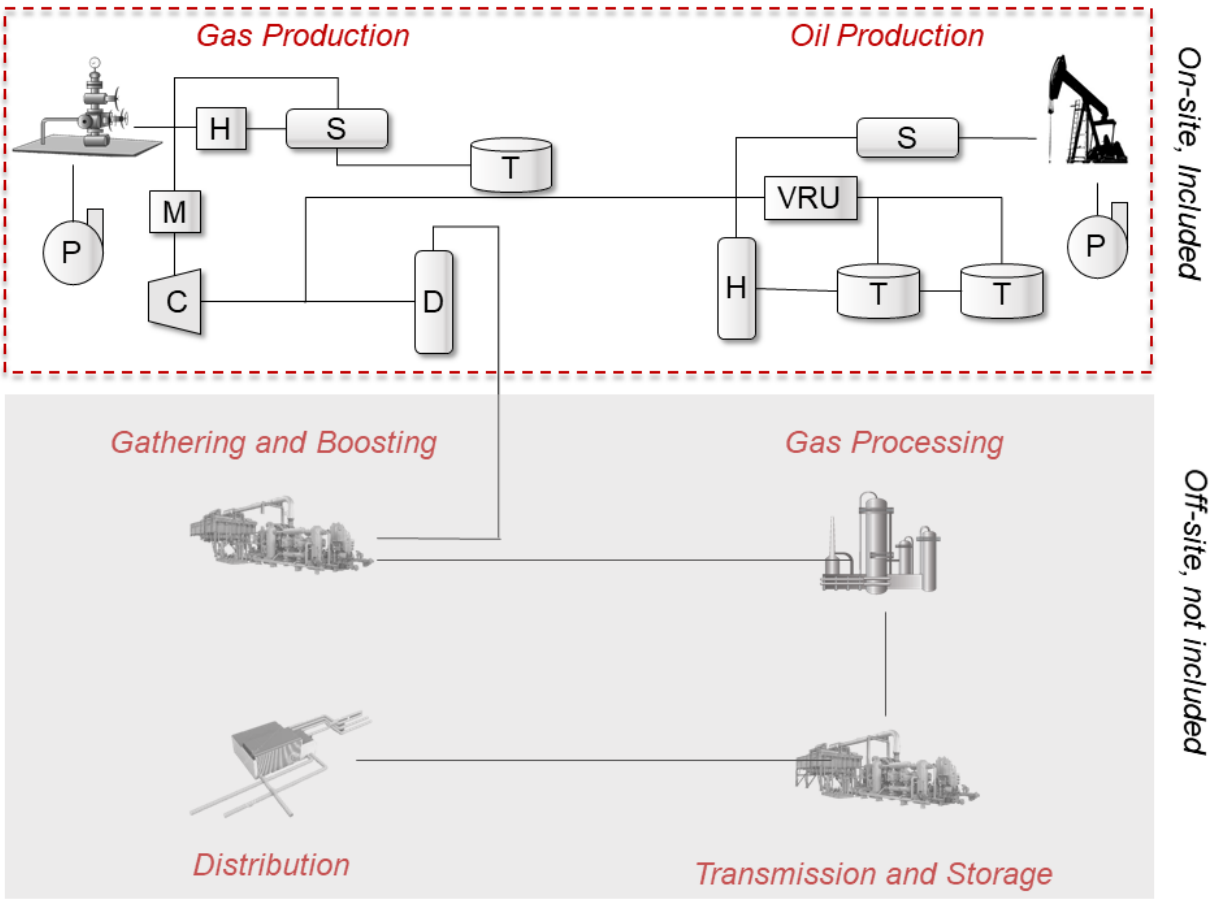


**Figure S1: The NG supply chain. This study will focus on the production segment, indicated in the figure with a red hashed box (H = heater, S = separator, T= tank, M = meter, P = pump, C = compressor, D = dehydrator, VRU = vapor recovery unit).**

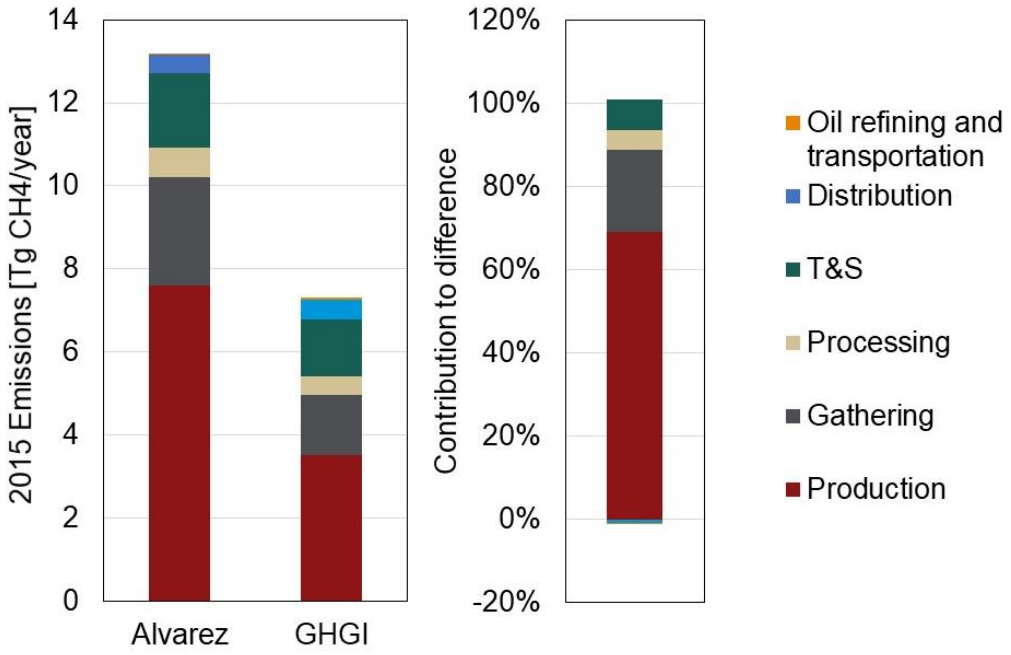


**Figure S2: Comparison of total O&NG supply chain $CH_4$ emissions estimates between Alvarez et al.** [1] **and the EPA GHGI (**[2] **,reporting year 2015). Right panel is percent contribution of supply chain segments to total difference.**

We assess all emissions associated with production segment equipment. Categorization of equipment considers both capabilities of our model as well as categorization in the EPA Greenhouse Gas Inventory (GHGI). These categories are defined as follows:

- *Equipment leaks*: This category includes all component-level emissions associated with wellheads, separators, dehydrators, meters, reciprocating compressors, heaters, headers, chemical injection pumps. When aggregating GHGI data, dehydrator vents are also included in this category. Therefore, the term "leaks" should be interpreted loosely. Often studies will disaggregate emissions on the basis of fugitives (unintentional emissions) and vents (intentional emissions). We do not do so, given that measurements in emissions quantification studies are often not labeled as fugitives or vents.

- *Pneumatic controllers*: Pneumatic controllers are found on various types of equipment. These components use gas pressure to actuate valves automating operation of flow, pressure, or liquid level. As the control valve is opened and closed, gas may be vented. Although pneumatic controllers are technically components (versus an equipment unit) the GHGI classifies pneumatic controller emissions separately instead of to the equipment on which they are installed. We follow this convention in this study.

- *Tanks*: Several types of emissions occur from crude and condensate storage tanks. Like other equipment, leaks occur through connectors, valves, and other components. Other venting mechanisms include "working and breathing losses" (solution gas evolved due to changes in temperature and pressure), "flashing losses" (solution gas released when liquids are dumped from the separator), or losses due to equipment malfunction (e.g., stuck dump valve on the separator).

- *Methane slip*: Small reciprocating compressors located on well pads have two types of emissions not found on other equipment: (i) leaks from rod-packing or centrifugal seals, and (ii) incomplete combustion from the gas engines used as prime movers. Leaks from rod-packing, seals, and other components are classified in the "equipment leaks category". Methane slip refers to emissions associated with incomplete combustion.

- *Liquids unloadings*: Liquids unloadings are a type of infrequent emissions source and not all wells perform liquids unloadings. A liquids unloading is a procedure implemented periodically on gas producing wells to removed unwanted liquids (e.g., water, condensate, oil) from the well tubing using either a pump or by temporarily diverting flow to an atmospheric pressure tank to reduce the backpressure normally seen by the fluids and thereby inducing flow.

- *Completions and workovers*: Completions and workovers are another type of infrequent emissions source. A well completion is the process of transforming a drilled well into a producing well. Often a "completion" refers to the casing, cement, and wellhead assembly process, which are required before beginning production. During the well completion process, drilling mud, sand, and liquids must be removed from the well-bore. Gases, including methane, will be dissolved in the flowback liquids. These gases are either captured with flowback emission control devices or are emitted. After a well is completed, a workover may be required if equipment needs servicing or the well isn't producing efficiently. Like a completion, workovers can result in flowback-related emissions.

## 2. Harmonized comparison of emission factors and activity factors

An objective of this study, which will be discussed in greater detail in later sections (see Section 5), is the decomposition of emissions into the constituent component-level and equipment-level factors (see **Figure 1**, main text). The purpose of these decompositions is for a harmonized comparison with emissions estimates of the GHGI. Throughout this work, we discuss calculation of emissions at the component-level and at the equipment-level. We also make comparisons with various studies conducted at the well-site-scale. These terms are defined as follows:

- Component- The basic constituent parts of equipment which serve either mechanical (e.g., connector) or control (e.g., valve) purposes. A piece of equipment can have 10s to 100s of components.

- Equipment – An assemblage of components fit for a specific purpose of O&NG production, processing, or delivery. For example, a separator is a piece of equipment that separates fluids based on density to allow separate treatment of gases, liquid hydrocarbons, and water.

- Well-site – A well-site (also often referring to as a well-pad, production-site, or production-facility) refers to the set of equipment necessary for O&NG production. This will include one or more wells and ancillary production equipment for handling, separation, and delivery of product to market or a centralized gathering facility. In some cases, a well-site will contain compression equipment in order to meet pressure requirements for delivery of gas off-site.

In both our approach and the approach of the GHGI, total emissions are calculated through two successive extrapolations, first from the component-level to the equipment-level, and second from the equipment-level to the national-level (**Figure 1,** main text). Extrapolations are performed by multiplying emission factors by activity factors, defined as follows:

- Emission factor (EF) – Average mass of pollutant per unit activity. Activities are often defined as operation of a component for a unit of time, resulting in emission factors with units such as $kgCH_4$/flange/d.

- Activity factor (AF) – Usually defined as the number of sources (e.g., counts of equipment or components). However, there are certain cases where emissions are more accurately scaled by a different metric (e.g., horsepower-hours for gas engines).

Therefore, differences between our study and the GHGI can be deduced by comparing emission factors and activity factors at both the equipment-level and component-level. This section serves to accompany the discussion included in the main text. Here, we include tabular comparisons of values with reference to other relevant sections in this supplementary information.

## 2.1.Component-level factors

Component-level emission factors are averages of component-level emissions survey datasets. Our first harmonized comparison is of our component-level emission factors with the data underlying the GHGI [3]–[5]. As we elaborate in the main text and in Section 5, the GHGI is

itself based upon the results of multiple component-level datasets. In **Table S1** we compare emission factors reported by these various studies, including API 4598 [3], Star Environmental [4], and the EPA Protocol document [5], with the emission factors generated in this study. For further description of these studies, please refer to section 5.2.

We also compare emissions factors reported in 40 CFR part 98, subpart W (referred to as "Subpart W" [6]) for the calculation of equipment leakage in the Greenhouse Gas Reporting Program. In Subpart W, there are three different methods of calculating equipment leakage (referenced in **Table S1**). These methods include both "population" emission factors and "leaker" emission factors. Population emission factors (as we describe above) are an average across both emitting components and non-emitting components. Therefore, operators calculate emissions by multiplying component counts at a facility by the population emission factors (referred to as "pop." in **Table S1**). In addition to population emission factors, Subpart W also includes two approaches which involve "leaker" emission factors. Leaker emission factors are an average across only emitting components. In these approaches, operators count total emitting components by either (ii) an optical gas imaging approach, or (iii) a Method 21 approach with a leak threshold of 500 ppmv (referred to as "Leaker method (i)" and method "Leaker method (ii)", respectively, in **Table S1**).

**Table S1: Comparison of component-level emission factors (units of kg$CH_4$/component/day) generated in this study with 1990s EPA emission factors, including API 4598** [3]**, Star Environmental** [4]**, and the EPA Protocol document** [5]**, and emissions factors applied in Subpart W** [6]**. Population emission factors (Pop.) are calculated as the average across both leaking and non-leaking components, while "leaker" emission factors are an average of only leaking components. In both this study and the EPA Protocol document, "leaker" emission factors are calculated according to a threshold concentration screening value (see Section 3.2.4).**

| | | API 1993 (doc. 4598) [3] | Star Environmental [4] | | EPA Protocol Document [5] | | | Subpart W [6][1] | | | This study | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Pop. | Leaker | Pop. | Ave. >10,000 ppmv | Pegged > 10,000 ppmv | Pop. | Leaker method (i) | Leaker method (ii) | Pop. | Ave. > 10,000 ppmv |
| Gas | Valve | 0.044 | 0.007 | 0.544 | 0.074 | 1.616 | 1.055 | 0.010 | 1.782 | 1.273 | 0.047 | 6.205 |
| | Connector | 0.002 | 0.001 | 0.073 | 0.003 | 0.429 | 0.462 | 0.001 | 0.473 | 0.291 | 0.006 | 3.326 |
| | OEL | 0.004 | 0.020 | 0.116 | 0.033 | 0.907 | 0.495 | 0.022 | 1.018 | 0.691 | 0.021 | 2.356 |
| Light oil | Valve | 0.005 | - | - | 0.037 | 1.434 | - | 0.018 | 1.164 | 0.800 | - | - |
| | Connector | 0.001 | - | - | 0.003 | 0.429 | - | 0.003 | 0.364 | 0.218 | - | - |
| | OEL | 0.010 | - | - | 0.021 | 0.725 | - | 0.018 | 0.582 | 0.400 | - | - |
| Heavy oil | Valve | 8.6E-05 | - | - | 1.9E-04 | - | - | 1.8E-04 | 1.164 | 0.800 | - | - |
| | Connector | 4.3E-05 | - | - | 1.7E-04 | - | - | 1.1E-04 | 0.364 | 0.218 | - | - |
| | OEL | 4.3E-04 | - | - | 3.2E-03 | 4.9E-01 | - | 2.2E-03 | 0.582 | 0.400 | - | - |

[1]See Tables W-1A for population emissions factors and W-1E for leaker emissions factors in [6]

## 2.2.Equipment-level factors

Equipment-level emission factors are calculated by summing component-level emission factors according to estimated component counts per piece of equipment using methods described in Section 3.3 for this study and Section 5.2 for the GHGI. Equipment-level activity factors are applied to extrapolate equipment-level emission factors to estimate total emissions. **Table S2** and **Table S3** present a harmonized comparison of equipment-level emission factors and activity factors between our study and the GHGI for natural gas systems and petroleum systems, respectively. Aggregated emission factors were weighted according to equipment counts.

Because emission factors for storage tanks are reported by the GHGI on a throughput basis (kg/Mbbl), we perform a rough conversion for comparison with this study's emission factors. Total GHGI storage tanks are estimated using the same activity factors as this study (**Table S13**). Storage tank emissions are divided by activity to estimate an emission factor in kg/day. Equipment-level emission factors for this study are separately assigned to marginal wells (<10 mscf/well/day) and non-marginal wells as described in Section 3.3.1.

Emission factor probability distributions are presented in **Figure S3**.

**Table S2: Harmonized comparison of activity factors, emission factors, and total emissions between this study and the Greenhouse Gas Inventory for natural gas systems. For this study, we present post hoc emission factors (i.e., averages of emissions randomly assigned by OPGEE's iterative bootstrapping algorithm, see section 3.3.1) for marginal wells (<10 mscf/well/day) and non-marginal wells in addition to average emission factors.**

| | Natural gas systems | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | This study | | | | | Greenhouse Gas Inventory (GHGI) | | |
| | Activity factor [# equipment] | Emission factor - Marginal [kg/day] | Emission factor- Non-marginal [kg/day] | Emission factor - Average [kg/day] | Total emissions [Gg] | Activity factor [# equipment] | Emission factor [kg/day] | Total emissions [Gg] |
| Well heads | 433,430 | 1.5 | 4.4 | 3.3 | 529.4 | 419,692 | 0.3 | 49.1 |
| Header | - | - | - | - | - | - | - | |
| Heater | 54,489 | 1.1 | 3.3 | 2.5 | 49.8 | - | 0.7 | 13.5 |
| Separator | 300,197 | 1.4 | 4.4 | 3.4 | 367.3 | 298,108 | 1.1 | 118.4 |
| Meter | 350,563 | 1.2 | 3.5 | 2.7 | 343.8 | 351,867 | 0.6 | 73.4 |
| Tanks - Leaks | 175,106 | 0.9 | 2.8 | 2.1 | 135.7 | - | - | - |
| Tanks - Vents | 175,106 | 2.1 | 11.1 | 7.9 | 503.6 | - | - | - |
| Compressor - Recip | 10,118 | 2.8 | 7.2 | 5.6 | 20.7 | 54,977 | 5.5 | 73.2 |
| Dehydrator | 11,976 | 1.2 | 3.4 | 2.6 | 11.4 | 12,463 | 1.3 | 29.0 |
| Chemical Injection Pump | 77,151 | - | - | - | 0.0 | 74,506 | 4.2 | 113.3 |
| Pneumatic Controller | 1,300,290 | 1.1 | 2.5 | 2.0 | 959.0 | 833,222 | 3.5 | 1072.7 |
| Liquids unloadings | 75,850 | 4.5 | 11.2 | 8.8 | 244.7 | 73,378 | 6.0 | 160.1 |
| completion | 6,069 | - | - | 5495.0 | 33.3 | 6,069 | 4057.2 | 38.2 |
| workover | 10,090 | - | - | 639.0 | 6.4 | 10,090 | 1261.9 | 12.7 |
| Tank flashing | 175,106 | 0.0 | 0.2 | 0.2 | 10.0 | - | 0.9 | 24.7 |
| Combustion | 9,969 | - | - | 7.7 | 27.8 | 54,977 | 13.2 | 265.0 |

*Completion and workover emissions factors are reported in units kg/event

** Other emissions adding to 173 Gg are included in the GHGI but not listed here. This include produced water tanks, kimary pumps, dehydrator vents, onshore flaring and venting, blowdowns and upsets, and pipelines.

**Table S3: Harmonized comparison of activity factors, emission factors, and total emissions between this study and the Greenhouse Gas Inventory for petroleum systems. For this study, we present post hoc emission factors (i.e., averages of emissions randomly assigned by OPGEE's iterative bootstrapping algorithm, see section 3.3.1) for marginal wells (<10 mscf/well/day) and non-marginal wells.**

| | Petroleum systems | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | This study | | | | | Greenhouse Gas Inventory (GHGI) | | |
| | Activity factor [# equipment] | Emissions factor - Marginal [kg/day] | Emissions factor- Non-marginal [kg/day] | Emissions factor - Average [kg/day] | Total emissions [Gg] | Activity factor [# equipment] | Emissions factor [kg/day] | Total emissions [Gg] |
| Well heads | 571,759 | 0.7 | 3.1 | 1.5 | 306.8 | 600,519 | 0.3 | 65.3 |
| Header | 131,505 | 1.6 | 7.5 | 3.5 | 170.3 | 138,236 | 0.2 | 8.0 |
| Heater | 104,253 | 0.4 | 2.4 | 1.1 | 42.1 | 114,278 | 0.4 | 44.3 |
| Separator | 200,233 | 0.6 | 3.6 | 1.6 | 118.4 | 215,830 | 0.2 | 19.0 |
| Meter | - | - | - | - | - | - | - | - |
| Tanks - Leaks | 428,819 | 0.3 | 1.4 | 0.7 | 105.8 | - | - | - |
| Tanks - Vents | 428,819 | 1.2 | 10.2 | 4.2 | 656.0 | - | - | - |
| Compressor - Recip | - | - | - | - | - | - | - | - |
| Dehydrator | - | - | - | - | - | - | - | - |
| Chemical Injection Pump | 54,317 | - | - | - | - | - | - | - |
| Pneumatic Controller | ######## | 0.7 | 2.4 | 1.3 | 793.6 | 623,264 | 3.5 | 789.5 |
| Liquids unloadings | - | - | - | - | - | - | - | - |
| completion | 15,745 | - | - | 6744.5 | 106.2 | 15,746 | 4701.4 | 74.0 |
| workover | 1,243 | - | - | 2234.5 | 2.8 | 31,772 | 367.1 | 12.7 |
| Tank flashing | 428,819 | 0.3 | 12.6 | 4.4 | 695.4 | - | 0.4 | 67.7 |
| Combustion | - | - | - | 0.0 | - | - | - | - |

*Completion and workover emissions factors are reported in units kg/event
** Other emissions adding to 82 Gg are included in the GHGI but not listed here. This include produced water tanks, kimary pumps, dehydrator vents, onshore flaring and venting, blowdowns and upsets, and pipelines.

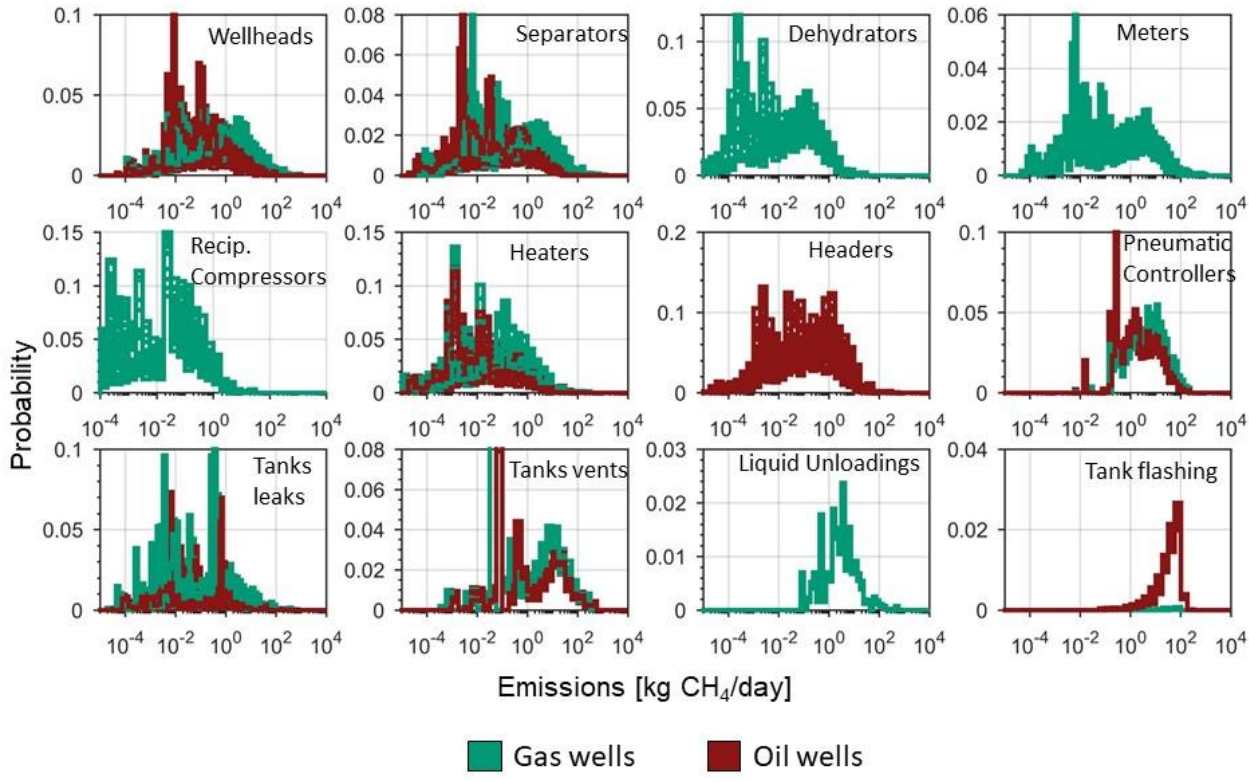


**Figure S3: Probability distributions of equipment-level emission factors comparing gas sites (GOR > 100 mscf/bbl) and oil sites (GOR < 100 mscf/bbl).**

## 2.3. Differences mostly explained by emission factors

With only a couple exceptions (pneumatic controllers and compressors), equipment-level activity factors applied in this study are generally very close (< 5% differences for natural gas systems and < 10% differences for petroleum systems) to those applied in the GHGI. Exceptions include (with reference to **Table S2** and **Table S3**):

- Compressors (relevant to both compressor leaks and methane slip): Concerns have been reported by Marchese et al. [7] that the GHGI does not properly allocate equipment counts between the production segment and the gathering and boosting segment. Marchese et al. [7] suggest only allocating 29% of reporting small reciprocating compressors to the production segment (see **Table S13**).
- Pneumatic controllers: Our count of pneumatic controllers per well is much higher compared to the GHGI based upon data reporting by Allen et al. [8].
- Tanks: The GHGI calculates tank emissions on a throughput (Mbbl/day) activity basis. Therefore, we don't include a tank activity count for the GHGI.

On the other hand, wide differences exist with equipment-level emission factors (~1x to 12x for natural gas systems and ~1x to 50x for petroleum systems). This suggests that understanding disagreements between results of this study and the GHGI can be explained through an investigation of equipment-level emission factors and not activity factors.

## 3. Development of the bottom-up $CH_4$ emissions estimation tool

The analysis platform for this study is the component-level methane venting and fugitives (VF) subroutine embedded within OPGEE 3.0. This subroutine processes inputs from external databases – specifically equipment-level emissions distributions and well and production values and produces gross emissions estimates.

In this section, we will begin by describing the existing OPGEE 3.0 functionality (Section 3.1). Next, we will describe the underlying database of component-level data (Section 3.2) and how equipment-level emission factors were developed from this data (Section 3.3). We will conclude this section by describing equipment-level activity factors (Section 3.4).

Below is a flowsheet, **Figure S4**, which illustrates the OPGEE 3.0 VF subroutine.

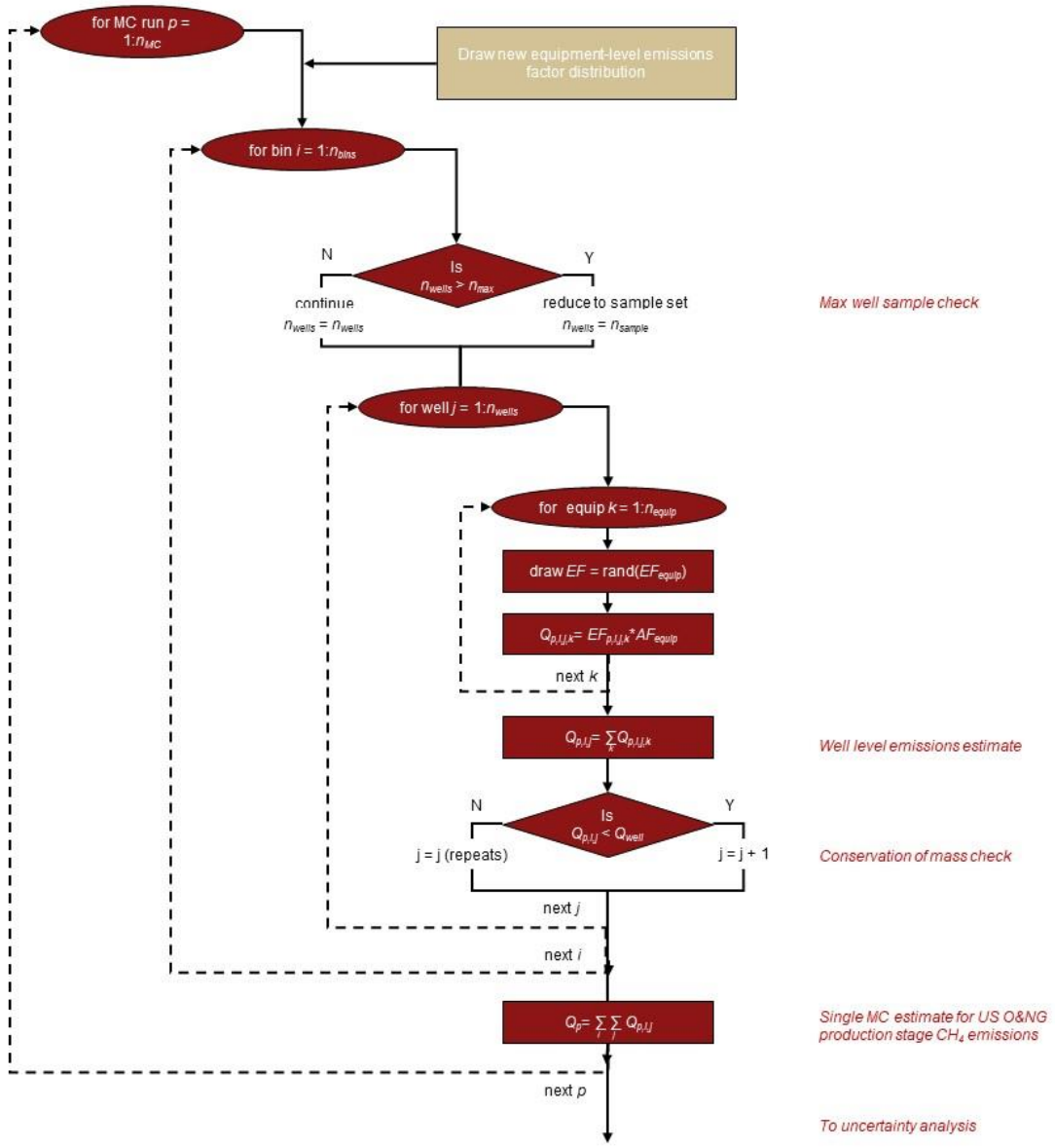


**Figure S4: Pseudocode block diagram of OPGEE's $CH_4$ venting and fugitives calculator**

## 3.1. Structure of the OPGEE component-level methane emissions model

**Figure S5** illustrates how the component-level VF subroutine, represented by the simple equation, fits into the broader OPGEE platform. Inputs to the VF subroutine are linked from the *Inputs sheet*. OPGEE generates outputs (carbon intensity or methane leakage rate) on a "field" basis, where a "field" represents an O&NG system with unique properties. In our case, "fields" are the

productivity tranches/bins, described in Section 4.1. For each "field" *i*, emissions are calculated well-by-well. For each well *j*, equipment-level emissions are calculated by multiplying a randomly drawn emissions factor, $EF_{i,j,k}$, by its respective activity factor, $af_k$. Emissions results from the *Calculation table* are stored in a separate table by the *Fugitives macro*, which iterates to the next well. These separate elements of the OPGEE VF subroutine will be described in the following sections.

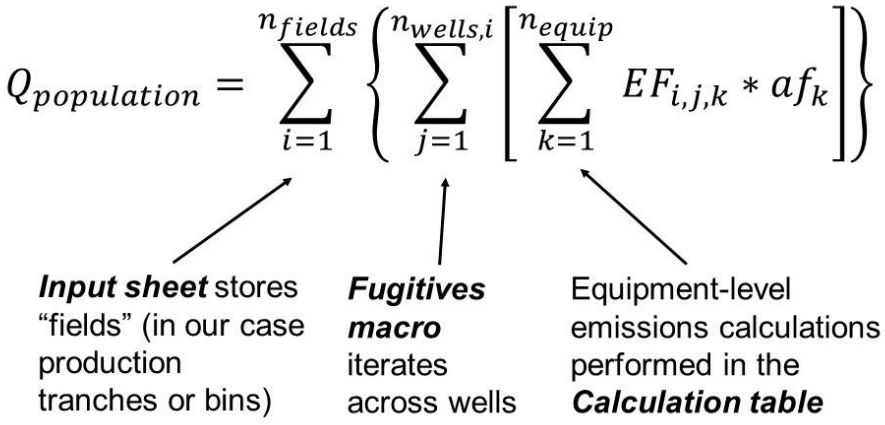


**Figure S5: Graphical illustration of OPGEE 3.0 VF algorithm**

### *3.1.1. Worksheet*

**Figure S6** provides an overview of the OPGEE 3.0 component-level VF worksheet. User interaction will typically be limited to the Inputs, Summary table, and *Calculations table*. The emissions factor distributions and activity factors are accessed by built in functions in the *Calculations table*. In this section we will describe the Inputs and *Calculations table* in more detail. For more information on the activity factors and emissions factors, please reference sections 3.3 and 3.4.

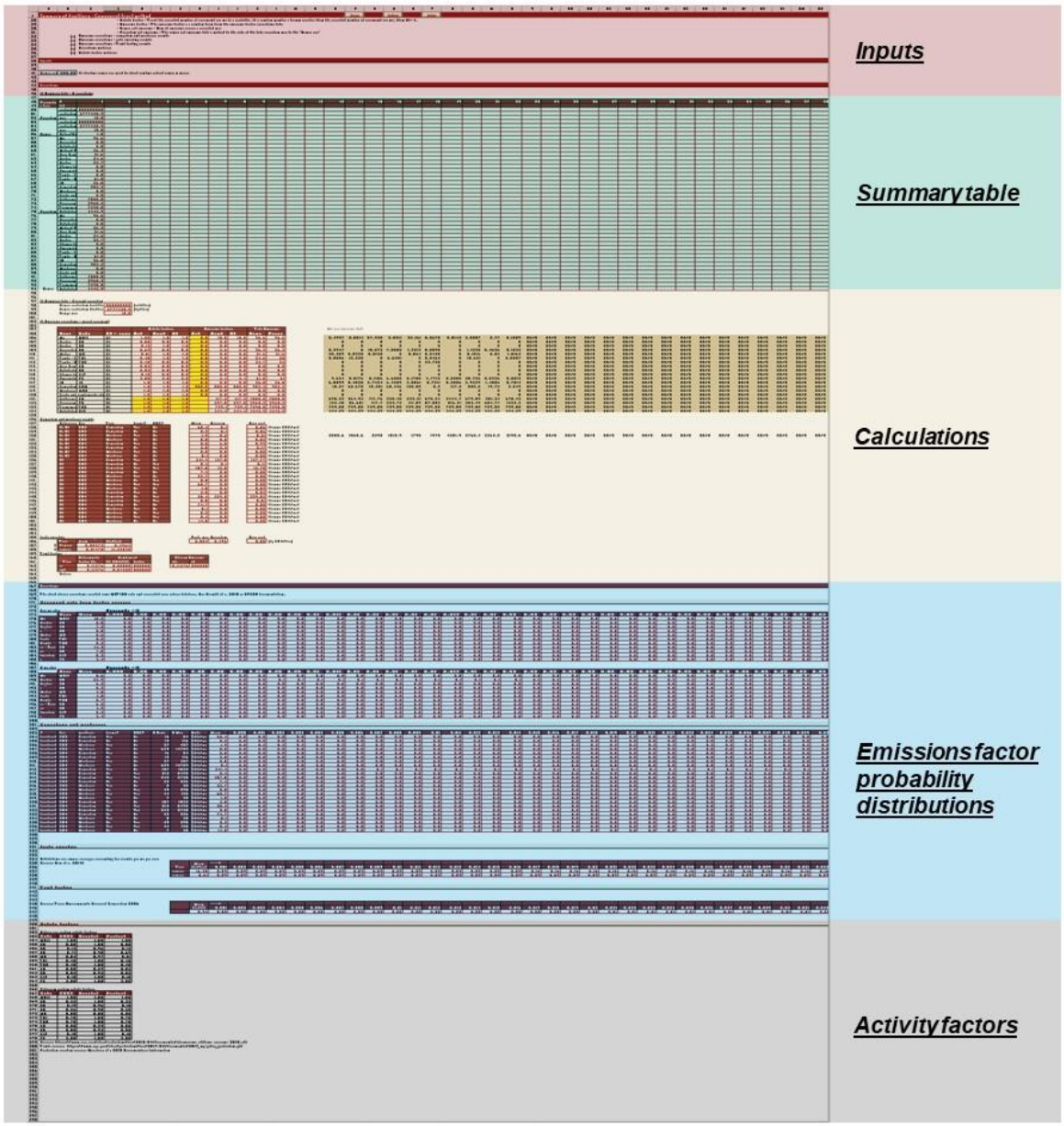


**Figure S6: Zoomed-out and labelled view of the OPGEE 3.0 component-level VF worksheet**

*Inputs*

In the Inputs section, we include a "Sample size" parameter, designed to reduce OPGEE processing time. The "Sample size" parameter sets an upper limit on the number of wells that the OPGEE *Fugitives macro* will process. If the total number of wells is greater than "Sample size", an extrapolation is performed (more details below). By default, we set the max well sample to be

500 wells. This gives accurate summary statistics and distributions for a tranche/field, but limits the iterations that would be required in modeling a tranche/field with 1000s of wells.

*Calculation table*

The *Calculation table* is set up with rows containing all supply chain emissions sources and columns containing the emissions calculation parameters (**Figure S7**). Calculation parameters include a methods code (referencing the calculation method applied), emissions factors, activity factors, and total emissions. The methods code is required because the component tool distinguishes between on-site and off-site equipment. This is because in its current iteration the component tool only applies the component-level method to the production segment. Off-site segments (gathering and boosting, transmission, and distribution) apply the site-level method. For these sections, we apply fractional loss rates found in several facility-level studies ([1], [9], [10]). Calculation of the life cycle emissions is required for the purposes of the mass balance calculation in the macro (see next section).

The total emissions column is divided into sample emissions and population emissions. Sample emissions are calculated by simply summing across all the well realizations performed. However, since the maximum wells calculations per field are limited to 500 (unless adjusted by the user), the total emissions may need to be adjusted. The population emissions are equal to the sample emissions multiplied by the population well count divided by 500 (or user-defined sample size).

| | | | Activity Factors | | | Emissions Factors | | | Total Emissions | |
|---|---|---|---|---|---|---|---|---|---|---|
| Equipment | Code | CL = comp. lvl, SL = site lvl | Det AF | Rand AF | AF | Det EF | Rand EF | EF | Sample | Pop. |
| Well | WELL | CL | | | | | | | | |
| Header | HD | CL | | | | | | | | |
| Heater | HE | CL | | | | | | | | |
| Separator | SE | CL | | | | | | | | |
| Meter | ME | CL | | | | | | | | |
| Tanks - Leaks | TAL | CL | | | | | | | | |
| Tanks - Vents | TAV | CL | | | | | | | | |
| Recip Compressor | CR | CL | | | | | | | | |
| Dehydrator | DE | CL | | | | | | | | |
| Chemical Injection Pump | CIP | CL | | | | | | | | |
| Pneumatic Controller | PC | CL | | | | | | | | |
| LU | LU | CL | | | | | | | | |
| Completions | COM | CL | | | | | | | | |
| Workovers | WOR | CL | | | | | | | | |
| Storage tank venting | TK | CL | | | | | | | | |
| Gathering and Boosting | GB | SL | | | | | | | | |
| Processing | PR | SL | | | | | | | | |
| Transmission | TRA | SL | | | | | | | | |
| Distribution | DIS | SL | | | | | | | | |

$$af \cdot EF = Q$$

**Figure S7: Screenshot of the *Calculation table*, with shaded columns highlighting activity factors (*af*), emissions factors (*EF*), and total emissions (*Q*).**

### *3.1.2. Fugitives macro*

The *Fugitives macro* serves several functions in the OPGEE component-level VF tool. First, it allows OPGEE to iterate across wells, and second it executes two conditional statements. These conditional statements are the well sampling (already described above) and a conservation of mass check.

The first conditional statement executed in the *Fugitives macro* is to check if well sampling is required. If $n_{wells} > n_{max}$ for a field (where $n_{max}$ is the maximum number of wells OPGEE will process), then a smaller sample set where $n_{wells} = n_{max}$ is created. The sample sets are tracked in the *Summary table* and before venting and fugitive emissions are passed to other sub-modules, emissions are extrapolated from $n_{max}$ to $n_{wells}$.

The second conditional statement is a conservation of mass (COM) check. At every well, a check is performed to ensure COM is not violated. In the COM check, the summed leaks are compared to total gas production at the well-pad. By applying the COM check we ensure total leakage does not exceed 100% of gas productivity (also accounting for the gathering and boosting, processing, transmission, and distribution sectors). If emissions exceed well-level $CH_4$ production, the macro loops back and iterates again for that well.

The COM check wouldn't be required if quantified emissions measurements from the literature were coupled with information on the gas throughput of the component. However, in contrast to the "site-level" studies synthesized by Omara et al [11], few (if any) "component-level" measurement studies provide information on the gas production volumes of measured wells and well-pad equipment. That is, these studies typically sample and quantify leak volumes from different pieces of equipment. Due to the missing volumetric production data, we only have leak volumes in absolute terms (e.g., scf per hour or kg per day). The application of COM to the iterative draws is what restricts high emitters at low productivity well-pads and is what leads to the "scale dependence" of fractional leakage rates.

### *3.1.3. Format of OPGEE outputs*

Outputs from OPGEE are of the following form:

| | Tranche # [1-74] | OPGEE Column # [200-273] | Fraction sampled [Actual well count /Sample size] | Well productivity [kg/well/day] | Well productivity [scf/well/day] | Emissions array[1] |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| … | | | | | | |
| … | | | | | | |
| $n_{wells}$ | | | | | | |

[1]There are 15 columns and the order is as follows: wellheads, headers, heaters, separators, meters, tank leaks, tank thief hatches/PRVs, reciprocating compressors, chemical injection pumps, pneumatic controllers, liquid unloadings, completions, workovers, intentional tank flashing events

Note that every row here is on a "well-basis" (i.e., one row per well). Also note that there are many "zero" values in the results spreadsheets and this is due to a number of different reasons. First, as we describe in Section 3.4, equipment are randomly assigned to wells on the basis of activity-drivers (number of equipment X per well, for example ~70% of natural gas system wells will be assigned a separator, or ~40% for petroleum systems). Second, based on our equipment-level emission factor distributions there are certain cases where all components on a piece of equipment register no leaks. Therefore, equipment-level emission factor distributions will contain some "zero" values.

## 3.2. Database of component-level studies

The bottom-up approach begins with a database of component-level survey data. We begin this section by describing the criteria for screening component-level data and our correspondence structure for organizing data across various studies with differing definitions. We conclude by summarizing our data for component counts, component-level emission factors, and fraction of components leaking.

### *3.2.1. Summary of criteria for inclusion in our analysis*

We reviewed the literature for field studies with measurement and quantification of emissions data at the component scale. All studies of leakage performed at the wellsite/facility or producing field/region scale were removed from consideration. After confirming the correct scale, the document was included if it contained any of the following information: (i) activity counts for numbers of components per piece of equipment or per site, (ii) data on fraction of components found to be leaking in a survey, or (iii) data on quantified leak volumes per emitting component or source.

Next, because we are only modeling equipment leaks in the production sector, we exclude studies which focus solely on the midstream or downstream sectors. Further, though a number of high quality measurement campaigns have been conducted in Canada (e.g., [12], [13]), in this study we only include U.S.-based datasets in our analysis of U.S. emissions. This is to avoid possible biases in the dataset due to differing regulatory and operating standards between countries. Future work will compare Canadian and US results. All studies passing this final filter are summarized in **Table 2** (Main text).

### *3.2.2. Correspondence of each study into standard classification scheme for equipment and components*

As noted in the main text, component-level activity and emissions rate data are aggregated from various studies. In order to aggregate the data from the various studies, a standardized set of components is required.

First, a 16-fold categorization structure was initially applied in our database:

1. Threaded connections

2. Valve
3. Open-ended line
4. Pressure-relief valve
5. Compressor seal
6. Regulator
7. Flanges
8. Vents
9. Pumps
10. Tank vents
11. Tank thief hatch
12. Tank pressure-relief valve
13. Pneumatic controller/actuator
14. Chemical injection pump
15. Other
16. Not recorded

**Table S4** provides counts and average component-level emission factors across studies for this 16-fold classification scheme.

**Table S4: Quantified measurement count and emissions factor by study according to the 16-fold classification scheme**

| | | Threaded Conns. | Valve | Open-ended line | Pressure-relief valve | Comp. seal | Regulator | Flanges | Vents | Pump | Pneumatic controller/ actuator | Tank vent | Tank hatch/ hole | Tank PRV | Chemical Injection Pump | Other | Not recorded |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | TC | VL | OEL | PRV | CS | REG | F | VT | PM | PC | TV | TH | TP | CIP | OTH | NR |
| API 1993 | | | | | | | | | | | | | | | | | |
| Counts | 500 - 10000 ppmv | 9 | 16 | 16 | 5 | 1 | - | - | 0 | - | - | - | - | - | - | 2 | - |
| | > 10000 ppmv | 29 | 97 | 38 | 5 | 1 | - | - | 4 | - | - | - | - | - | - | 28 | - |
| | All | 38 | 113 | 54 | 10 | 2 | - | - | 4 | - | - | - | - | - | - | 30 | - |
| Emissions factors [kg/d] | 500 - 10000 ppmv | 0.02 | 0.02 | 0.01 | 0.00 | 0.02 | - | - | - | - | - | - | - | - | - | 0.01 | - |
| | > 10000 ppmv | 0.30 | 0.44 | 0.16 | 1.70 | 0.77 | - | - | 0.22 | - | - | - | - | - | - | 0.35 | - |
| | All | 0.23 | 0.38 | 0.12 | 0.85 | 0.40 | - | - | 0.22 | - | - | - | - | - | - | 0.32 | - |
| Allen 2013 | | | | | | | | | | | | | | | | | |
| Counts | 500 - 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | > 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | All | 44 | 41 | 5 | 3 | - | 51 | 6 | 53 | - | 305 | 124 | - | - | 62 | 74 | - |
| Emissions factors [kg/d] | 500 - 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | > 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | All | 1.22 | 2.59 | 0.76 | 2.84 | - | 1.35 | 1.22 | 8.65 | - | 4.84 | 3.52 | - | - | 5.31 | 1.58 | - |
| Allen 2014a | | | | | | | | | | | | | | | | | |
| Counts | 500 - 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | > 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | All | - | - | - | - | - | - | - | - | - | 377 | - | - | - | - | - | - |
| Emissions factors [kg/d] | 500 - 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | > 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | All | - | - | - | - | - | - | - | - | - | 2.26 | - | - | - | - | - | - |
| Bell 2017 | | | | | | | | | | | | | | | | | |
| Counts | 500 - 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | > 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | All | 18 | 9 | - | 14 | - | 18 | 3 | 3 | - | 41 | 35 | - | - | 3 | 82 | 20 |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Emissions factors [kg/d] | 500 - 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | > 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | All | 2.71 | 1.00 | - | 2.57 | - | 6.08 | 2.49 | 5.61 | - | 2.45 | 23.84 | - | - | 0.23 | 4.03 | 1.95 |
| | | | | | | | | ERG 2011 | | | | | | | | | |
| Counts | 500 - 10000 ppmv | 139 | 45 | 0 | - | - | 20 | 3 | 4 | - | 1 | 1 | 46 | 1 | 0 | 55 | 11 |
| | > 10000 ppmv | 339 | 94 | 13 | - | - | 75 | 0 | 57 | - | 6 | 33 | 219 | 40 | 1 | 708 | 37 |
| | All | 478 | 139 | 13 | - | - | 95 | 3 | 61 | - | 7 | 34 | 265 | 41 | 1 | 763 | 48 |
| Emissions factors [kg/d] | 500 - 10000 ppmv | 0.74 | 3.33 | - | - | - | 2.18 | 0.13 | 0.01 | - | 0.05 | 0.13 | 2.92 | 0.09 | - | 3.33 | 0.01 |
| | > 10000 ppmv | 4.15 | 14.85 | 9.73 | - | - | 6.50 | - | 9.90 | - | 16.57 | 44.19 | 51.80 | 60.30 | 127.87 | 15.01 | 0.18 |
| | All | 3.16 | 11.12 | 9.73 | - | - | 5.59 | 0.13 | 9.25 | - | 14.21 | 42.89 | 43.31 | 58.83 | 127.87 | 11.20 | 0.14 |
| | | | | | | | | Thoma 2017 | | | | | | | | | |
| Counts | 500 - 10000 ppmv | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | > 10000 ppmv | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80 | 0 | 0 | 0 | 0 | 0 | 0 |
| | All | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 80 | 0 | 0 | 0 | 0 | 0 | 0 |
| Emissions factors [kg/d] | 500 - 10000 ppmv | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | > 10000 ppmv | - | - | - | - | - | - | - | - | - | 0.15 | - | - | - | - | - | - |
| | All | - | - | - | - | - | - | - | - | - | 0.15 | - | - | - | - | - | - |
| | | | | | | | | Pacsi 2019 | | | | | | | | | |
| Counts | 500 - 10000 ppmv | 69 | 14 | 5 | 1 | - | 9 | 1 | 0 | - | - | - | - | - | - | 6 | - |
| | > 10000 ppmv | 44 | 18 | 2 | 2 | - | 9 | 2 | 1 | - | - | - | - | - | - | 9 | - |
| | All | 113 | 32 | 7 | 3 | - | 18 | 3 | 1 | - | - | - | - | - | - | 15 | - |
| Emissions factors [kg/d] | 500 - 10000 ppmv | 0.59 | 1.58 | 3.56 | 0.94 | - | 0.24 | 0.07 | - | - | - | - | - | - | - | 0.28 | - |
| | > 10000 ppmv | 1.78 | 2.97 | 0.09 | 0.21 | - | 1.20 | 1.06 | 14.39 | - | - | - | - | - | - | 0.96 | - |
| | All | 1.05 | 2.36 | 2.57 | 0.46 | - | 0.72 | 0.73 | 14.39 | - | - | - | - | - | - | 0.69 | - |

Modifications were made to this 16-fold categorization structure prior to consolidating measurements for the bootstrapping exercise: (i) Connectors and flanges were combined into a single category, and (ii) the categories “pump”, “vent”, and “not recorded” were removed due to lack of activity data. Regarding vents specifically, we should note that many emissions classified as vents (e.g., pneumatic instruments, storage tanks open to the atmosphere, liquids unloading) have been already included explicitly in other categories. Although some have not (e.g., glycol dehydrator off-gassing, equipment blowdowns) by not including the generic category “vents” we avoid potential double counting. Similarly, it is unclear if the generic label “pump” is in reference to chemical injection pumps.

With these adjustments, our proposed component structure is therefore a 12-fold categorization scheme. Thus, all components from all studies will be grouped into 11 categories and “other” as follows:

1. Threaded connections and flanges
2. Valve
3. Open-ended line
4. Pressure-relief valve
5. Compressor seal
6. Regulator
7. Pneumatic controller/actuator
8. Chemical injection pump
9. Tank vents
10. Tank thief hatch or exterior hole
11. Tank pressure-relief valve
12. Other

We generated the 12-fold categorization scheme by examining the frequency of data reporting and common levels of data granularity across the studies. The range of details provided varies by study, so using too fine or too coarse of a classification scheme would be sub-optimal. If too fine of a classification scheme is used, data become challenging to use from studies where only coarse categorization is reported. If too coarse of a classification scheme is used, large amounts of possibly useful identifying information are lost.

Note that although “compressor seal” is included in this list, it is not included in emissions factor summary tables. This is because although compressor seals are included in numerous studies in our (unfiltered, including non-USA and midstream/downstream measurements) database and in activity factor matrices (component counts per equipment), in our final, filtered emissions dataset no emissions measurements existed for compressor seals.

There is always a tradeoff in the generality vs the simplicity of a naming scheme. A simple naming scheme is easier to record data into, and perhaps more generalizable between studies. However, a simple naming scheme removes nuance (e.g., what kind of compressor seal is used?). We believe that the above 12-fold level of aggregation strikes the correct balance and allows most datasets in the literature to be used.

A standardized structure was also required for equipment categories. We generate a proposed 11-fold categorization scheme is as follows:

1. Well
2. Header
3. Heater
4. Separator
5. Meter
6. Tanks – leaks
7. Tanks – Vents
8. Compressor – Reciprocating
9. Dehydrator
10. Chemical Injection Pump
11. Pneumatic Controller/Actuator

Because Tanks are an important emissions source, two separate equipment bins were created for tanks. The “Tanks – leaks” category tracks all non-vent/hatch emissions on a tank (e.g., connectors, valves, etc.) while the “Tank – vent” category contains “Tank vents”, “Tank thief hatch or exterior hole”, and “Tank pressure-relief valve” component categories.

Additional technical details on the use of correspondence matrices is provided in section 3.2.5.

### *3.2.3. Component counts*

Data on component counts are relatively sparse and are sourced in this study from the American Petroleum Institute [4], Pacsi et al [14], and Clearstone [13]. Note that we make an exception to our filters here and apply Canadian data from the Clearstone study due to the severe data limitations inherent in only including 2 U.S. studies.

Note that there is a high degree of uncertainty in our assumptions regarding counts of thief hatches, pressure-relief valves, and open vents at tanks. Here we assume one thief hatch and PRV per tank (see discussion in SI-3.3.2), and zero vents as these are already accounted for with purposeful venting. See also SI-4.4.2, where we adjust the "fraction of components emitting" variable downwards for the pressure-relief valves to account for the possibility of overlap or double counting between PRVs and purposeful venting.

Similarly to the handling of quantified leakage data, we transform the study component counts into our standardized classification scheme by using correspondence matrices (**Table S5** and **Table S6**). Component counts are classified for oil and gas systems using naming conventions in studies (e.g., API and Clearstone classify oil and gas systems separately, while Pacsi et al [14] provide aggregate component counts).

**Table S5: Component counts for NG equipment describing the total range of values found in the literature (lower bound – upper bound)**

| | Threaded connections/ flange | Valve | Open-ended line | Pressure-relief valve | Compressor seal | Regulator | Pneumatic controller | Chemical Inj Pump | Tank - hatch/hole | Tank-PRV | Tank-vent | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well | 74-298 | 13-27 | 1-5 | 1-4 | 0 | 1-1 | 0 | 0 | 0 | 0 | 0 | 1-1 |
| Heater | 20-177 | 2-29 | 1-5 | 1-2 | 1-1 | 2-4 | 0 | 0 | 0 | 0 | 0 | 1-1 |
| Separator | 62-125 | 12-28 | 1-1 | 1-2 | 0 | 3-3 | 0 | 0 | 0 | 0 | 0 | 2-2 |
| Meter | 39-100 | 3-19 | 1-2 | 1-2 | 0 | 2-2 | 0 | 0 | 0 | 0 | 0 | 2-2 |
| Tank | 3-179 | 1-31 | 1-9 | 1-14 | 2-2 | 1-1 | 0 | 0 | 1 | 1 | 0 | 0 |
| Compressor – Reciprocating | 120-586 | 18-35 | 1-4 | 1-4 | 4-4 | 1-6 | 0 | 0 | 0 | 0 | 0 | 1-1 |
| Dehydrator | 27-217 | 6-29 | 1-1 | 1-3 | 0-0 | 6-6 | 0 | 0 | 0 | 0 | 0 | 2-2 |
| Chemical Inj. Pump | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1-1 | 0 | 0 | 0 | 0 |
| Pneum. Cont. | 0 | 0 | 0 | 0 | 0 | 0 | 1-1 | 0 | 0 | 0 | 0 | 0 |

**Table S6: Component counts for petroleum equipment describing the total range of values found in the literature (lower bound – upper bound)**

| | Threaded connections/ flange | Valve | Open-ended line | Pressure-relief valve | Compressor seal | Regulator | Pneumatic controller | Chemical Inj Pump | Tank - hatch/hole | Tank-PRV | Tank-vent | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well | 61-298 | 7-23 | 1-3 | 1-4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Header | 23-520 | 2-143 | 1-4 | 1-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1-1 |
| Separator | 62-139 | 11-28 | 2-3 | 1-1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1-1 |
| Tank | 6-76 | 2-15 | 1-3 | 1-1 | 1-1 | 1-1 | 0 | 0 | 1 | 1 | 0 | 0 |
| Chemical Inj. Pump | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1-1 | 0 | 0 | 0 | 0 |
| Pneum. Cont. | 0 | 0 | 0 | 0 | 0 | 0 | 1-1 | 0 | 0 | 0 | 0 | 0 |

### *3.2.4. Component level emissions factors and fraction of components emitting*

Due to differences in the detection threshold of screening technologies used in field campaigns, different studies will sample different parts of the "true" population emissions distribution. In addition to differences in screening, not all studies perform a full and comprehensive component count and survey across all well sites. Therefore, care must be taken in combining studies into a singular database to ensure that (i) certain parts of the distribution are not over or under-represented in our dataset, and that (ii) fraction of components emitting (the ratio of leaking components to all components counted) is consistent with our dataset's emissions distribution. To ensure that we are not "over or under-sampling" a subset of the true distribution, we separated our dataset at 10,000 ppmv. Fraction of components emitting is calculated independently for the two sub-populations.

For example, if the fraction of components emitting is defined as "fraction of emitting component X" divided by "total count of component X surveyed" we must be careful how we define a "leaker". The definition of "leaker" is different depending on which screening technology was used. The EPA Method 21 procedure involves screening components with a toxic vapor analyzer, a hydrocarbon detection probe with a range extending from approximately 0.5-50,000 ppmv. Optical gas imaging (OGI) is an EPA approved alternative to Method 21 which involves viewing components from a distance with an infrared camera. OGI is less labor intensive compared to Method 21 but is also less precise (detection floor approximately 10,000 ppmv). For example, in the API 4598 [3] dataset, which applied Method 21, leaks as low as 10 ppmv are included, whereas in Allen et al [15] surveying is done using only an OGI camera, which is very unlikely to see a leak resulting in 10 ppm local enhancement.

Method 21 screening values (in concentration, ppmv) offer a means of ensuring consistency across sampled emissions measurements and fraction of components emitting. Further, for all studies that provide sufficient data to quantify fraction of components emitting, concentration data are available. Given that 10,000 ppmv is the concentration requirement for OGI devices in Subpart OOOOa [16], we choose this as a cutoff for measurement data and fraction of components emitting. We note, however, that this is somewhat imprecise given that the threshold for detecting an emitter with an infrared camera is not fixed at an inherent threshold of 10,000 ppmv but also depends on operator experience and site-specific variables such visual background

and wind speeds. Although OGI is operationally less precise than Method 21, we expect the leakage distribution to be more balanced above 10,000 ppmv.

Our dataset is split as follows:

(i) *Dataset ≥ 10,000 ppmv*: This set includes data with Method 21 measurements ≥ 10,000 ppmv (API 4598 [3], ERG [17], Pacsi et al. [14]) but also primarily OGI-based measurement campaigns (Allen et al. [15], Bell et al. [18]). We note that this classification isn't perfect given that Bell et al. [18] also used a TVA (toxic vapor analyzer) and therefore their data will include some measured emitters > 500 ppmv and < 10,000 ppmv. However, we could not differentiate these emitters given that no concentration values were provided along with each emitter determination.

(ii) *Dataset 500-10,000 ppmv*: For this set, we were only able to include portions of datasets based on studies that provided M21 concentration measurements (API 4598 [3], ERG [17], Pacsi et al. [14]). We note that 5 measurements in ERG labelled "M21&OGI" which registered < 500 ppmv are included in this set. However, this may have been a mistake given that ERG notes only measurements screening >500 ppmv were sampled with the High Flow sampler.

**Table S7** and **Table S8** contain summary statistics for our dataset by component and by study, respectively. Note that the measurement counts in **Table S7** (n = 3247) don't add up directly to the measurement counts in **Table S8** (n = 3441) given that 194 measurements did not have component labels.

**Table S7: Consolidated component-level emission factors according to our 12-fold classification and disaggregated according to ≥10,000 ppmv and < 10,000 ppmv screening measurements**

| Component | N [samples] | Minimum [kg CH4/d] | Maximum [kg CH4/d] | Mean [kg CH4/d] | Median [kg CH4/d] | Contr of SE [top 5%] |
|---|---|---|---|---|---|---|
| >10,000 ppmv | | | | | | |
| Comp. Seal | 1 | 7.71E-01 | 0.77 | 0.77 | 0.77 | 100% |
| OEL | 58 | 0.00E+00 | 60.71 | 2.36 | 0.04 | 72% |
| Other | 901 | 0.00E+00 | 439.82 | 11.64 | 3.32 | 72% |
| Pneu. controller | 809 | 0.00E+00 | 66.15 | 3.14 | 0.30 | 47% |
| PRV | 24 | 0.00E+00 | 12.20 | 2.23 | 0.55 | 45% |
| Regulator | 153 | 0.00E+00 | 79.64 | 4.42 | 1.35 | 42% |
| Connectors | 485 | 0.00E+00 | 210.86 | 3.33 | 0.26 | 62% |
| Valve | 259 | 0.00E+00 | 708.65 | 6.20 | 0.26 | 68% |
| Chemical inj. pumps | 66 | 5.70E-02 | 127.87 | 6.94 | 1.35 | 53% |
| Tank hatch/hole | 219 | 0.00E+00 | 510.51 | 51.80 | 21.34 | 36% |
| Tank PRV | 40 | 1.30E-01 | 351.53 | 60.30 | 20.59 | 24% |
| Tank vent | 68 | 4.89E-02 | 288.65 | 33.71 | 11.88 | 36% |
| All | 3082 | 0.00E+00 | 708.65 | 10.91 | 1.23 | 57% |
| 500 - 10,000 ppmv | | | | | | |
| Comp. Seal | 1 | 2.23E-02 | 0.02 | 0.02 | 0.02 | 100% |
| OEL | 21 | 0.00E+00 | 17.75 | 0.85 | 0.00 | 99% |
| Other | 63 | 0.00E+00 | 14.48 | 0.47 | 0.01 | 99% |
| Pneu. controller | 1 | 5.06E-02 | 0.05 | 0.05 | 0.05 | 100% |
| PRV | 6 | 0.00E+00 | 0.94 | 0.16 | 0.00 | 99% |
| Regulator | 29 | 2.49E-03 | 16.50 | 1.57 | 0.01 | 68% |
| Connectors | 221 | 0.00E+00 | 60.48 | 0.65 | 0.01 | 88% |
| Valve | 75 | 0.00E+00 | 126.72 | 2.29 | 0.01 | 96% |
| Chemical inj. pumps | 1 | 0.00E+00 | 0.00 | 0.00 | 0.00 | 0% |
| Tank hatch/hole | 46 | 0.00E+00 | 36.49 | 2.92 | 0.71 | 55% |
| Tank PRV | 1 | 9.32E-02 | 0.09 | 0.09 | 0.09 | 100% |
| Tank vent | 1 | 1.30E-01 | 0.13 | 0.13 | 0.13 | 100% |
| All | 464 | 0.00E+00 | 126.72 | 1.17 | 0.01 | 84% |

**Table S8: Consolidated component-level emission factors according to study and disaggregated according to ≥10,000 ppmv and < 10,000 ppmv screening measurements**

| Study | N [samples] | Minimum [kg CH4/d] | Maximum [kg CH4/d] | Mean [kg CH4/d] | Median [kg CH4/d] | Contr of SE [top 5%] |
|---|---|---|---|---|---|---|
| >10,000 ppmv | | | | | | |
| API1993 | 202 | 0.000 | 8.77 | 0.38 | 0.00 | 74% |
| Allen2013 | 645 | 0.000 | 132.97 | 4.08 | 1.24 | 42% |
| Allen2014a | 377 | 0.000 | 66.15 | 2.26 | 0.00 | 58% |
| Bell2017 | 246 | 0.049 | 212.14 | 6.23 | 1.11 | 63% |
| ERG2011 | 1623 | 0.000 | 708.65 | 18.15 | 4.02 | 50% |
| Thoma 2017 | 80 | 0.039 | 1.99 | 0.15 | 0.04 | 47% |
| Pasci 2019 | 87 | 0.007 | 32.57 | 1.93 | 0.25 | 54% |
| 500-10,000 ppmv | | | | | | |
| API 1993 | 49 | 0.000 | 0.10 | 0.01 | 0.00 | 42% |
| Allen2013 | 1 | 0.000 | 0.00 | 0.00 | 0.00 | 0% |
| Allen2014a | 1 | 0.000 | 0.00 | 0.00 | 0.00 | 0% |
| Bell2017 | 1 | 0.000 | 0.00 | 0.00 | 0.00 | 0% |
| ERG2011 | 326 | 0.000 | 126.72 | 1.41 | 0.01 | 85% |
| Thoma 2017 | 1 | 0.000 | 0.00 | 0.00 | 0.00 | 0% |
| Pasci 2019 | 105 | 0.002 | 17.75 | 0.81 | 0.08 | 75% |

Next, values for fraction of components emitting were estimated as follows (**Table S9**).

- For all studies which provide both comprehensive component counts and concentration ppmv) screening data (API 4598 [3], ERG [17], Pacsi et al. [14]), counts of screening measurements were used to estimate fraction of components emitting.
- ERG note that only one in ten components were screened using Method 21. Therefore, in calculating fraction of components emitting, the emitter count < 10,000 ppmv was multiplied by ten.
- None of these studies accounted for regulators, therefore a fraction of components emitting value for regulators was taken from a Canadian study by Clearstone [13].

It should be noted that the approach of how to handle fraction of components emitting is different for pneumatic controllers (primary data source Allen et al. [8]) versus other components derived from various studies. In Allen et al., all pneumatic controllers were measured, versus other studies where only emitting components were quantified. For pneumatic controllers, the

fraction of components emitting value we apply is equivalent to the fraction of wells in the US (75%) which have pneumatic controllers (vs. non-pneumatic, non-emitting controllers).

**Table S9: Review of studies surveyed in developing fraction of components emitting values**

| | Threaded connections/ flange | Valve | Open-ended line | Pressure-relief valve | Compressor seal | Regulator | Pneumatic controller | Chemical Inj Pump | Tank - hatch/hole | Tank-PRV | Tank-vent | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | API 1993 | | | | | | |
| Component counts | 81,659 | 17,649 | 2,187 | 420 | 62 | - | - | 33 | - | - | - | 670 |
| Emitter Count | | | | | | | | | | | | |
| 500 - 10,000 ppmv | 566 | 440 | 55 | 13 | 2 | - | - | 1 | - | - | - | 102 |
| > 10,000 ppmv | 237 | 247 | 29 | 1 | 4 | - | - | - | - | - | - | 41 |
| Fraction emitting | | | | | | | | | | | | |
| 500 - 10,000 ppmv | 0.69% | 2.49% | 2.51% | 3.10% | 3.23% | - | - | 3.03% | - | - | - | 15.22% |
| > 10,000 ppmv | 0.29% | 1.40% | 1.33% | 0.24% | 6.45% | - | - | 0.00% | - | - | - | 6.12% |
| | | | | | | ERG 2011 | | | | | | |
| Component counts | 603,026 | 80,465 | - | - | - | - | - | - | 1,163 | 1,163 | 1,163 | - |
| Emitter Count | | | | | | | | | | | | |
| 500 - 10,000 ppmv | 1,390 | 450 | - | - | - | - | - | - | 480 | 20 | 10 | - |
| > 10,000 ppmv | 339 | 94 | - | - | - | - | - | - | 292 | 73 | 33 | - |
| Fraction emitting | | | | | | | | | | | | |
| 500 - 10,000 ppmv | 0.23% | 0.56% | - | - | - | - | - | - | 39.55% | 0.86% | 0.86% | - |
| > 10,000 ppmv | 0.06% | 0.12% | - | - | - | - | - | - | 18.83% | 3.44% | 2.84% | - |
| | | | | | | Pacsi 2019 | | | | | | |
| Component counts | 46,442 | 7,396 | 414 | 366 | - | - | - | - | - | - | - | - |
| Emitter Count | | | | | | | | | | | | |
| 500 - 10,000 ppmv | 70 | 14 | 5 | 1 | - | - | - | - | - | - | - | - |
| > 10,000 ppmv | 46 | 18 | 2 | 2 | - | - | - | - | - | - | - | - |
| Fraction emitting | | | | | | | | | | | | |
| 500 - 10,000 ppmv | 0.15% | 0.19% | 1.21% | 0.27% | - | - | - | - | - | - | - | - |
| > 10,000 ppmv | 0.10% | 0.24% | 0.48% | 0.55% | - | - | - | - | - | - | - | - |

**Table S10: Lower and upper limits of uniform distribution of fraction of components emitting applied in Monte Carlo uncertainty analysis**

| | Threaded connections/ flange | Valve | Open-ended line | Pressure-relief valve | Compressor seal | Regulator | Pneumatic controller | Chemical Inj Pump | Tank - hatch/hole | Tank-PRV | Tank-vent | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| > 10,000 ppmv | | | | | | | | | | | | |
| Lower bound | 0.06% | 0.12% | 0.48% | 0.24% | 6.45% | 0.88% | 75.00% | 0.00% | 18.83% | 0.00% | 0.00% | 6.12% |
| Upper bound | 0.29% | 1.40% | 1.33% | 0.55% | 6.45% | 0.88% | 75.00% | 0.00% | 18.83% | 3.44% | 2.84% | 6.12% |
| 500-10,000 ppmv | | | | | | | | | | | | |
| Lower bound | 0.15% | 0.19% | 1.21% | 0.27% | 3.23% | 0.88% | 75.00% | 3.03% | 39.55% | 0.00% | 0.00% | 15.22% |
| Upper bound | 0.69% | 2.49% | 2.51% | 3.10% | 3.23% | 0.88% | 75.00% | 3.03% | 39.55% | 0.86% | 0.86% | 15.22% |

### *3.2.5. Additional information on correspondence matrices*

For each study we need to align the categories of components used by the authors of a study to our common component definitions that can be used across all studies. In order to do this we create a "correspondence matrix" **P** that converts the original data categorization scheme into the new data categorization. This correspondence matrix is composed using the following procedure:

Assume that we have a component count matrix **C** for a set of *m* equipment types and *n* component types, organized as follows for a given study:

| | Component 1 | Component 2 | … | Component n |
|---|---|---|---|---|
| Equipment 1 | $c_{11}$ | $c_{12}$ | … | $c_{1n}$ |
| Equipment 2 | $c_{21}$ | $c_{22}$ | … | $c_{2n}$ |
| … | … | … | … | … |
| Equipment m | $c_{m1}$ | $c_{m2}$ | … | $c_{mn}$ |

For a given equipment type *i* ($i \in 1 \ldots m$) and component type *j* ($j \in 1 \ldots n$), the value of $c_{ij}$ is the number of components of that type present in that equipment type.

However, each set of equipment and component types can vary between studies. That is, the values of *m* and *n* can differ (i.e., how many types of equipment or how many types of components) between studies. Also, the names of components and equipment can differ, as can their order of presentation between studies.

Given any given component count matrix **C** in the form presented for a given study, we can create a standardization matrix **P** that will permute and change the shape of C such that it has the same set of components in a standard list of components $\mathbf{c}^* = [c_1^*, c_2^*, c_3^* \ldots c_n^*]$. We define the matrix P as follows:

- An entry of **P** at location $p_{ij} = 1$ if component type i in the study dataset should be included as part of component type j in the standardized component list
- An entry of **P** at location $p_{ij} = 0$ if component type i in the study dataset should not be included as part of component type j in the standardized component list

We show a hypothetical example below. In this example, the hypothetical study dataset has two types of compressors -- reciprocating compressors and centrifugal compressors. The study also contains four possible types of components at each compressor: (1) centrifugal compressor seals, (2) reciprocating compressor seals, (3) threaded connections, and (4) flanges. However, in our standardized component set, we want to group compressor seals all together in a group called "CS" and also group threaded connections and flanges into a category called "connectors". If we have the following raw data **C** from the study:

| | Centr. CS | Recip. CS | Threaded connectors | Flanges |
|---|---|---|---|---|
| Centrifugal compressor | 6 | 0 | 6 | 7 |
| Reciprocating compressor | 0 | 7 | 37 | 14 |

We can create a standardization matrix **P** as follows:

| | CS | Connectors |
|---|---|---|
| Centr. CS | 1 | 0 |
| Recip. CS | 1 | 0 |
| Threaded connectors | 0 | 1 |
| Flanges | 0 | 1 |

Note that the standardization matrix has dimension related to the dataset of interest: our starting set of components in the rows and our desired set of components is in the columns. We can then create a new dataset **F** with the component counts presented for each type:

**F** = **C** x **P**

Or, in our example, **F** is equal to:

| | **CS** | **Connectors** |
|---|---|---|
| **Centrifugal compressor** | 6 | 13 |
| **Reciprocating compressor** | 7 | 51 |

The benefit of this approach is that the correspondence between the original data set and the final dataset is uniquely defined by **P**. We do not reproduce the correspondence matrices **P** here, but they are available in the Github database.

## 3.3. Development of equipment-level emission factors

### *3.3.1. The "stochastic failure" approach*

The "stochastic failure" approach is used to estimate emissions from: all equipment-level fugitive emissions, compressor vents, pneumatic controller vents, dehydrator vents, and abnormal process vents from tanks. In the stochastic failure approach, a sample of component-level measurements are iteratively re-sampled (bootstrapped) to generate a distribution of equipment-level emission factors. Here, we will briefly explain the development of equipment level emissions factor distributions.

To begin, we recall that our dataset has been split at a threshold of 10,000 ppmv (describing leaks that were missed by optical gas imaging but caught with Method 21 below the threshold, and leaks that were caught with optical gas imaging above the threshold, see Section 3.2.4). We have defined this split to (to the best of our ability) describe two distinct and mutually exclusive parts of the leaker distribution. Assuming this is true, the complete distribution can be defined as the superposition of the two halves.

$$EF = EF_{< 10{,}000\ \text{ppmv}} + EF_{\geq 10{,}000\ \text{ppmv}}$$

Each of these distributions is developed separately as follows. In iterative loops, the algorithm sweeps across all equipment ($n_E$), all components ($n_C$), and all components per equipment (CQ). The number of components leaking per piece of equipment (LQ) is tallied according to a random draw and the estimated component-specific fraction leaking (FL). This process is repeated 10,000 times ($n_{trials}$ = 10,000)

$$LQ_{i,j,k} = \sum_{l=1}^{CQ_{i,j,k}} X_{i,j,k,l} \quad \forall\, i\epsilon\{1,\dots,n_{trials}\}, j\epsilon\{1,\dots,n_e\}, k\epsilon\{1,\dots,n_c\}$$

Here LQ is a 3-dimensional matrix, with dimensions 10,000 x $n_E$ x $n_c$. During the iteration across each component class, X is a random binary variable set equal to 1 if a uniformly distributed random number ($p$) on [0,1] is drawn that is greater than FL for that component type. Put

differently, for each leak draw *l*, if the random number drawn is less than the probability of leakage then $LQ_{ijk}$ is incremented by 1.

$$X_{i,j,k,l} = \begin{cases} 1 & p \leq FL \\ 0 & p > FL \end{cases}$$

The resulting matrix $LQ_{ijk}$ is the number of leaks for each component type *k* in each equipment type *j*, for each realization *i* (of which there are 10,000).

Next, the algorithm assigns leakage volumes to these leaks. Based upon the number of leaks in LQ, a corresponding number of leaks of the correct component type are randomly drawn from the database of CF (with replacement). This process is repeated 10,000 times producing a second 3-dimensional matrix with dimensions 10,000 x $n_E$ x $n_c$

$$EF_{i,j,k} = \sum_{l=1}^{LQ_{i,j,k}} \text{CF} \quad \forall\, i\epsilon\{1,\dots,n_{trials}\}, j\epsilon\{1,\dots,n_e\}, k\epsilon\{1,\dots,n_c\}$$

The matrix EF is then reduced to 2 dimensions by summing across components, or summing across index *k*. This results in a new matrix $EF_{i,j}$ with values of emissions for 10000 trials (index *i*) and $n_e$ equipment types (index *j*). The Matlab tool "prctile" is used to produce probability distributions of emissions per piece of equipment using this matrix.

After superposing the separate equipment-level distributions for < 10,000 ppmv measurements and ≥ 10,000 ppmv measurements, the resulting distributions are embedded in OPGEE's fugitive emissions calculator as a 0 - 100 percentile table for each equipment type *j* in 1…$n_e$. Because we have separate component counts for gas and oil systems, we also have separate equipment level emissions factor distributions (**Table S11**).

It should be noted that the emissions-factor distributions in **Table S11** (*a priori* distributions) are different from the emissions factor distributions presented earlier in **Table S2** and **Table S3** (*post-hoc* distributions). The distributions presented below are eventually applied to OPGEE's venting and fugitive emissions algorithm (Section 3.1), where OPGEE iteratively assigns *a priori* emissions-factors. However, due to the conservation of mass checks, some emissions factor draws are not assigned. *Post hoc* emissions-factors are calculated according to the actual emissions randomly assigned by OPGEE's iterative bootstrapping algorithm. Based on the

OPGEE conservation of mass check, *post-hoc* emissions factors are lower than the average *a priori* emissions-factors. This also results in marginal wells emissions-factors much lower than non-marginal wells emissions factors.

**Table S11: Averages of *a priori* equipment level emissions factor distributions [kg/day]**

| | Natural gas systems | | | Petroleum systems | | |
|---|---|---|---|---|---|---|
| | Mean | 500-10,000 ppmv | > 10,000 ppmv | Mean | 500-10,000 ppmv | > 10,000 ppmv |
| Well heads | 4.7 | 1.5 | 3.3 | 3.3 | 1.0 | 2.2 |
| Header | 4.1 | 1.3 | 2.8 | 9.3 | 3.2 | 6.0 |
| Heater | 3.6 | 1.0 | 2.5 | 2.6 | 0.9 | 1.7 |
| Separator | 4.6 | 1.3 | 3.3 | 3.8 | 1.1 | 2.7 |
| Meter | 3.7 | 0.8 | 2.8 | 2.5 | 0.6 | 1.9 |
| Tanks - Leaks | 2.9 | 1.0 | 1.9 | 1.7 | 0.5 | 1.2 |
| Tanks - Vents | 12.2 | 1.2 | 11.1 | 12.1 | 1.2 | 10.9 |
| Compressor - Recip | 6.9 | 2.1 | 4.8 | 2.5 | 0.8 | 1.7 |
| Dehydrator | 4.7 | 1.2 | 3.5 | 2.0 | 0.6 | 1.4 |
| Chemical Injection Pump | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Pneumatic Controller | 2.4 | 0.0 | 2.4 | 2.4 | 0.0 | 2.4 |

### *3.3.2. Modelling tank emissions*

In our discussion of tank emissions modelling we will differentiate between tank emissions sources and tank emissions mechanisms. Emissions sources from oil and condensate storage tanks are classified as follows and represented graphically in **Figure S8**. For useful pictures and descriptions of components, see also [19].

- *Open vents (e.g., gooseneck open vent, mushroom open vent)*
- *Thief hatch*: The thief hatch is a sort of access door which allows maintenance access to the tank for sampling and gauging. The thief hatch also works in tandem with pressure-relief valves to maintain safe pressures in the tank.
- *Pressure-relief valve*: Whereas an open vent remains in a fixed position, a pressure-relief valve remains closed unless the pressure or vacuum in the tank increases to a set level at which the pressure-relief opens.
- *Other miscellaneous components*: Like other equipment, storage tanks are an assemblage of smaller components. Leaks are tracked and quantified on tanks like any other piece of equipment.

Note that a similar classification scheme is applied in aggregating emissions data for our database (see SI-3.2.2). Also, we assume that each tank contains 1 thief hatch and 1 pressure-relief valve which contribute to emissions at the tank (see **Table S5** and **Table S6,** emissions from the open vent are accounted for in the purposeful venting, or "flash emissions" category). There is a high level of uncertainty in this activity count assumption, given a lack of publicly available component counts (Zimmerle et al. [20] also assume 1 thief hatch and 1 pressure-relief valve per tank, although this is not based on direct counts).

Mechanisms are the processes by which these emissions occur:

- *Flashing emissions*: Emissions resulting from the release of entrained gas in depressurized hydrocarbons from separators.
- *Stuck dump valve resulting in anomalous emissions magnitude*: There are situations where free gas within separators may be released from tanks (see elaboration in the main text). This could be the result of stuck dump valves (due to erosion of seals or solids preventing the valve from closing) or free gas still entrained within the oil or condensate.

Emissions from storage tanks are treated differently depending on whether they are equipped with emissions controls (e.g., flares, combustors, or vapor recovery units). For tanks equipped with controls, flashing emissions are destroyed or captured. US EPA NSPS subpart OOOO requires all tanks (as of April 2013) to install control devices such as flares or vapor recovery units designed to reduce volatile organic compound emissions by at least 95%. However, according to EPA GHGRP 2015 data [21] only 44% of tanks were controlled.

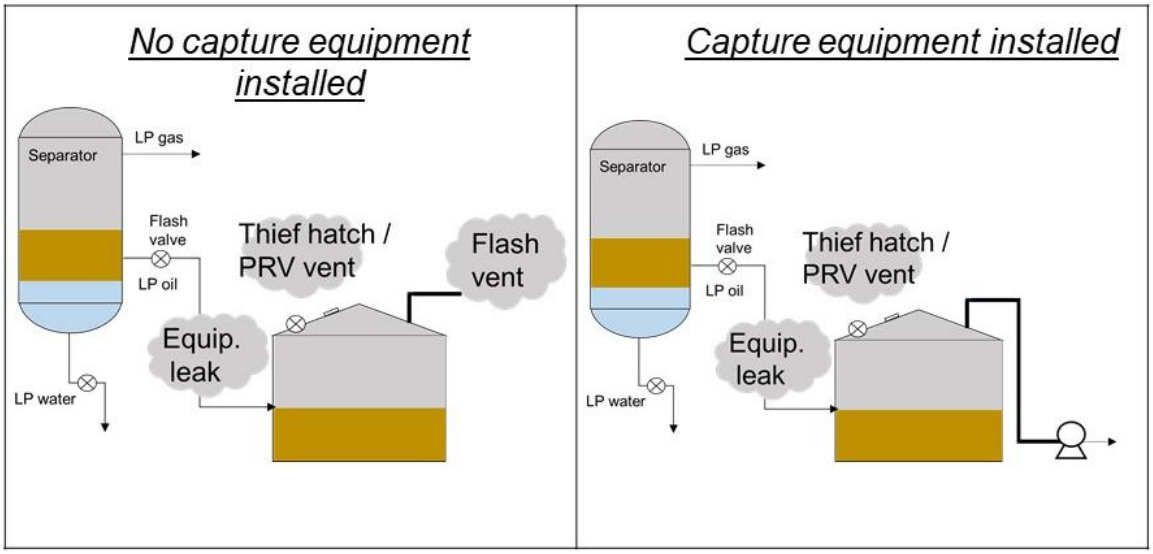


**Figure S8: Illustrative comparison of tank emissions classes for (left) tanks with control devices installed and (right) tanks with no control devices installed.**

Methods for estimating the various emissions sources are outlined as follows:

- *Flash emissions*: we follow generally the methods outlined by Zavala Araiza et al. [22]. Briefly, flash emissions are categorized as either continuous or intermittent based upon the maximum rate of dumping from separators (we use the estimate of 140 bbl/day from Zavala Araiza et al). Tanks receiving crude or condensate at a rate greater than the threshold are assumed to dump continuously, the rest are assumed to dump intermittently. For intermittent dumping, the fraction of tanks receiving dumped liquid at any given moment are assumed to be equal to the ratio of crude and condensate production and the 140 bbl/day threshold. Like Zavala Araiza et al. , the flash emission rate (*FF*, $kgCH_4$/bbl) is based upon the so-called "HARC study" [23], a direct measurement campaign of vent gas emissions from 33 tanks in the Barnett shale intended to reflect "tank working, breathing, and flashing losses". The flash emission rate, *FF*, is converted to an emission factor ($kgCH_4$/tank/day) using the following piecewise formula, depending on if the separator is dumping continuously or intermittently:

$$EF = \begin{cases} \begin{cases} FF \times {}^{140}/_{1.64} \times n_{wells}, & p < {}^{Q_{site}}/_{140} \\ 0, & p \geq {}^{Q_{site}}/_{140} \end{cases}, & Q_{site} < 140 \\ FF \times Q_{well} \times n_{wells}, & Q_{site} \geq 140 \end{cases}$$

On average, we assume, a site will contain one or more wells with a single separator. Therefore, in evaluating if a separator is dumping continuously or intermittently, we convert the well level throughput, $Q_{well}$, to a site level throughput, $Q_{site} = Q_{well} \times 1.64$.

Here, 1.64 is the average number of wells per site according to Enverus data. *p* is a random number evaluated for every well.

- *Equipment leaks and vents due to equipment malfunction*: we assume equipment failures and leaks can occur at all tanks (both controlled and uncontrolled). Equipment leaks are calculated using the same "stochastic failure" approach as other equipment. For vents due to equipment malfunction, we also use the "stochastic failure" approach, but with the exception that we draw exclusively from ERG [17].

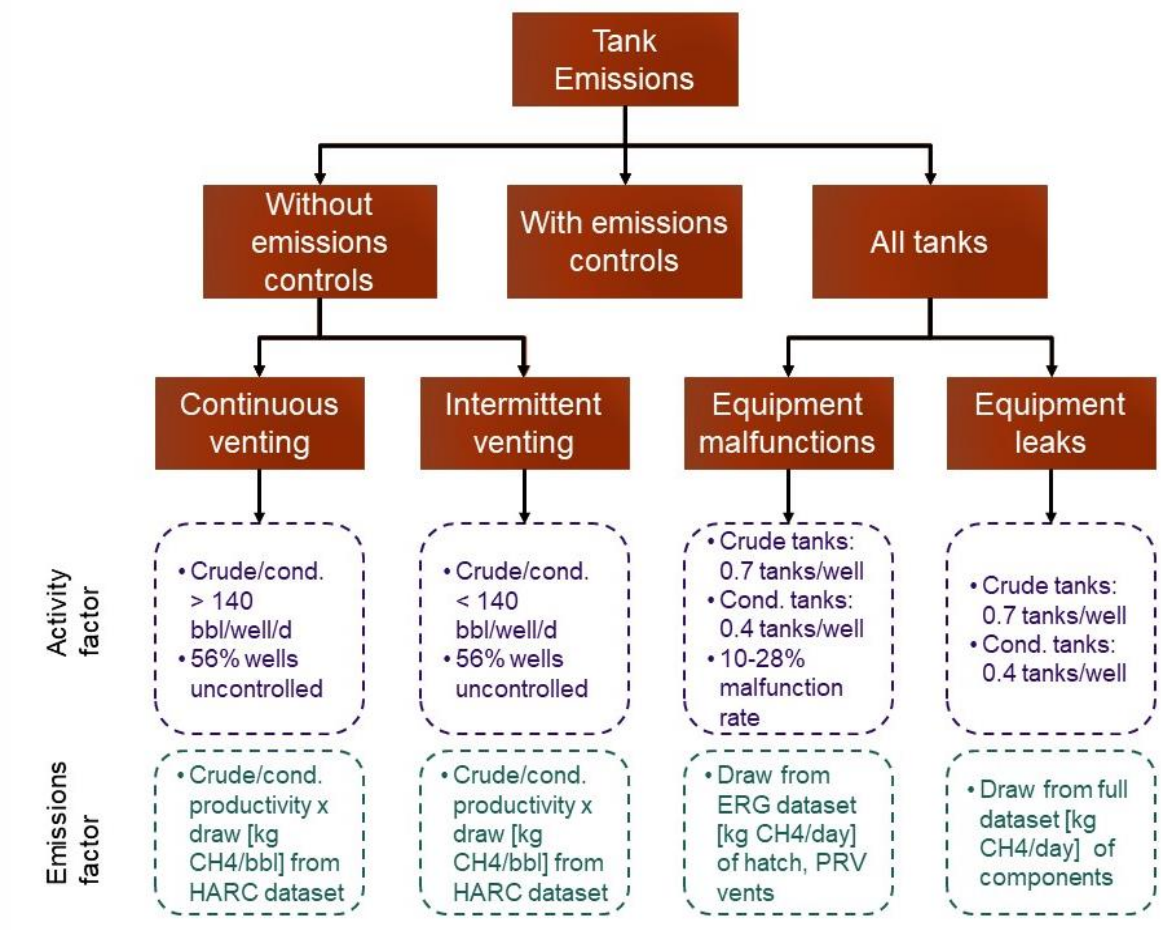


**Figure S9: Emissions mechanisms of crude and condensate storage tanks**

Though we depict emissions mechanisms in **Figure S9** as if they are mutually exclusive, it must be acknowledged that there is likely overlap. In particular, the ERG dataset (source for equipment malfunction emissions, [17]) likely contains some emissions from flashing, and the HARC study (source for flashing emissions, [23]) likely contains emissions from equipment malfunction. However, evidence from these studies suggests that the overlap could be minimal (see further description of these studies in section 5).

- In the HARC study [23], tanks were inspected prior to vent measurements. Thief hatches were closed and any tanks with rusted holes were not measured.
- We removed three tank samples (17, 25, and 26) from the HARC dataset. Reanalysis by ERG (distinct from the previously mentioned Fort Worth campaign, [24]) suggested, based on what was measured versus the physically possible flash emissions, that these measurements were likely due to equipment malfunction. By removing these measurements, it is more likely that the HARC dataset only contains flash emissions, and not emissions due to equipment malfunction.
- Measurements by ERG [17] labelled as "equipment malfunction" are from thief hatches, rusted holes, and PRVs, locations not sampled in the HARC study. However, we also include some emissions measurements classified by ERG as "vents" given that (much like the three emissions measurements removed in the HARC study) these measurements could also be due to equipment malfunction.

However, to provide a conservative estimate, we model uncertainty in double counting between the two tank emissions sources (See Section 4.4.2)

#### *3.3.3. Liquids unloadings*

Liquids unloading data are obtained from Allen et al. [25]. Allen et al. characterize emissions from 107 wells, in a variety of regions and configurations (i.e., horizontal, vertical). Based upon average reported events per well, events per year, and emissions per event, data in Allen et al. was converted to distributions of emissions per well. These distributions were embedded in OPGEE and sampled randomly for each well in a similar fashion to equipment modelling using stochastic failure.

#### *3.3.4. Completions and workovers*

OPGEE emissions factors for completions and workovers are based on EPA GHGRP data (operators report emissions from workovers and completions to the GHGRP under subpart W of 40 CFR section 98 [6]). Distributions were developed by type of wells for wells employing (i) hydraulic fracturing, (ii) flaring of completion emissions, and (iii) reduced emissions completions. Values were randomly sampled from these distributions according to the number of completion events reported for 2015 in the GHGI.

Data reported by operators through the EPA's Greenhouse Gas Reporting Program (GHGRP) are made publicly available through the Envirofacts website. We estimate emissions from well

completions and well workovers using the “Envirofacts GHG Customized Search” tool [26]. The methods to gather data for drilling completions and workovers are as follows

1. Access EPA custom GHG search site on December 5, 2019. URL: https://www.epa.gov/enviro/greenhouse-gas-customized-search
2. Click on "Petroleum and natural gas systems"
3. Select reporting year 2015 and click "Go to step 2"
4. Click on appropriate tables for subject. Click first on “EF_W_COMP_WORKOVERS_FRAC” to obtain information for fractured well completions and workovers.
5. Click on step 3: Select Columns button
6. Select all columns
7. Click on "Go to step 4"
8. Do not select any narrowing criteria
9. Click on "output to CSV file"
10. Repeat steps 4-9 for second dataset “EF_W_COMP_WORKOVERS_NO_FRAC” to obtain information for non-fractured well completions and workovers.

These two datasets are then processed to generate per-well emissions rates.

For the dataset containing wells completed or worked over with hydraulic fracturing, the following processing workflow was followed:

1. Remove rows with no wells reported, as these rows are not useful in calculating per-well emissions rate
2. Compute per-well $CH_4$ emissions by dividing $CH_4$ emissions in tonnes per year by well completion events per year
3. Rows with zero reported emissions are maintained for computing means (i.e., where wells are reported but no emissions are reported)
4. Separate results into sub-datasets depending on the activity pursued
    a. Split dataset into completion and workovers
    b. Further split dataset into completions with and without flaring and with and without RECs
    c. Further split dataset into workovers with and without flaring and with and without RECs

For the dataset containing wells completed or worked over without hydraulic fracturing, the following processing workflow was followed:

1. Remove rows with no wells reported, as these rows are not useful in calculating per-well emissions rate

2. Compute per-well $CH_4$ emissions by dividing $CH_4$ emissions in tonnes per year by well completion events per year
3. Remove rows where per-well emissions are zero (i.e., where wells are reported but no emissions are reported)
4. Separate results into sub-datasets depending on the activity pursued
    a. Split dataset into completion and workovers
    b. Further split dataset into completions with and without flaring
    c. Further split dataset into workovers with and without flaring

Finally, for all sub-datasets described above, the mean $CH_4$ emissions per event was calculated.

This approach is similar to the approach taken by Alvarez et al. [1]. However, we differ in how we use activity factors to calculate total US completion and workover $CH_4$ emissions. Examining activity data in the 2020 GHGI, GHGRP subpart W counts are applied for some emissions sources (e.g., natural gas system HF completions) but not others (e.g., natural gas system non-HF completions). This could be due to the fact that subpart W reporting is still incomplete for certain categories (presumably, not all well completions are reported by operators). Therefore, for our estimation of total emissions we use emissions factors calculated using subpart W data and AFs from GHGI (**Table S12**). Based on these calculations we find total completion and workover $CH_4$ emissions to be 39.8 Gg for the natural gas sector and 109.0 Gg for the petroleum sector.

**Table S12: 2015 emissions from completions and workovers based on emissions factors derived from GHGRP subpart W data and activity factors derived from the GHGI**

| | Emissions factor [tonne/event] | Activity factor [events/year] | Total [tonne/year] |
|---|---|---|---|
| Natural gas systems | | | |
| HF Completions - Non-REC with Venting | 17.390 | 105 | 1825.9 |
| HF Completions - Non-REC with Flaring | 6.951 | 326 | 2268.1 |
| HF Completions - REC with Venting | 5.312 | 3053 | 16217.5 |
| HF Completions - REC with Flaring | 5.271 | 1795 | 9459.3 |
| Non-HF Completions - vented | 5.936 | 602 | 3571.2 |
| Non-HF Completions - flared | 0.039 | 188 | 7.4 |
| HF Workovers - Non-REC with Venting | 2.835 | 199 | 564.9 |
| HF Workovers - Non-REC with Flaring | 0.307 | 66 | 20.4 |
| HF Workovers - REC with Venting | 2.823 | 1833 | 5175.0 |
| HF Workovers - REC with Flaring | 0.601 | 339 | 203.4 |
| Non-HF Workovers - vented | 0.066 | 7303 | 482.1 |
| Non-HF Workovers - flared | 0.005 | 349 | 1.7 |
| Petroleum systems | | | |
| HF Completions: Non-REC with Venting | 17.390 | 1494 | 25980.4 |
| HF Completions: Non-REC with Flaring | 6.951 | 1517 | 10544.1 |
| HF Completions: REC with Venting | 5.312 | 3630 | 19283.2 |
| HF Completions: REC with Flaring | 5.271 | 5494 | 28957.1 |
| Well Completion Venting (less HF completions) | 5.936 | 3610 | 21427.6 |
| HF Workovers: Non-REC with Flaring | 0.039 | 267 | 10.5 |
| HF Workovers: REC with Flaring | 2.835 | 976 | 2767.0 |

## 3.4. Equipment-level activity factors

In the GHGI, direct equipment counts are *not* available for every year. As an approximation, the GHGI uses "activity drivers" ($AD$) such as gas production, number of producing wells, or system throughput. *AD* are multiplied by a scaling factor (e.g., separators per well, $af_k^*$) derived from a subsample of the population. For each piece of equipment, we employ well counts as the activity driver, $AD$. Since the 2018 GHGI, the EPA has calculated activity factors for most equipment using scaling factors based on GHGRP data. Scaling factors based upon reporting year 2015 equipment counts are multiplied by year-specific wellhead counts to calculate year-specific equipment counts [27].

$$af_k = AD \cdot af_k^*$$

Prior to 2016, the EPA included gathering and boosting as a subsection of the production segment [28]. Equipment (such as small compressors and dehydrators) were included which could exist at either a well pad or a centralized gathering facility. Therefore, disaggregating well pad emissions from gathering and boosting emissions was difficult. This point is mentioned in Marchese et al. [7], who documented a possible distribution of equipment between well pads and gathering and boosting facilities. The EPA mention the Marchese et al. study [28], but since 2016 it is not clear if the Marchese et al. corrections were applied in subsequent inventories. We apply the corrections suggested by Marchese et al. to our scaling factors (**Table S13**).

These scaling factors, $af_k^*$, are applied for each equipment *k*. Because our algorithm iterates across equipment count, the need for $AD$ in the formula explicitly disappears. For each bin, *i*, emissions are calculated well-by-well. For a single well, *j*, equipment-level emissions are calculated by multiplying a randomly drawn emissions factor, $EF_{i,j,k}$ [kg/equipment/day], by its respective activity scaling factor, $af_k$ [# equipment/well]. In the OPGEE VF algorithm, $af_k^*$ is represented as follows:

$$Q_{population} = \sum_{i=1}^{n_{bins}} \left\{ \sum_{j=1}^{n_{wells,i}} \left[ \sum_{k=1}^{n_{equip}} EF_{i,j,k} * X \right] \right\}$$

Where,

$$X = \begin{cases} 1 & p \leq af_k^* \\ 0 & p > af_k^* \end{cases}$$

**Table S13: Scaling factors, $af_k^*$, applied**

| Equipment | GHGI AD scaling factor (count per well)[1] | Fraction allocated to production sector[2] |
|---|---|---|
| Natural gas system | | |
| Heater | 0.13 | 0.96 |
| Separator | 0.71 | 0.98 |
| Dehydrator | 0.03 | 0.92 |
| Meters | 0.84 | 0.97 |
| Small Recip compressor | 0.08 | 0.29 |
| Chemical Injection Pneumatic controllers | 0.18 | 1.00 |
| Pneumatic controllers | 3.00 | 1.00 |
| Tanks | 0.40 | 1.00 |
| Petroleum system | | |
| Heater-treater | 0.19 | 0.96 |
| Separator | 0.36 | 0.98 |
| Header | 0.23 | 1 |
| Chemical Injection Pneumatic controllers | 0.10 | 1 |
| Pneumatic controllers | 3.00 | 1 |
| Tanks | 0.75 | 1 |

[1]Scaling factor for pneumatic controllers derived from analysis of data from Allen et al et al. [8]. Scaling factor for tanks and all other equipment derived from EPA analysis of GHGRP data ([21] and [27], respectively).
[2]Fraction allocated based on analysis by Marchese et al et al. [7]

# 4. Producing a US O&NG production segment CH4 estimate

This section describes how our $CH_4$ emissions tool, implemented in OPGEE, is used to generate an estimate of US O&NG production segment emissions. We begin by describing our well and O&NG production dataset, and how this dataset was translated to representative OPGEE "fields" for analysis (Section 4.1) Next, we describe minor adjustments to how several emissions sources (methane slip, completions and workovers) were modelled (Section 4.2) and how additional analysis was performed to make our results comparable to site-level studies (Section 4.3). We conclude with a summary of how uncertainty is treated in our model (Section 4.4).

## 4.1. Development of representative "fields" for analysis

On the OPGEE *Inputs* sheet, out of the >50 possible inputs, only a small number are required for analysis of $CH_4$ emissions. These include O&NG production, well count, GOR, $CH_4$ content, and a categorical liquids-unloading variable.

#### *4.1.1. Gas composition*

We apply the same $CH_4$ content as the EPA GHGI [2], which is itself based upon the Gas Technology Institute Unconventional Natural Gas and Gas Composition Databases [29]. The 2015 average $CH_4$ content, weighted by regional production, used in OPGEE is 82.2% (volume basis).

#### *4.1.2. Well count and O&NG production dataset*

Well count, oil production, and GOR are sourced from Enverus [30]. While home institution of JSR and ARB, Stanford University, has direct access to Enverus, for the purposes of comparison with the Alvarez et al. [1] study, we requested the Enverus (previously known as DrillingInfo) dataset used in that study to base our analysis on. These data were obtained as "Drillinginfo_US_2015_Production_Data_Wells2Sites.xlsx" from David Lyon on 19/8/14.

The data were then filtered. Federal offshore wells were removed by filtering column "STATE" for "FO GULF" and "FO PACIFIC" and deleting the associated rows. This corresponded to 5201 wells, 1350 sites, and ~1 Tcf/yr gas production. Inactive wells were also removed (1202 wells, 0 Tcf/y gas production).

In this dataset wells had been previously clustered by David Lyon into "well sites" based upon proximity within a 50 m radius (see further description in the Alvarez et al. Supplementary information [1]). For the purposes of our analysis, well-site production data was "de-clustered" into well-level data. For each multi-well row in the array, new rows were created according to the number of wells in the site, and production was assigned according to the average well productivity at the site.

US wells were stratified into smaller representative subsamples, or "fields" on the basis of GOR and well-gas productivity. First, the dataset was split into four groups applying the same GOR cutoff as the EPA [31]: (i) Gas only wells, (ii) gas wells with oil production (GOR > 100 Mscf/bbl), (iii) oil wells with associated gas (GOR < 100 Mscf/bbl), (iv) and lastly oil only wells (no gas production reported, see Section 4.1.4). From these datasets, we then split into ten productivity tranches for gas only, gas with oil, and oil with gas datasets, and four productivity tranches for the oil-only dataset (See **Table S14-S17**). The productivity tranches are defined using lower and upper cutoffs in mean daily gas production rate measured in Mscf/day.

**Table S14: Gas wells (gas only) productivity tranches**

| Bins (Mscf/well/day) | Count | Mean gas rate (Mscf/well/day) | Total gas (Mscf/day) | Total oil production (bbl/day ) |
|---|---|---|---|---|
| 0.00-1.00' | 38,225 | 0.4 | 15,065 | 0 |
| 1.00-5.00' | 65,138 | 2.8 | 180,330 | 0 |
| 5.00-10.00' | 43,154 | 7.3 | 313,240 | 0 |
| 10.00-20.00' | 44,523 | 14.4 | 642,190 | 0 |
| 20.00-50.00' | 57,148 | 32.4 | 1,851,000 | 0 |
| 50.00-100.00' | 27,868 | 69.5 | 1,938,200 | 0 |
| 100.00-500.00' | 31,429 | 228.9 | 7,193,200 | 0 |
| 500.00-1000.00' | 6,727 | 690.3 | 4,643,900 | 0 |
| 1000.00-10000.00' | 5,875 | 2,571.8 | 15,109,000 | 0 |
| 10000.00-inf | 87 | 20,103.0 | 1,748,900 | 0 |

**Table S15: Gas wells (with oil production) productivity tranches**

| Bins (Mscf/well/day) | Count | Mean gas rate (Mscf/well/day) | Total gas (Mscf/day) | Total oil production (bbl/day) |
|---|---|---|---|---|
| 0.00-1.00' | 400 | 0.6 | 246 | 1 |
| 1.00-5.00' | 2,880 | 3.0 | 8,648 | 39 |
| 5.00-10.00' | 3,907 | 7.5 | 29,482 | 111 |
| 10.00-20.00' | 9,384 | 15.2 | 142,900 | 496 |
| 20.00-50.00' | 30,938 | 34.5 | 1,068,800 | 3,673 |
| 50.00-100.00' | 29,916 | 71.1 | 2,126,500 | 6,929 |
| 100.00-500.00' | 30,031 | 197.9 | 5,943,900 | 20,835 |
| 500.00-1000.00' | 3,094 | 696.6 | 2,155,300 | 8,337 |
| 1000.00-10000.00' | 2,684 | 2,376.7 | 6,379,100 | 19,625 |
| 10000.00-inf | 22 | 15,955.0 | 351,000 | 1,133 |

**Table S16: Oil wells (with gas production) productivity tranches**

| Bins (Mscf/well/day) | Count | Mean gas rate (Mscf/well/day) | Total gas (Mscf/day) | Total oil production (bbl/day) |
|---|---|---|---|---|
| 0.00-1.00' | 65,606 | 0.4 | 23,107 | 192,790 |
| 1.00-5.00' | 89,163 | 2.6 | 231,830 | 425,170 |
| 5.00-10.00' | 38,948 | 7.2 | 280,540 | 208,860 |
| 10.00-20.00' | 44,410 | 14.4 | 638,950 | 294,520 |
| 20.00-50.00' | 54,343 | 31.9 | 1,735,300 | 581,920 |
| 50.00-100.00' | 32,775 | 71.1 | 2,331,500 | 856,460 |
| 100.00-500.00' | 42,848 | 216.8 | 9,290,800 | 2,722,700 |
| 500.00-1000.00' | 7,280 | 687.2 | 5,003,100 | 953,610 |
| 1000.00-10000.00' | 4,464 | 2,213.1 | 9,879,200 | 676,700 |
| 10000.00-inf | 348 | 15,331.0 | 5,335,200 | 99,644 |

**Table S17: Oil wells (oil only) productivity tranches**

| Bins (Mscf/well/day) | Count | Mean gas rate (Mscf/well/day) | Total gas (Mscf/day) | Total oil production (bbl/day) |
|---|---|---|---|---|
| 0.00-0.50' | 114,480 | 0.2 | 18,160 | 38,135 |
| 0.50-1.00' | 27,038 | 0.7 | 19,398 | 40,064 |
| 1.00-10.00' | 45,264 | 3.0 | 133,570 | 269,770 |
| 10.00-inf | 4,792 | 22.4 | 107,320 | 205,210 |

#### *4.1.3. Liquids unloadings*

These datasets are split one final time into OPGEE columns based on liquids unloadings. For gas wells, 10.4% have liquids unloadings events with plunger lift and 7.1% without plunger lift [2]. Oil wells (GOR <100 mscf/bbl) do not require liquids unloadings events.

#### *4.1.4. Treatment of "oil only" wells*

For wells reporting 0 gas production to DrillingInfo (henceforth "oil-only" wells), we assume some amount of unreported gas is produced and could be lost as fugitive emissions before use. This is because even very heavy oil contains some dissolved hydrocarbon gases. In order to approximate gas co-produced from oil wells, we need to calculate the gas-oil ratio. The solution gas-oil ratio, $R_s$, is a function of the oil and gas composition, pressure, and temperature. $R_s$

reaches a maximum at pressures beyond the bubblepoint pressure, $P_b$. As the pressure drops below $P_b$, $R_s$ decreases as gas comes out of solution. We calculate $R_s$ at $P_b$, and assume that when the crude oil is exposed to atmospheric pressure at the surface in atmospheric storage tanks at ambient temperatures, all gas exolves.

We use the following empirical relationship from Al Shammasi [32], as reported in Fanchi Vol 1 [33]:

$$R_s = P_b^{a_2^{-1}} e^{\frac{a_3}{a_2}\gamma_o\gamma_g} \gamma_o^{-\frac{a_1}{a_2}} \gamma_g^{-1} (T_r + 459.67)^{-1}$$

The following assumptions are made based on the average conditions from the reservoir sample in Fanchi (pg 265): $T_r$ = 185ºF, $P_b$ = 2041 psia, $\gamma_g$ = 0.774 (see Fanchi for coefficients $a_1$, $a_2$, $a_3$). Holding these parameters fixed, we now have a relationship for solution gas-oil ratio ($R_s$) variation with crude API gravity ($\gamma_o$).

Although there are columns for API gravity in the DrillingInfo dataset, these columns are relatively sparse (and for specific basins, there is no data at all). Therefore, for data on API gravity we use the Wood MacKenzie (WM) dataset. Rather than at a well-level, API gravity exists in the WM dataset at the field-level. This dataset was processed to produce field-level API gravity dataset of 2130 entries. The data set is further filtered for rows classified as “Oil” fields, with non-zero oil production and API gravity > 0 (382 rows remain).

Next, the Fanchi equation is used to calculate $R_{so}$ from API gravity. We find an average API gravity of 34.8 API and an average $R_{so}$ of 503 scf/bbl. This is larger, but a similar order of magnitude, compared to a similar analysis performed by Alvarez et al [1].

$R_{so}$ values are randomly assigned to oil-only rows in the DI dataset as we do not have API values in most cases.

## 4.2. Deviations from standard OPGEE functionality in this paper

Due to the specific application of this study, some modifications were made to the standard OPGEE functionality. These modifications are as follows.

### *4.2.1. Autorun macro*

Although OPGEE 3.0 contains built in Monte Carlo uncertainty functionality, the application of this paper required a modified approach. The existing OPGEE 3.0 Monte Carlo functionality is designed to test uncertainty in missing data and the use of "smart default" parameters, but it is not designed to robustly test the full uncertainty in the venting and fugitives tools. For this study, we develop a Macro titled "Autorun", described in this section. It is possible that "Autorun" could be formally incorporated into future OPGEE 3.0 versions.

Due to the randomized nature of the component-level bootstrapping algorithm, equipment-level emission factor distributions passed to OPGEE are variable. To explore how this uncertainty propagates to our final $CH_4$ emissions estimates, we generate 100 unique equipment-level emission factor distributions and export these distributions to .CSV files. In OPGEE, new equipment-level emission factor files are imported after each Monte Carlo iteration.

The OPGEE 3.0 model applied in this analysis was adjusted such that with an *Inputs sheet* setting "Monte Carlo realizations input = 1", OPGEE still runs in random mode. Although we still want OPGEE to make random draws, we only want one "internal" OPGEE realization (our 100 Monte Carlo realizations are run outside of OPGEE in the Autorun wrapper).

### *4.2.2. Methane slip*

Compressor fuel use and emissions are calculated in OPGEE as a function of gas throughput and the required compression ratio between wellhead pressure and separator working pressure. Because (i) this approach is not consistent with the inventory approach of this paper (e.g., calculation of per well emissions) and (ii) we are concerned that the current approach in OPGEE underestimates emissions from methane slip, for this paper we run a separate calculation external to OPGEE.

Emissions factors for methane slip from natural gas reciprocating engines are calculated according to an adjusted emissions factor (EF', kg/hp*hr) and the power rating of the engine (P, hp).

$$EF = EF' \times P \times 24$$

Following Zavala Araiza et al. [22], EF' is assigned a normal distribution with a mean of 0.00125 kg/hp*hr. This number is based on NSPS specifications, with a 25% adjustment upwards to account for "real-world performance" [22], [34]. The standard deviation of the normal distribution ($\sigma$ = 0.000319 kg/hp*hr) reflects 95% CI of +/- 50% around the mean. Power ratings of on-site reciprocating compressors are drawn randomly from the ERG data set [17], which includes a record of all compressors found in their Fort Worth campaign. It is not clear how representative the wellpad compressor power distribution from the ERG study is of the national distribution.

#### *4.2.3. Completions and workovers*

OPGEE 3.0's primary functionality is to calculate a carbon intensity (mass of carbon dioxide equivalent per megajoule of primary energy produced). In calculating carbon intensity, completion and workover emissions are amortized over the lifetime energetic production of the well. However, for this calculation we are interested in a gross, non-amortized emission estimate for 2015. Rather than work around these calculations in OPGEE, we calculate non-amortized completion and workover emissions outside of OPGEE.

## 4.3. Grouping per-well model outputs into production sites for a consistent comparison with facility-level studies

The facility-level measurements synthesized by Omara et al. [11] and Alvarez et al. [1] aggregate, as the name implies, emissions from all equipment located at a production-site (e.g., well-pad). The nature of facility-level studies is to remotely measure all emissions from equipment that comprise a single production "site", which includes one or multiple wells, pumps, separation equipment, tanks, and potentially other processing equipment. In contrast, OPGEE outputs emissions for each type of equipment on a per well basis. In order to compare emissions results from Omara and Alvarez with our study, we needed to "cluster" our per-well results into facility-level groupings.

First, it should be noted that, although the DrillingInfo dataset describes which wells are clustered into single-well and multi-well facilities, because wells were binned into specific columns for processing in OPGEE this detail was lost. In order to cluster our OPGEE results *post-hoc*, the following approach was taken:

1. For clustering, we use the “well-count” column from the same DrillingInfo dataset described in section 3.1.
2. Both OPGEE output data and the DrillingInfo dataset are binned on the basis of product stream – gas only, gas with associated oil, oil wells with associated gas – with the exception that oil only wells are removed (as they were in Omara et al. [11]).
3. The DrillingInfo dataset is further binned into the same productivity tranches as our OPGEE output results.
4. We iterate across rows (well, production, emissions combinations) in the OPGEE outputs and randomly assign a bin-specific “well-count”.
5. According to the drawn well count, that number of per-well emissions are grouped into a site-level emissions value.

## 4.4. Uncertainty analysis

This study applies the Monte Carlo method to estimate uncertainty. Input parameters – component-level emission factors, component counts, and fraction of components emitting – are assigned distributions, and the range of uncertainty in these distributions is propagated through the model. Therefore, the full range of uncertainty is captured to the extent that these distributions encompass the full set of possible values.

A single OPGEE simulation will produce an estimate of total US $CH_4$, but it will not output a distribution. For a distribution, OPGEE must be run multiple times. We use the “Autorun” macro, described in Section 4.2.1, to produce a distribution of 100 Monte Carlo results.

In this section we review treatment of uncertainty in the equipment-level emission factors, treatment of uncertainty in tank emissions, and conclude with a brief comment on the limitations of our uncertainty assessment.

### *4.4.1. Uncertainty in equipment-level emission factors*

The uncertainty in component-level emission factor distributions is captured in the resampling algorithm discussed in Section 3.3.1. However, equipment-level emission factors are also a function of component counts and fraction of components leaking. Since a single equipment-level emission factor distribution is a function of constant component counts and fraction of components emitting values, a full assessment of uncertainty requires calculating multiple equipment-level emission factor distributions. Therefore, a different set of equipment-level emission factor distributions is used for each of our 100 Monte Carlo simulations. Distributions

for component counts and fraction of components emitting are approximated as uniform distributions between the maximum and minimum values found in our surveyed studies (see **Table S5** and **Table S6** for component counts and **Table S10** for fraction of components emitting). Unfortunately, our sparse dataset does not allow us to determine a likely distribution shape for these parameters so a uniform distribution is assumed for simplicity.

#### *4.4.2. Uncertainty in tank emissions*

In Section 3.3.2, we described how we treat tank flash emissions and abnormal venting emissions separately (based on the ERG and HARC sources [17], [23]) but acknowledge that there is likely overlap between the studies drawn upon. To provide a conservative estimate of tank emissions, we model uncertainty in double counting between the two emissions sources (**Figure S10**). We denote the probability of an emissions event from HARC *P(A)*, and the probability of an emissions event from ERG *P(B)*, with the probability of intersection $P(A \cap B)$.

What we are interested in is the probability of an ERG emitting event, given an uncertain amount of overlap with HARC. We denote ERG emissions not overlapping with HARC as *B'*. In other words, what fraction of emissions events in the ERG dataset are emissions events due to equipment malfunction, not already represented in the HARC dataset? This can be denoted as:

$$P(\mathrm{B}') = P(\mathrm{B}) - P(\mathrm{A} \cap \mathrm{B})$$

But how do we describe $P(A \cap B)$? We can conservatively assume that $A < B$ (or that an emissions event due to regular functioning is more likely than an emissions event due to irregular functioning. Therefore, the size of $A \cap B$ could be as small as zero (*A* and *B* are mutually exclusive) and as large as *P(B)* (*P(B)* is contained within *P(A)*).

To capture this range of possibilities in our modelling we adjust our "fraction leaking" values for tank venting from pressure relief valves. The lower bound is set at 0%, given the possibility of complete overlap between *P(A)* and *P(B)* (**Table S10**). The upper bound is that derived from ERG directly, which accounts for the possibility of null overlap between *P(A)* and *P(B)*.

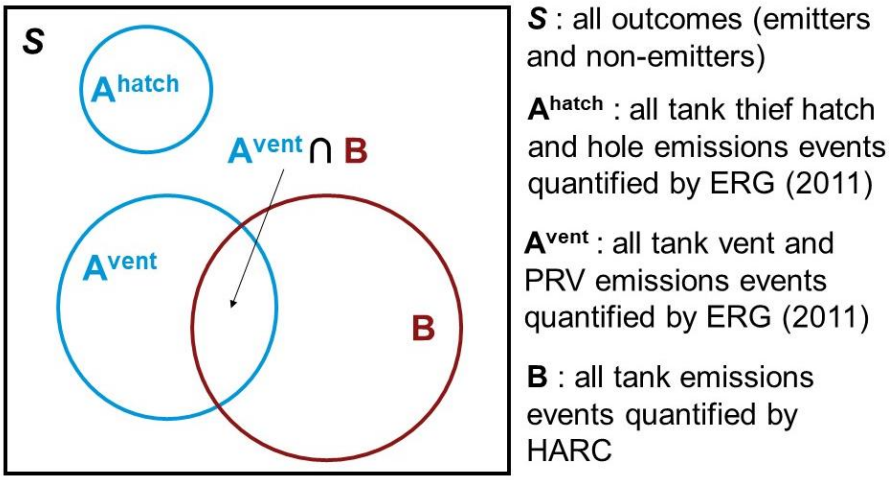


**Figure S10: Venn diagram illustrating possible overlap between the ERG** [17] **and HARC** [23] **tank emissions measurements**

### *4.4.3. Limits to uncertainty assessment of this study*

Given the data limitations in component-level assessments, however, our distributions cannot capture the full range of uncertainty in component-level input parameters. Our dataset does not encompass all operators in the US, who may differ in leakage management. Its also possible that our dataset doesn't represent all possible configurations of equipment (e.g., component counts). Finally, we assume equipment-level activity factors (number of equipment per well) identical to the GHGI (which are themselves based on GHGRP data) although equipment counts will be highly variable from site to site. This represents a significant source of uncertainty which is not captured by our model. Thus, it is reasonable to assume that the uncertainty ranges presented here are a lower bound on the possible ranges.

# 5. Production segment $CH_4$ in the US Greenhouse Gas Inventory

The purpose of this section is to explain in detail how the US EPA Greenhouse Gas Inventory (GHGI) estimates production segment $CH_4$ emissions with the goal of reconstructing the GHGI total emissions values. Unfortunately, for a variety of reasons including data gaps (e.g., Star Environmental datasets, see Section 5.2.4) and methodological alignment (see Section 5.2.2) we cannot fully reconstruct the GHGI total CH4 emissions estimate. But because our approach uses activity factors very similar to GHGI activity-factors (see Section 2.3) differences in total emissions can be isolated to differences in equipment-level emission factors. Therefore, the focus of this section will be on decomposing GHGI equipment-level emission factors into their underlying data for comparisons with the underlying data of this study.

We begin by investigating the broad categorization of $CH_4$ emissions within the GHGI production segment (Section 5.1), which includes all equipment associated with a well pad and ends prior to centralized gathering and processing facilities (**Figure S2**). We focus our attention on equipment leaks and tank emissions because this is where we observe the biggest discrepancy with our study (**Figure 3,** main text).

Sections 5.2-5.3 describe the process of reconstructing GHGI equipment-level emission factors from the underlying data sets for equipment leaks and storage tanks, respectively. Both sections contain a similar approach: reviewing the studies underpinning GHGI equipment-level emission factors and their associated datasets, deriving the approach to reconstructing the emissions-factors (component-level and equipment-level) from the datasets, and verifying our reconstructed emissions-factor distributions by comparing our averaged data with factors reported in the various studies.

The goal of this reconstruction exercise is to produce decompositions of the data used to produce GHGI equipment-level emission factors (e.g., component-level emission factors, component counts, and fraction of components emitting) for a harmonized comparison with the results of this study.

## 5.1. Overview of the US GHGI production segment

The US EPA has produced a GHGI since 1997. Each release updates historical and current GHG emissions from the US across all anthropogenic sources [2]. GHGs inventoried include carbon

dioxide, methane, nitrous oxide, hydrofluorocarbons and others. Methane emissions contribute 10% of US anthropogenic GHG emissions (with 100 year GWP = 25, [35]). According to the 2020 GHGI, 2018 methane emissions are estimated to be 25.4 Tg [2]. The largest source of methane emissions was agriculture (enteric fermentation and manure management) contributing 38%, with natural gas and petroleum systems (O&NG) contributing 28% of emissions. The O&NG sectors are contained within the broader energy sector in the GHGI. Within these sectors, emissions are categorized by supply chain segment (e.g., production, distribution, etc.). Within the O&NG sectors, emissions are calculated at a high resolution with 67 and 45 separate categories, respectively, for the production segment only [2]. Based on the approach of the GHGI, emissions have been steadily decreasing since the early 90s (**Figure S11**).

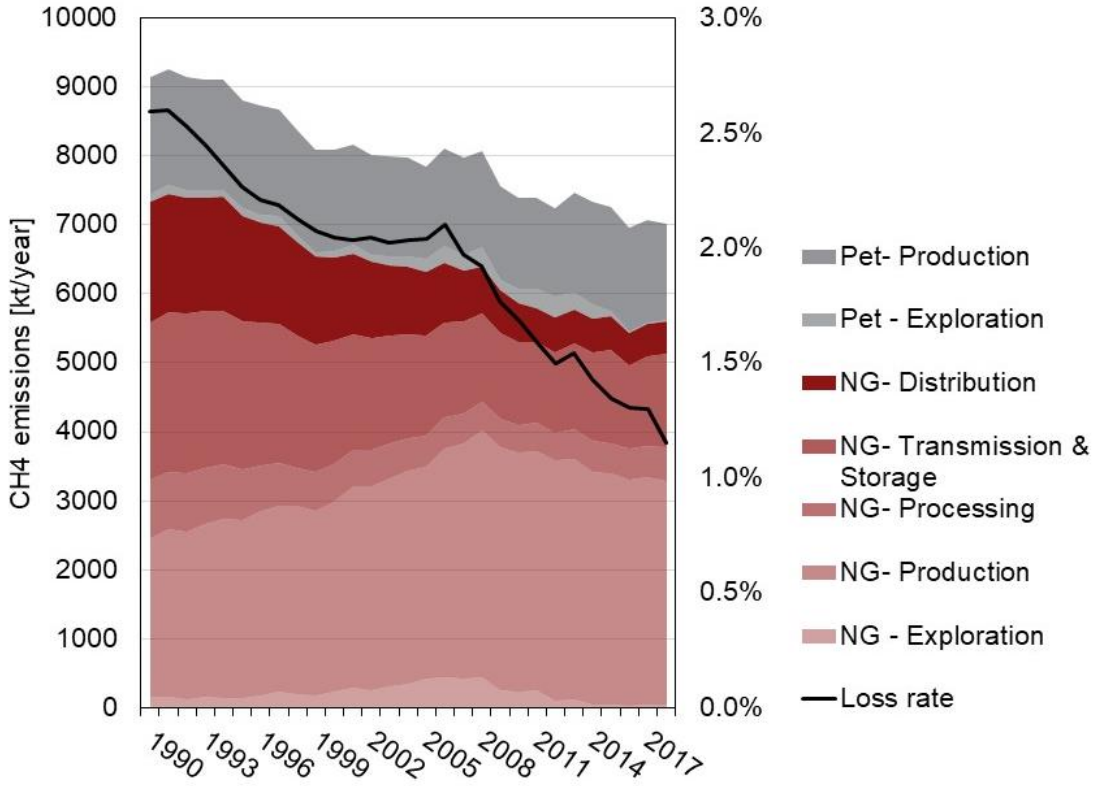


**Figure S11: Historic time series of methane emissions according to the GHGI** [2]**. Loss rate calculated as O&NG production $CH_4$ emissions divided by gross $CH_4$ withdrawals (using EIA data and a $CH_4$ fraction of 82.2%,** [29], [36]**)**

Consistent with the bottom-up approach described in the main text (**Figure 1**), aggregate source-specific emissions in the GHGI are calculated by multiplying emissions factors ($CH_4$ per unit

activity, usually number of equipment or in some cases volume throughput) by activity factors. The EPA further distinguishes between *potential emissions* and *net emissions*. *Potential emissions*, the product of emissions factors and activity factors, represent uncontrolled emissions. *Net emissions* represent *potential emissions* minus emissions reductions, which include voluntary or mandatory emissions reductions. However, data on emissions reductions (based on EPA analysis of the Natural Gas STAR program and New Source Performance Standards) are challenging to obtain at the source category, therefore emissions reductions are typically reported by production segment. Based on these limitations, any comparisons made in this study are with potential emissions before mitigation.

The methodology of the GHGI went relatively unchanged until 2009. However, after increased scrutiny, including a set of field studies led by University of Texas at Austin and the Environmental Defense Fund [8], [15], [25] the EPA began to revise the methodology. Improvements to the production segment of the O&NG sector have largely relied on data from the Greenhouse Gas Reporting Program (GHGRP). Since 2009, through the GHGRP the EPA has mandated that industrial facilities emitting > 25,000 tonne/y in $CO_2$eq. terms must report GHG data.

A list of notable (but not exhaustive) revisions to treatment of O&NG emissions in the GHGI includes:

- 2014 GHGI: $CH_4$ emissions estimates for completions and workovers were revised downwards based on GHGRP data [37]. This downward revision was consistent with field observations reported by Allen et al. [15].
- 2015 GHGI: $CH_4$ emissions estimates for pneumatic controllers were revised upwards based on GHGRP data [38]. This upward revision was consistent with field observations reported by Allen et al. [8], [15].
- 2017 GHGI: $CH_4$ emissions estimates for liquids unloadings were revised downwards slightly based on GHGRP data [21]. Prior to this adjustment, Allen et al. [25] had noted that GHGI estimates were already in close agreement with field observations. The 2017 GHGI also revised activity and emissions factor data for crude and condensate storage tanks (discussed further in section 5.3) [21].

Despite these modifications incorporating GHGRP data, the best available site-level estimates of production segment emissions suggest that the GHGI still substantially underestimates (see further discussion in main text and [1], [39]).

Based upon the modelling results of this study, we are able to isolate two sources likely contributing to the downward bias of the GHGI: equipment leaks and crude and condensate storage tanks. Our goal with this section is to reconstruct the GHGI published emissions factors to understand what drives low emissions estimates in the GHGI.

## 5.2. Reconstructing GHGI emissions factors for equipment leaks

The construction of equipment-level emissions-factors for equipment leaks in the GHGI is very similar to the approach of our model (see **Figure 1**, main text), therefore demonstrating how these emissions factors were constructed might illuminate sources of bias in the GHGI. Our approach to reconstructing equipment-level emission factors is two-fold (**Figure S12**). First, we demonstrate how equipment-level emission factors in the inventory are linked to underlying studies and datasets (Section 5.2.1). Second, we review the method of deriving equipment-level emission factors from the component-level emissions datasets (Section 5.2.2). Finally, we reconstruct component-level emission factors (Section 5.2.3) and perform a verification of our reconstructed factors with reported values in the underlying reports (Section 5.2.4).

### *5.2.1. Sources of emissions factors in the GHGI*

The EPA draws from separate reports for constructing equipment-level emission factors, and these reports themselves reference separate component-level datasets. In this section we will begin by outlining the sequence of different studies underpinning the GHGI. We will then describe how these various studies are used to calculate the equipment-level emission factors found in the GHGI. Recall from the previous section how the EPA GHGI constructs separate inventories for petroleum systems and natural gas systems, differentiating gas and oil wells at a cutoff GOR of 100 mscf/bbl [31]).

The structure of the GHGI is rooted in a suite of studies jointly commissioned by the American Petroleum Institute and the Gas Research Institute, conducted under contract by STAR Environmental ([3], [4], [40]). Some emissions sources have been updated using data from the GHGRP (see previous section), however many sources are still based on this original data. The GHGI cites a 1996 report by the Gas Research Institute ([41], henceforth referred to as the "GRI report") for natural gas systems and a 1996 calculation workbook by the American Petroleum

Institute ([42], henceforth referred to as "API 4638") for petroleum systems (see the first branch connecting the GHGI to these studies in **Figure S12**).

The GRI report and API 4638 were not measurement campaigns, rather these reports summarized the results of multiple earlier works. The GRI report references API ([3], sites 9-12) for the Western US natural gas system and Star Environmental [4] for the Eastern US natural gas system. API 4638 references data from API ([3], sites 1 – 8) for petroleum systems. Therefore, only two measurement campaigns underlie GHGI equipment leakage: API [3] and the Star Environmental [4] datasets (see the second branch connecting these studies to the GRI report and API 4638 in **Figure S12**).

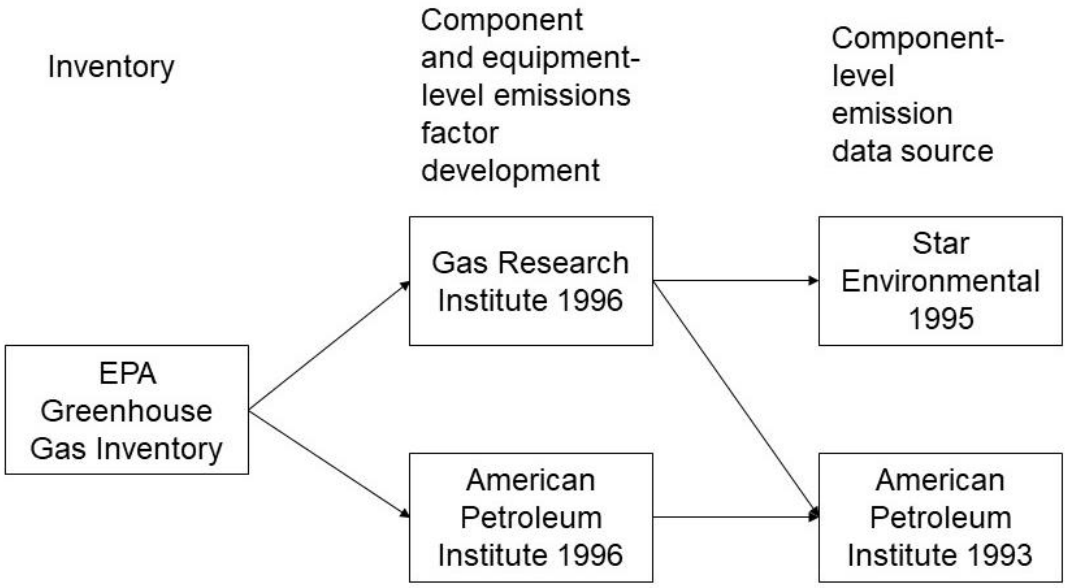


**Figure S12: Flow chart representing relationships between various cited studies in the GHGI** [2]**. The GRI study** [41] **and API** [42] **are cited by the GHGI in the development of component and equipment-level emission factors. These two studies cite Star Environmental** [4] **and API** [3] **for primary, component-level emissions data.**

The more detailed reporting of emissions factors in the GRI report and API 4638 versus the GHGI complicates the reconstruction of GHGI emissions factors. In the GRI report, emissions factors are further subdivided based on region and in API 4638 emissions factors are further subdivided based on product stream (light oil versus heavy oil). Fortunately, for petroleum systems the GHGI maintains this disaggregation by product stream. For natural gas systems, however, the GHGI only reports aggregate emissions factors and little documentation is

available on how emissions factors were constructed from the more detailed data in the underlying studies. To demonstrate the connection between the GRI report and the inventory we attempt an aggregation here.

For onshore natural gas production, the GRI report distinguishes between the Eastern US (Atlantic and Great Lakes regions) and Western US (rest of country) because "regional differences are found to exist" according to the study [41]. Up until the 2015 GHGI [43], emissions were reported in a form broken down by region (Northeast, Mid-Continent, Rocky Mountain, Southwest, West Coast, Gulf Coast, see **Table S18**), but they are no longer reported in this fashion and it is not clear why this practice was stopped. However, by averaging regional emissions factors and weighting according to equipment counts – calculated emissions factors closely match emission factors applied in the GHGI today (**Table S18**).

**Table S18: EPA GHGI emissions factors are calculated by averaging regional emissions factors and weighting according to equipment counts. The last time regional emissions factors (and not just averaged totals) were presented in the GHGI was in 2015** [43]**.**

| | Equipment counts | | | | | |
|---|---|---|---|---|---|---|
| | wells | separator | heater | dehydrator | meter | compressor |
| North East | 72,422 | 108,357 | 305 | 21,277 | 7,803 | 153 |
| Mid Continent | 74,442 | 43,996 | 41,063 | 14,101 | 135,554 | 11,429 |
| Rocky Mountain | 10,069 | 38,333 | 35,029 | 10,710 | 90,791 | 8,527 |
| South west | 22,250 | 27,624 | 13,320 | 6,853 | 69,076 | 6,685 |
| West Coast | 2,190 | 1,868 | 2,559 | 357 | 4,569 | 2,971 |
| Gulf Coast | 25,906 | 45,408 | 15,458 | 9,621 | 82,792 | 5,590 |
| | Emissions factors [$kgCH_4$/day] | | | | | |
| North East | 0.15 | 0.02 | 0.29 | 0.45 | 0.18 | 5.50 |
| Mid Continent | 0.14 | 0.02 | 0.29 | 1.83 | 0.18 | 5.39 |
| Rocky Mountain | 0.68 | 2.32 | 1.10 | 1.73 | 1.01 | 5.09 |
| South west | 0.72 | 2.40 | 1.13 | 1.79 | 1.04 | 5.26 |
| West Coast | 0.82 | 2.74 | 1.29 | 2.04 | 1.19 | 6.00 |
| Gulf Coast | 0.15 | 2.63 | 1.24 | 1.96 | 1.14 | 5.77 |
| | Regional and national average emissions factors [$kgCH_4$/day] | | | | | |
| East | 0.14 | 0.02 | 0.29 | 0.45 | 0.18 | 0.00 |
| West | 0.59 | 2.52 | 1.19 | 1.87 | 1.09 | 5.50 |
| **Total US** | **0.24** | **1.06** | **0.82** | **1.36** | **0.74** | **5.40** |

The GHGI reports adjustments to emissions factors year over year, but it is generally not clear in the GHGI documentation why these adjustments were made. Regardless of these adjustments,

the equipment-level emission factors have not deviated far from the values published in the GRI report. **Figure S13** compares the emissions factors over time (solid lines) from subsequent GHGI reports to the emissions factors from the original GRI report dataset (dashed lines) [41].

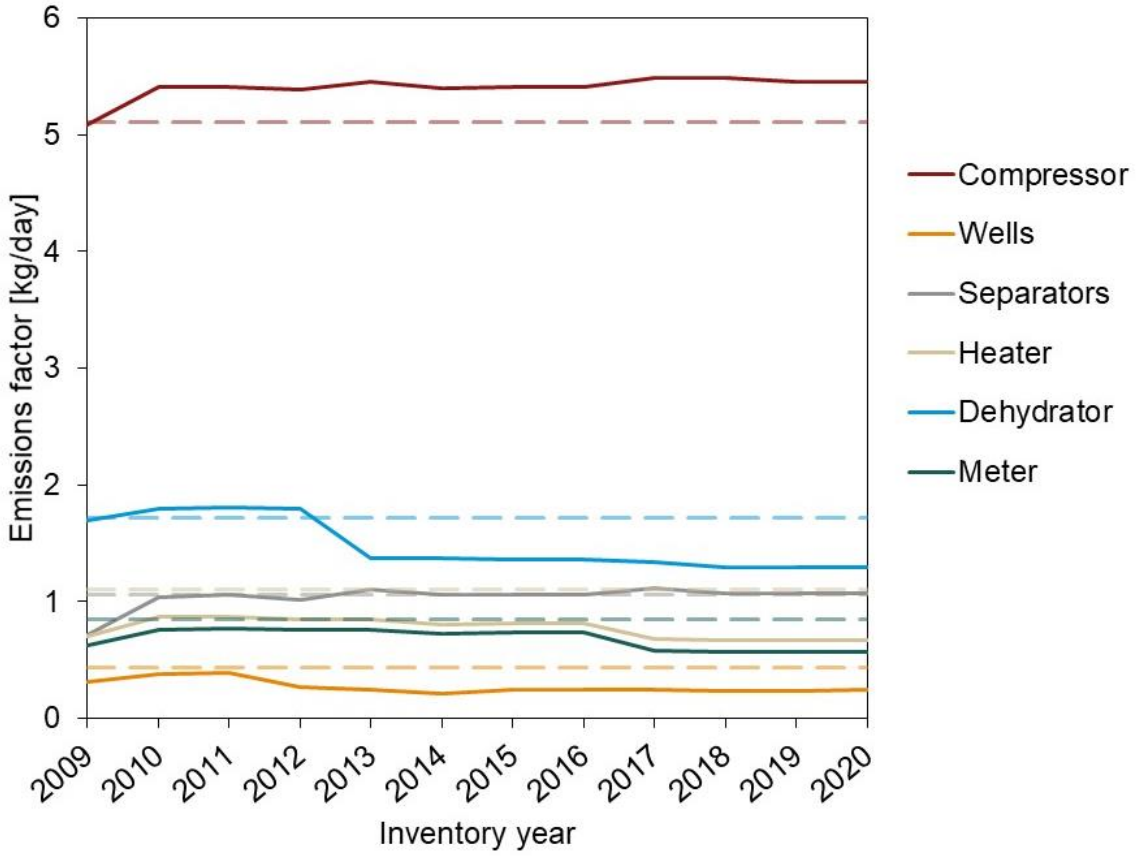


**Figure S13: Year-over-year EPA GHGI emissions factors (inventory years 2009 – 2020, corresponding to emissions factors for years 2007 – 2018, respectively** [2], [43]–[53]**) for NG systems (solid lines) closely match those reported in the GRI study** [41] **(hashed lines) with some deviation. This deviation is not described in published documentation (to the authors knowledge).**

### *5.2.2. Deriving emissions factors – General approach*

In the previous section, we described how equipment-level emission factors for equipment leakage in the GHGI are based on the GRI report and API 4638 [41], [42]. These emissions factors are themselves derived from component-level survey data from API [3] and Star Environmental [4] datasets (henceforth referred to as "API 4589" and "Star Environmental" datasets). The approach taken by the GRI report and API 4638 is broadly similar to our approach in that equipment-level emission factors represent a product of component-level data. In the

remainder of this section on the GHGI we focus on identifying the key decomposition factors of the equipment-level emission factors: Component-level emissions measurement data, component counts, and fraction of components emitting. In this section, we will briefly explain this approach, with a focus on the differences with the approach of our study. To begin we will focus on the component-level emissions data.

The general approach taken in the GRI report and API 4638, referred to as the "correlation approach", is summarized in the 1995 Protocol document ([5], henceforth referred to as the "EPA Protocol document"). The motivation of the correlation approach is the significant difference in labor between the two types of measurements made in methane surveys: "screening measurements" and "quantified emissions measurements". Ideally, because these techniques result in actual flux measurements, one could gather a large sample of quantified emissions measurements using the "bagging" or "high-flow sampler" techniques (see Clearstone [13] for a detailed description of these techniques), however this is often impractical. Instead, screening data are collected according to the EPA Method 21 protocol, usually using a flame ionization device (FID). Screening FID measurements are recorded in units of concentration (ppmv), and "correlation equations" (correlations of mass flux versus concentration) are used to transform screening data to units of emissions or mass flux (lb/day).

To fit the correlations, a large sample size of quantified emissions measurements with corresponding screening values is still required. Therefore, the EPA protocol document aggregates quantified emissions measurements across multiple industry segments (refineries, marketing terminals, oil and gas production facilities) and product streams (oil, gas). See Appendix C of the EPA Protocol document for more details [5].

Correlation equations are of the following form, where THC (total hydrocarbon) is the mean emissions rate of total hydrocarbons (lb/day) and ISV is the instrument screening value (ppmv). $a$ and $b$ are constants defined in **Table S19**.

$$\mathrm{THC} = a \cdot (\mathrm{ISV})^{b}$$

A key difference, therefore, between the GHGI-derived emissions factors and the emissions factors in our study is the use of correlation equations. Whereas the GHGI has used correlation equations to boost the sample size of underlying measurements our study does not, and instead

relies upon the aggregation of directly quantified leakage volumes reported across multiple studies.

**Table S19: Correlation equation parameters for various components (data from the GRI report** [41] **page 21)**

| Component Type | Correlation equation parameters | |
|---|---|---|
| | Constant, a | Exponent, b |
| Connector | $7.99 \times 10^{-5}$ | 0.735 |
| Flange | $2.35 \times 10^{-4}$ | 0.703 |
| Open-ended Line | $1.14 \times 10^{-4}$ | 0.704 |
| Pump Seal | $2.55 \times 10^{-3}$ | 0.610 |
| Vale | $1.21 \times 10^{-4}$ | 0.746 |
| Other | $6.98 \times 10^{-4}$ | 0.589 |

Practical upper limit and lower detection limits of instruments limit the ability of screening approaches. In most studies, the valid range of screening measurements is 10-10,000 ppmv (in some studies the upper limit is 100,000 ppmv). "Pegged source" and "default zero" factors were developed to work around these limitations (**Table S20**).

If the screening value is reported at the lower limit of the device (10 ppmv), this means that the concentration in the air is at or below the minimum detection limit of the device and the "default zero" emissions factor is used. The default zero emissions factor is used instead of a true "0" for sources screened at the lower limit of the device to recognize that some small leaks will screen below 10 ppm and should not be counted as truly 0 leakage. If the screening concentration is higher than the upper limit of the device, it will report the upper limit value (i.e., 10,000 ppmv in most studies) and the measurement is regarded as "pegged". "Pegged source" factors were developed in the EPA Protocol Document based upon quantified emissions measurements. Like the correlation equations, in order to boost sample size, the pegged factors are based upon data aggregated across the entire petroleum industry and across all service categories (n = 445). These pegged factors are meant to represent all leaks that result in larger than top-end ppmv measurements.

A second key difference between the GHGI derived emissions factors and our study then is the use of pegged source factors. Whereas our study uses only direct measurements, the GHGI applies an average pegged factor based on previously measured data. We attempt to make a

comparison between the GHGI pegged factors and our emissions measurements > 10,000 ppmv in section 5.2.5.

**Table S20: Default zero and pegged emissions factors for various components (data from the GRI report** [41]**)**

| Component type | Default Zero Factor [lb THC/day] | Pegged Factor [lb THC/day] |
|---|---|---|
| Connector | 3.97 x 10-4 | 1.48 |
| Flange | 1.64 x 10-5 | 4.50 |
| Open-ended Line | 1.06 x 10-4 | 1.59 |
| Pump Seal | 1.27 x 10-3 | 3.92 |
| Vale | 4.13 x 10-4 | 3.39 |
| Other | 2.12 x 10-4 | 3.86 |

A final difference to note between our study and the GHGI is the use of population emission factors versus "leaker" emission factors (these approaches are described in greater detail in the EPA Protocol document [5]). Our study essentially takes a "leaker" emission factor approach, with units of kilogram per day per number of emitting components. As discussed in section 2.2.4, screening data is used to define "leakers" and "non-leakers" according to a pre-defined threshold (500 ppmv, or optical gas imaging identification). When calculating total emissions, a random subset of components are designated as "leakers", with a probability defined by the "fraction of components emitting" found in field campaigns that include both emissions measurements and component counts.

This contrasts with the population emission factor approach taken by the GHGI. The population emission factor *(*units of kilogram per day per individual source*)* is the average across the population of components, including both leakers and non-leakers. To calculate population emission factors, we divide the total leakage across all components by the total number of potential leak sources. Because the population emission factor represents the average emissions across all components, explicitly specifying the fraction leaking value is not necessary. Rather, population emission factors simply are multiplied by component counts.

The general equation for population emission factors is as follows,

$$EF_{pop} = \frac{0.454 \cdot Y_{C1} \cdot \left(n_{nl} \cdot \mathrm{DZF} + \sum_{i=1}^{n_l} a \cdot (\mathrm{ISV})^b + n_e \cdot \mathrm{PSF}\right)}{n_{nl} + n_l + n_e}$$

Here, screening data (*ISV*, units of ppmv) is converted to mass of total hydrocarbon using correlation equations, default zero factors (*DZF*), and pegged source factors (PSF) (see **Table S19** and **Table S20**). In converting from mass of total hydrocarbon to mass $CH_4$, we apply mass fractions ($Y_{C1}$). Mass of $CH_4$ is converted to a population emissions factor ($EF_{pop}$, units $lbCH_4$/component/d) by dividing by total components screened which is the sum of components screened by non-emitting ($n_{nl}$), the sum of components emitting ($n_l$), and the sum of components pegged ($n_e$).

It is important to note here that API 4598 and Star Environmental themselves report component-level emission factors. However, the GRI report and API 4638 do not use these directly reported values. Rather, the GRI report and API 4638 assemble the data collected in these studies and conduct a slightly modified analysis.

For additional details on API 4598 and the Star Environmental reports see section 6.

### *5.2.3. Summary of EPA GHGI emission factors*

Before reconstructing emission factor distributions, we reconstruct average emission factors from the GHGI data. We reconstruct the average equipment-level emission factors calculated in the GRI report and API 4698 [41], [42], and subsequently used by the EPA GHGI by summing the emission factors of individual components according to estimated counts of components per piece of equipment. (**Table S21**). For NG systems, the component-level emission factors and component counts referenced in **Table S21** are directly as reported (with the appropriate unit conversion) in the GRI report [41]. For petroleum systems, the GHGI references API publication 4638 [42] for component-level emission factors. Component counts are given directly in the GHGI data source documentation, based on the "consensus of an industry review panel" [2].

**Table S21: Summary of GHGI equipment-level emission factors based on underlying 1990s studies** [41]**. Equipment-level emission factors are calculated as the product of component-level emission factors (population emissions factors, or average across both leaking and non-leaking components) multiplied by the corresponding component count, summed across all components. The underlying studies supporting the GHGI report separate equipment-level emission factors for Western US gas, Eastern US gas, light oil, and heavy oil systems. Note that the numbers for Eastern Gas Wells are as reported in the GRI report, therefore are slightly different from what is reported in the Star Environmental study.**

| | | Western US gas systems | | | Eastern US gas systems | | | Light oil systems | | | Heavy oil systems | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Component EF kg/comp/day | Comp count | Equipment EF kg/eq/day | Component EF kg/comp/day | Comp count | Equipment EF kg/eq/day | Component EF kg/comp/day | Comp count | Equipment EF kg/eq/day | Component EF kg/comp/day | Comp count | Equipment EF kg/eq/day |
| Gas or oil well | Valve | 0.044 | 11 | 0.701 | 0.010 | 8 | 0.137 | 0.036 | 5 | 0.320 | 1.88E-04 | 5 | 0.002 |
| | Flange | | | | | | | 0.002 | 10 | | 8.98E-06 | 10 | |
| | Connection | 0.006 | 36 | | 0.001 | 38 | | 0.003 | 4 | | 1.71E-04 | 4 | |
| | OEL | 0.011 | 1 | | 0.022 | 0.5 | | | | | | | |
| | Polished rod | | | | | | | ? | 1 | | ? | 1 | |
| Separators | Valve | 0.044 | 34 | 2.346 | 0.010 | 1 | 0.017 | 0.036 | 6 | 0.267 | 1.88E-04 | 6 | 0.003 |
| | Flange | | | | | | | 0.002 | 12 | | 8.98E-06 | 12 | |
| | Connection | 0.006 | 106 | | 0.001 | 6 | | 0.003 | 10 | | 1.71E-04 | 10 | |
| | OEL | 0.011 | 6 | | | | | | | | | | |
| | PRV | 0.070 | 2 | | | | | | | | | | |
| Heaters | Valve | 0.044 | 14 | 1.110 | 0.010 | 14 | 0.273 | 0.036 | 8 | 0.369 | | | |
| | Flange | | | | | | | 0.002 | 12 | | | | |
| | Connection | 0.006 | 65 | | 0.001 | 65 | | 0.003 | 20 | | | | |
| | OEL | 0.011 | 2 | | 0.022 | 2 | | | | | | | |
| | PRV | 0.070 | 1 | | 0.015 | 1 | | | | | | | |
| Dehydrators | Valve | 0.044 | 24 | 1.752 | 0.010 | 24 | 0.418 | | | | | | |
| | Connection | 0.006 | 90 | | 0.001 | 90 | | | | | | | |
| | OEL | 0.011 | 2 | | 0.022 | 2 | | | | | | | |
| | PRV | 0.070 | 2 | | 0.015 | 2 | | | | | | | |
| Meter/piping | Valve | 0.044 | 14 | 1.017 | 0.010 | 12 | 0.173 | | | | | | |
| | Connection | 0.006 | 51 | | 0.001 | 45 | | | | | | | |
| | OEL | 0.011 | 1 | | | | | | | | | | |
| | PRV | 0.070 | 1 | | | | | | | | | | |
| Gathering compressor | Valve | 0.044 | 73 | 5.149 | 0.010 | 12 | 0.233 | | | | | | |
| | Connection | 0.006 | 179 | | 0.001 | 57 | | | | | | | |
| | OEL | 0.011 | 3 | | 0.022 | 2 | | | | | | | |
| | PRV | 0.070 | 4 | | | | | | | | | | |
| | comp seal | 0.125 | 4 | | | | | | | | | | |
| Header | Valve | | | | | | | 0.036 | 5 | 0.209 | 1.88E-04 | 5 | 0.002 |
| | Flange | | | | | | | 0.002 | 10 | | 8.98E-06 | 10 | |
| | Connector | | | | | | | 0.003 | 4 | | 1.71E-04 | 4 | |

### *5.2.4. Comparing re-analyzed component-level emission factors*

Using the data presented from the underlying studies in the previous section, we can develop component-level emissions distributions for comparison with distributions generated in this study. Here, we first describe how these distributions were developed. Next, using these component-level emissions data, we attempt to re-calculate the component-level emission factors reported by the GHGI's underlying studies.

We first analyze the screening data in API 4598 [3] and Star Environmental [4] and follow the methods outlined in subsections 4.2.2 – 4.2.3. In API 4598, we scanned and tabulated screening concentrations from Appendix C.

Unfortunately, it was not possible to re-derive the component-level emission factors in the Star Environmental dataset. This was for two reasons. First, in the Star Environmental emissions quantification data (provided in Appendix F, [4]), information is not provided on components measured. Therefore, quantified leaks cannot be connected to the screening values contained in Appendix E. Second, the Eastern dataset does not report how they assigned leak volumes to the 81 instrument readings > 10,000 ppmv which were not quantified with the Hi Flow sampler. Therefore, the remainder of this section will focus on re-generated emission factors from API 4598.

Several issues arise in regenerating component-level emission factors from the API 4598 data. First, it is unclear which correlation equations, pegged source factors, and default zero factors were applied for pressure relief valves and compressor seals. No equation and factors matching these component names are available in the EPA Protocol Document [5] or GHGI. To generate a first order estimate, we apply equations and factors under the "other" category. Second, classification of "threaded connections" and "flanges" is not consistent across the GHGI's underlying studies. After presenting our results, we will investigate uncertainty in connector/flange classification.

After completing our re-analysis of the API 4598 data, we can compare our re-analyzed results with reported emission factors in the GHGI. For both natural gas systems and petroleum systems there is significant variability in alignment with our computed component-level emission factors based on the same data GHGI cites (**Table S22**). Valves compare well, with absolute variation

≤6% across sources. For other component classes, although emission factors match the correct order of magnitude, alignment is less precise. There are several possibilities for the source of misalignment. In general, although GRI and the EPA Protocol Document recalculate emission factors based upon the original API 4598 dataset, only a limited amount of information is provided on how the data is used, therefore, it was not possible to perfectly reconstruct emission factors.

**Table S22: Reconstructed component-level emission factors compared with those reported in the GRI Report** [41] **and the EPA Protocol document** [5]**. The reconstructed emission factors match the reported values within the correct order of magnitude, which is close considering discrepancies with emission factors from this study's model.**

| Component | Reported emission factor [$kgCH_4$/component/day] | Reconstructed emission factor [$kgCH_4$/component/day] | Percent difference [%] |
|---|---|---|---|
| Gas production sites[1] | | | |
| Connector | 6.01E-03 | 4.71E-03 | -22% |
| Valve | 4.40E-02 | 4.52E-02 | 3% |
| Open-ended line | 1.13E-02 | 1.25E-02 | 10% |
| Pressure relief | 7.02E-02 | 2.57E-02 | -63% |
| Compressor Seal | 1.25E-01 | 8.58E-02 | -31% |
| Light oil sites[2] | | | |
| Connector[3] | 3.08E-03 | 2.51E-03 | -19% |
| Flange[3] | 1.62E-03 | 2.97E-03 | 84% |
| Valve | 3.67E-02 | 3.41E-02 | -7% |
| Open-ended line | 2.06E-02 | 3.30E-02 | 61% |
| Heavy oil sites[2] | | | |
| Connector[3] | 1.70E-04 | 1.11E-04 | -35% |
| Flange[3] | 8.82E-06 | 7.37E-06 | -16% |
| Valve | 1.90E-04 | 1.91E-04 | 1% |
| Open-ended line | 3.17E-03 | 3.27E-03 | 3% |

[1]Reported emissions factor from Hummel et al. (1996) [41]
[2]Reported emissions factor from EPA (1995) "Protocol document" [5]
[3]Recalculated iteratively assigning connectors and flanges

As it was mentioned, for natural gas system emission factors the classification of "threaded connections" and "flanges" is not consistent across studies. In the EPA Protocol document, separate correlation equations and pegged source factors are provided for these two components. However, in the API 4598 source data, both "threaded connections" and "flanges" are classified as connectors. In the GRI report, they describe how a "combined component emission factor for

flanges/connectors was calculated" but little information is given on how this is accomplished [41]. The EPA Protocol Document derives an emissions factor for flanges by assuming (based on gas plant measurements in API 4615, [40]) that 71% of all "connectors" measured were threaded connections while the remainder were flanges. Unfortunately, neither the EPA Protocol Document or API 4615 specify which measurements are assigned as connectors and which are assigned as flanges.

To test the sensitivity of the emission factor to how the measurements are assigned, we iteratively re-shuffle the measurements and assign connectors and flanges using the EPA Protocol document's 71% share of "threaded connections". The results demonstrate a high sensitivity to re-shuffling for light oil but not heavy oil (**Figure S14**). This is because for light oil, 356 leaks were measured at connectors, while for heavy oil only 4 leaks were measured (with relatively small variations in emissions rates). It should be noted that although API 4615 notes how many leakers were classified as connectors versus flanges, they do not specify the distribution of non-leakers. We assume a 50% split in our main analysis.

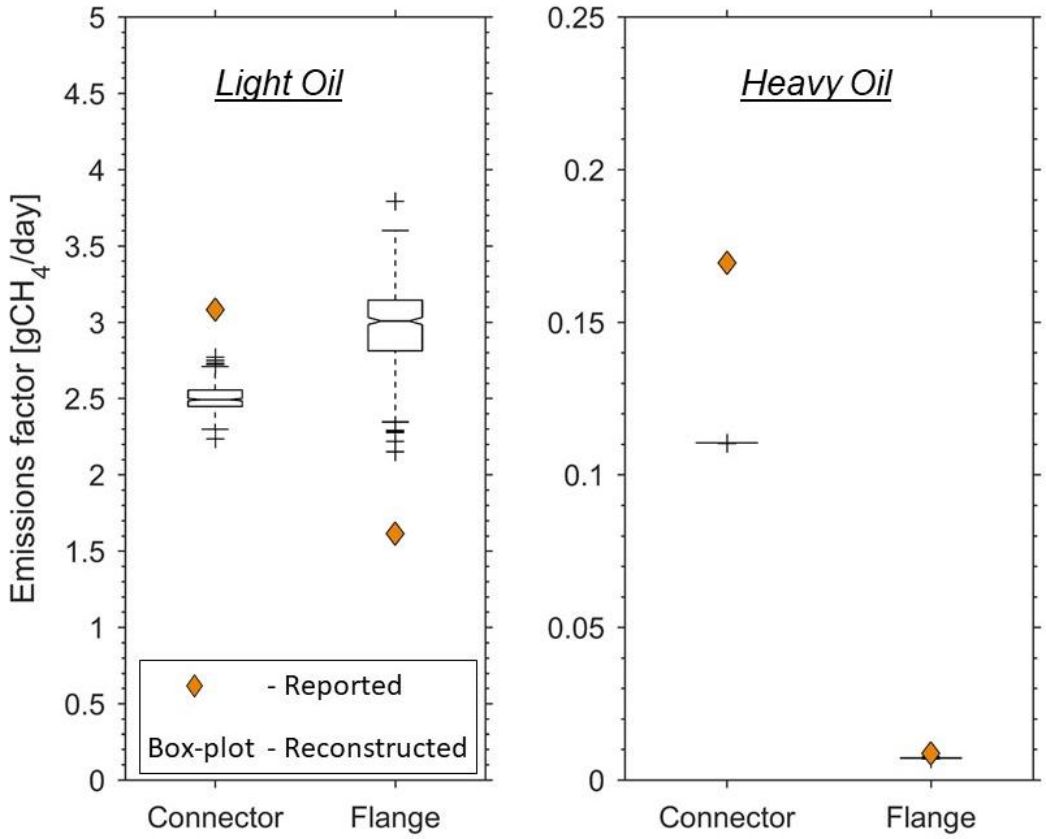


**Figure S14: Comparisons of the range of possible component-level connector and flange emission factors with reported emission factors (represented by orange diamonds). Box plots represent the range of possible emissions factors determined by reshuffling measurements and randomly assigning connectors and flanges for light oil (500 realizations) and heavy oil (20 realizations)**

### *5.2.5. Comparison of emission factors cited by the GHGI with emission factors generated in this study*

After digitization and re-engineering of the GHGI methods, we can compare the distributions of the resulting component-level estimates with our dataset. In this section we first compare the distributions. As it is noted in the main text, a key result is the striking difference in component level emissions measurements. This could either be the result of fundamentally different O&NG systems, or it could be the result of under-sampling or the use of constant pegged source factors to represent the upper tail of emission values. We investigate this question in this section with an iterative Monte Carlo test of sample size.

As described in more detail in SI section 3.2.4, our dataset is split at a threshold screening concentration of 10,000 ppmv. This was done because different screening technologies will sample different parts of the emissions distribution. It must be taken care that emissions frequency and emissions measurements are not confused between technologies. A similar distinction can be made with the underlying GHGI datasets: Emissions ≥ 10,000 ppmv are assigned pegged source factors and emissions < 10,000 ppmv are based on correlation equations. For this section, rather than simply comparing with the pegged source factor, we present the full distribution of emissions measurements used to generate the pegged source factor. Recall that pegged source factors were developed based on quantified emissions measurements from refinery, marketing terminal, and oil and gas production facility (measurements digitized from the EPA Protocol document Appendix C Attachment 2, [5]).

**Figure S15** compares distributions separately according to the 10,000 ppmv threshold. We also distinguish between the API 4598 dataset ([3], Western gas and petroleum systems, **Figure S15a**) and the Star Environmental dataset ([4], Eastern gas systems, **Figure S15b**). On average, our dataset has much larger population-level component leakage estimate than both the Western and Eastern datasets. This issue is discussed in greater detail in the main manuscript. The second point of comparison is between our leaker data at < 10,000 ppmv and correlation equation-generated leakage factors for both Western gas and petroleum systems (**Figure S15c**) and Eastern gas systems (**Figure S15d**).

**Figure S16** contains a component-by-component comparison. Recall that we were not able to do a component by component breakdown from the Star Environmental Eastern dataset, therefore data here is only presented for API 4598 (Western gas systems and petroleum systems). Here, we do not present the underlying data for pegged source factors. The pegged source factors in API 4598 probability density functions can be easily spotted as the tall bars near the upper end of the emissions magnitudes.

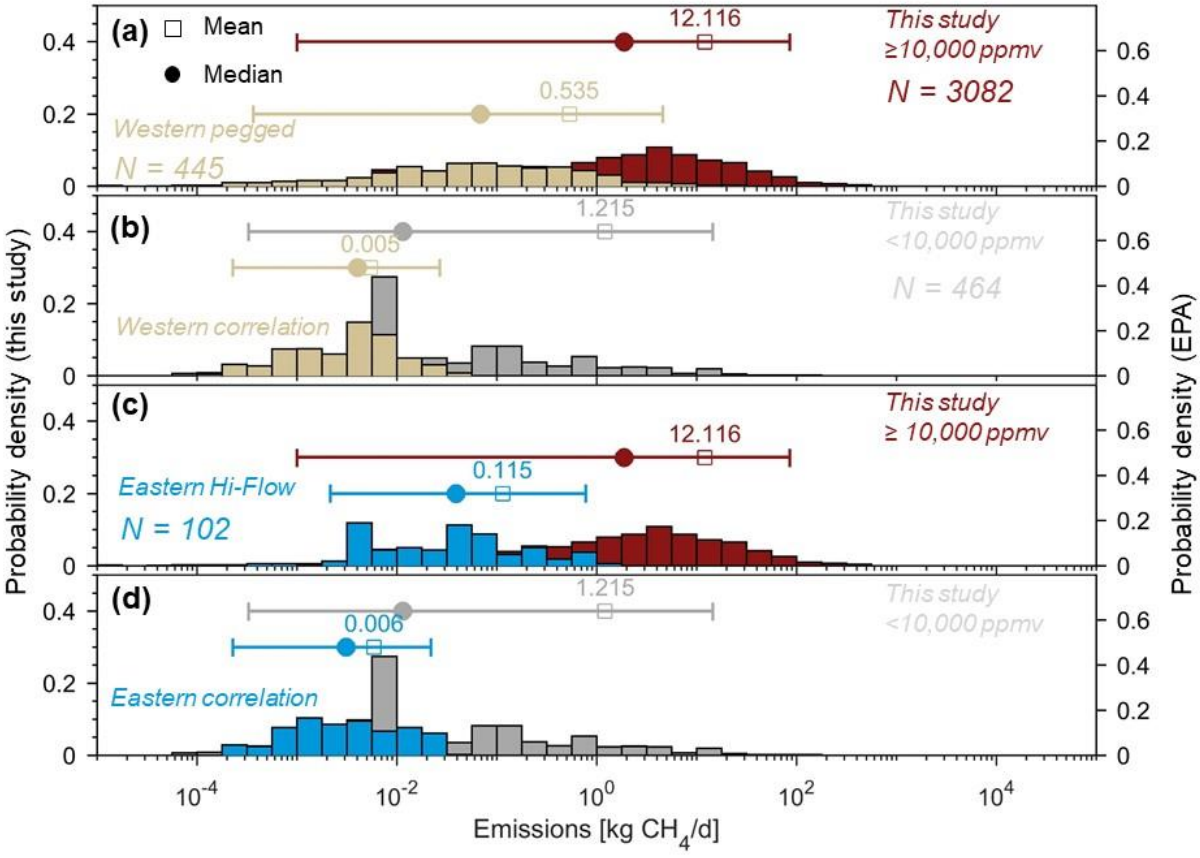


**Figure S15: Component-level emissions aggregated across all production-segment sources comparing the Western US and petroleum data set (API 4598)** [3] **(a and b) and the Eastern US data set (Star Environmental)** [4] **(c and d) with our dataset. Western and Eastern datasets are disaggregated into component-level emissions underlying pegged factors for comparison with our dataset ≥ 10,000 ppmv (a and c) and emissions generated from correlation equations (corr.) are compared with our dataset < 10,000 ppmv (b and d). Rather than comparing with the pegged source factors (a single number), in panel (a) we compare our dataset with the underlying emissions measurements used in developing the pegged source factors (digitized from EPA Protocol document Appendix C Attachment 2,** [5]**). Horizontal bars span the 5th and 95th percentile. Note that the histogram scale for this study's dataset is on the left hand side of the plots, and the scale for the GHGI datasets is on the right hand side of the plots. Note the log scale of emissions with the implication that discrepancies span 1-3 orders of magnitude.**

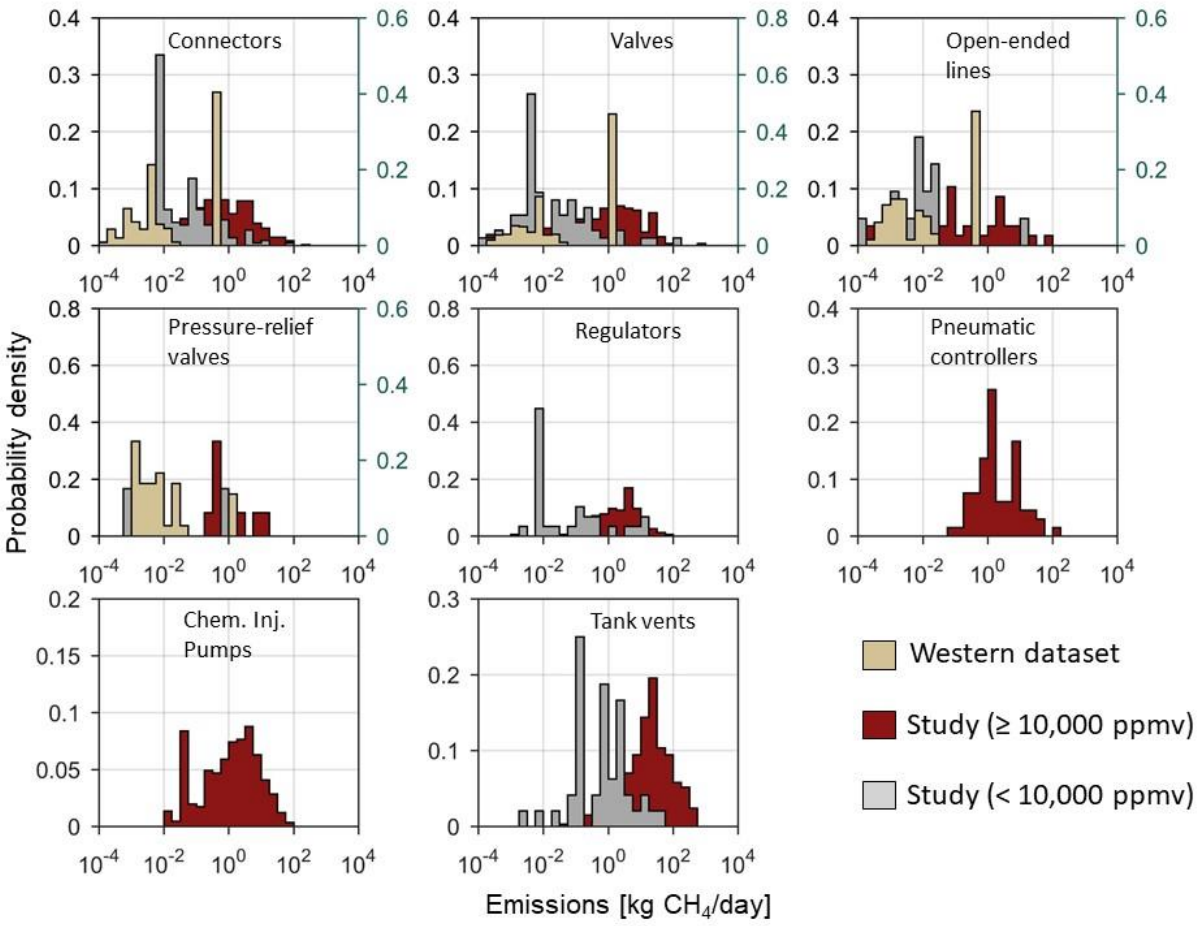


**Figure S16: Disaggregated probability distributions of component-level emissions comparing the Western US (API 4589) dataset with our dataset. Note that the histogram scale for this study's dataset is on the left hand side of the plots, and the scale for the API 4598 is on the right hand side of the plots. Note the log scale of emissions with the implication that discrepancies span 1-3 orders of magnitude.**

Both the pegged source factors generated in the EPA Protocol document and high-flow sampler data in the Eastern gas dataset have smaller sample sizes compared to our dataset (n = 445 and n = 102, respectively, versus n = 2714 in our dataset). Could an insufficient sample size explain the difference in magnitude of component-level emission factors between our studies? As described in detail in Brandt et al. [22], small sample sizes can miss low-frequency super-emitters, resulting in low emissions. The lower range of the sample mean increases as sample size increases and as super-emitters are increasingly captured. To test this this theory of insufficient sample size (or, in other words, if EPA's small averages are due to a small sample which misses super-emitters), we perform a Monte Carlo exercise.

First, we filter our dataset into connectors, valves, and open-ended lines (because these are clearly marked in our datasets and [25]). Next, we resample (without replacement) subsets of different sizes of our full dataset. The mean of our sample set is calculated for each subset. In this way, we test how sample size affects component-level emission factors (**Figure S17**). This exercise is performed 500 times (multiple colored lines in **Figure S17**). By comparing the probability envelopes generated with this resampling exercise with emissions factors from the EPA, we can estimate the likelihood of sample size explaining the discrepancy.

The small sample sizes of Star Environmental (65 connections, 28 valves, 7 open-ended lines) might have resulted in finding lower component-level emission factors compared to a larger dataset. However, when we compare actual sample sizes and mean emissions rates from Star Environmental (orange diamonds in **Figure S17**) to our envelopes generated via Monte Carlo resampling, we see that the Star Environmental mean emissions rates are very low even accounting for their small sample size. In fact, it is very difficult to recreate emission factors this low by sampling from our dataset. Further, even though pegged source factors in the EPA Protocol document are sourced from a larger dataset, the emission factors still fall outside of the expected range demonstrated by the 95% uncertainty envelope generated with resampling from our dataset.

We can think of three options to explain this discrepancy: (1) there is sampling bias in the original collection process; (2) the two populations being sampled (original 1990s studies and our studies) are fundamentally different due to differences in equipment type, age, or complexity (e.g., most O&NG is now produced from unconventional shale formations, where it wasn't in the original GRI study); or (3) there is a time trend in emissions rates between the 1990s and today.

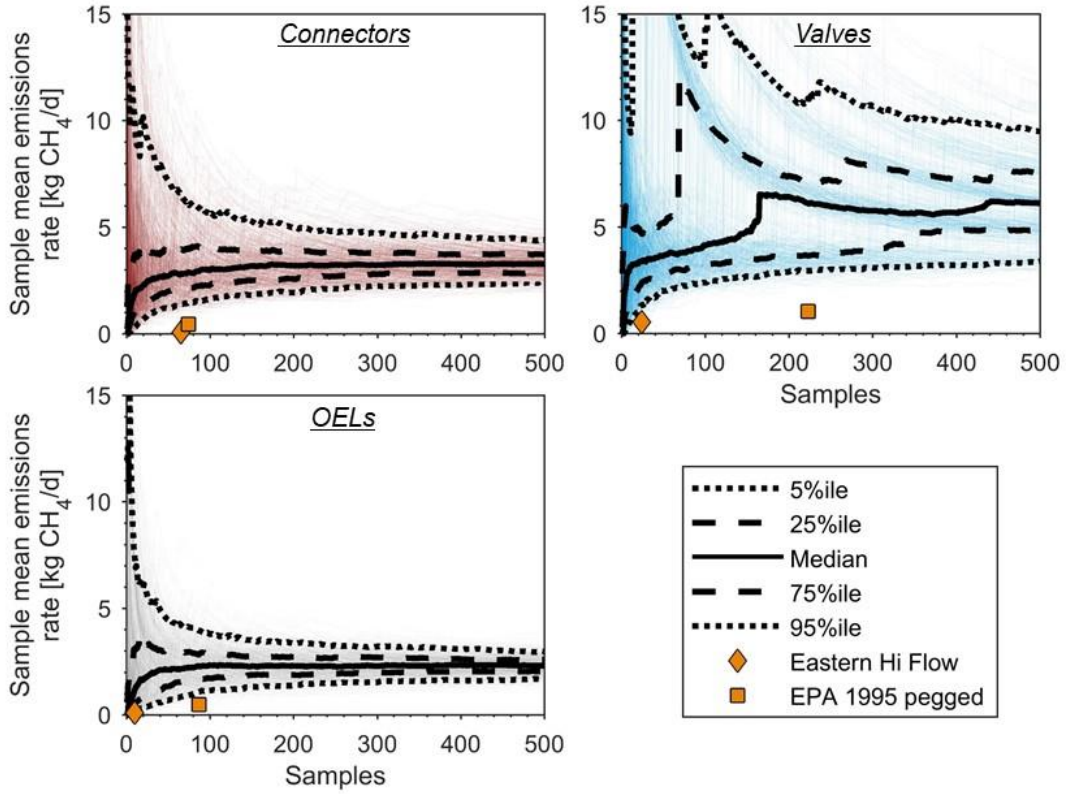


**Figure S17: Realizations of sample mean emission rate versus sample size for various components derived by resampling our modern dataset. By comparing the probability envelopes generated with this resampling exercise with emission factors from the EPA** [4], [5]**, we can estimate the likelihood of sample size explaining the discrepancy. This exercise demonstrates that the odds of EPA emission factors coming from a similar distribution as ours are very small.**

### *5.2.6. Emission factor decompositions*

In the main text we presented a decomposition of equipment leakage emission factors for gas wells in Western natural gas systems. Below we present additional decompositions for both Eastern and Western systems and various equipment.

One source of deviation not explored in the main text is related to the fact that equipment-level emission factors for NG systems in the GHGI are a region-weighted combination of Western emission factors and Eastern emission factors. Component-level emission factors in the Eastern data (e.g., **Figure S18**) are significantly smaller compared to both this study and the EPA Western US data and are derived from an even smaller sample from the 1990s (~100 quantified leaks).

Since these measurements were made, NG production in the Eastern US has grown from <5% of US domestic production to ~28% (**Figure S31**).

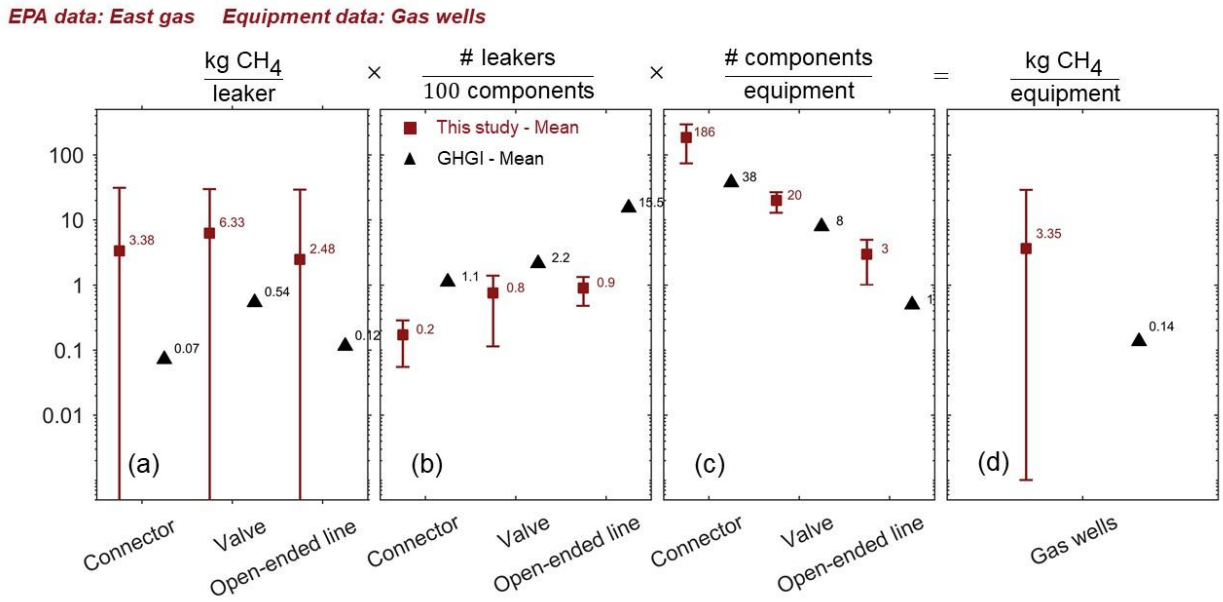


**Figure S18: Decomposition of GHGI equipment-level emission factor for gas wells into constituent parts. Equipment-level emission factors for gas systems are a function of data for both Western systems (API 4598,** [40]**) and Eastern gas systems (Star Environmental,** [4]**). Here, we only show constituent data for Eastern gas systems.**

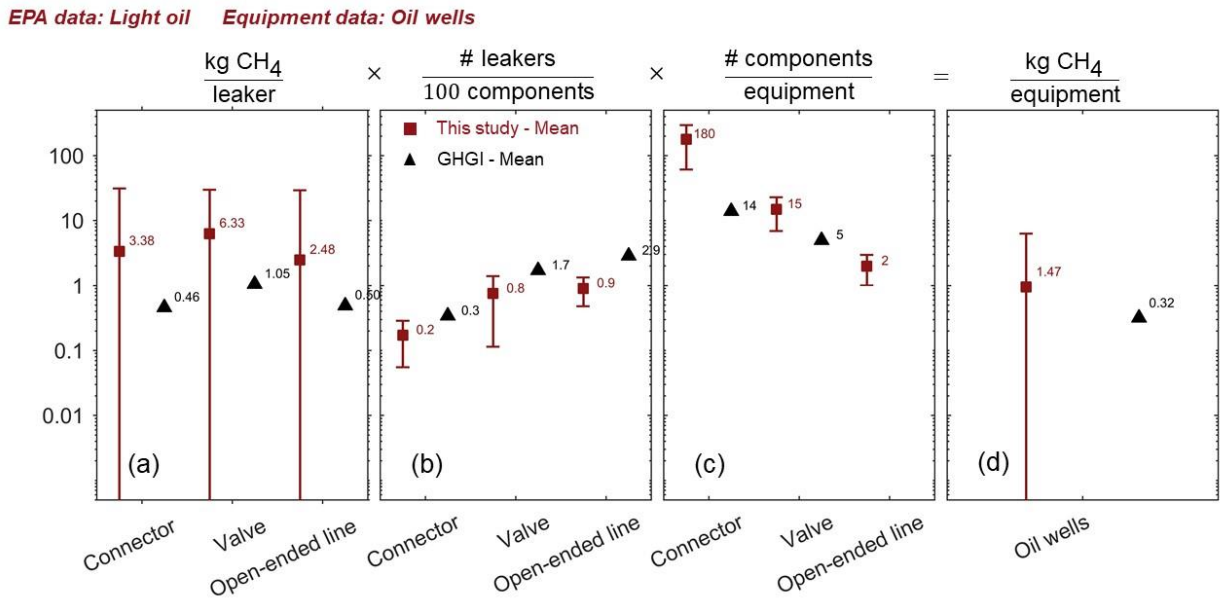


**Figure S19: Decomposition of GHGI equipment-level emission factor for oil wells into constituent parts. Equipment-level emission factors for oil systems are a function of data for both light oil systems and heavy oil systems (both from API 4598,** [40]**). Here, we only show constituent data for light oil systems.**

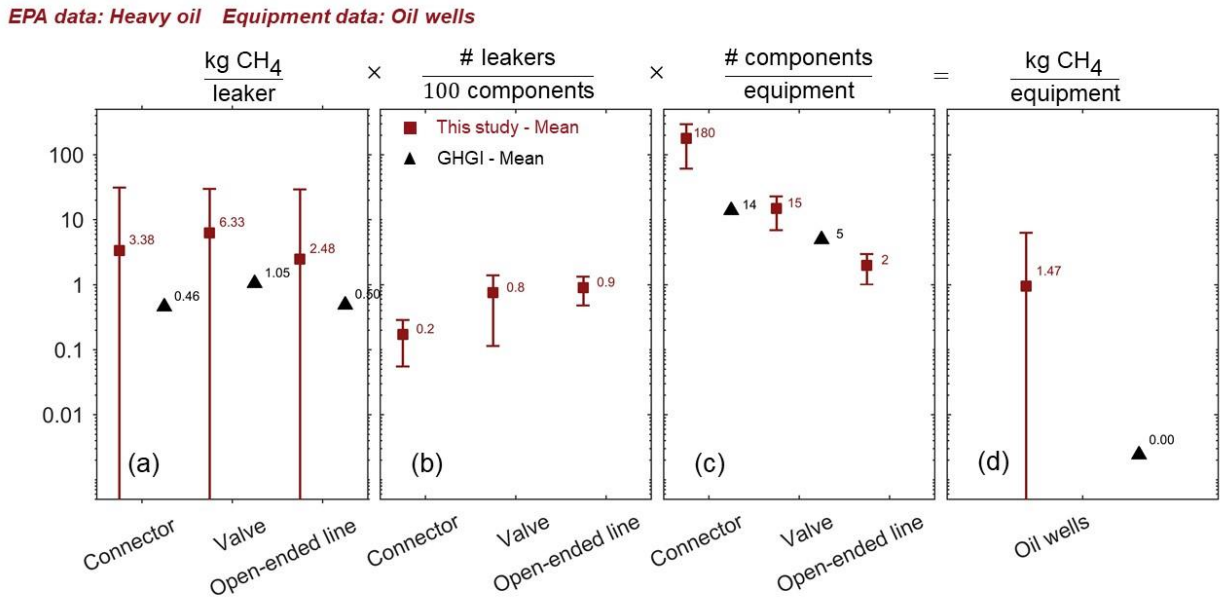


**Figure S20: Decomposition of GHGI equipment-level emission factor for oil wells into constituent parts. Equipment-level emission factors for oil systems are a function of data for both light oil systems and heavy oil systems (both from API 4598,** [40]**). Here, we only show constituent data for heavy oil systems.**

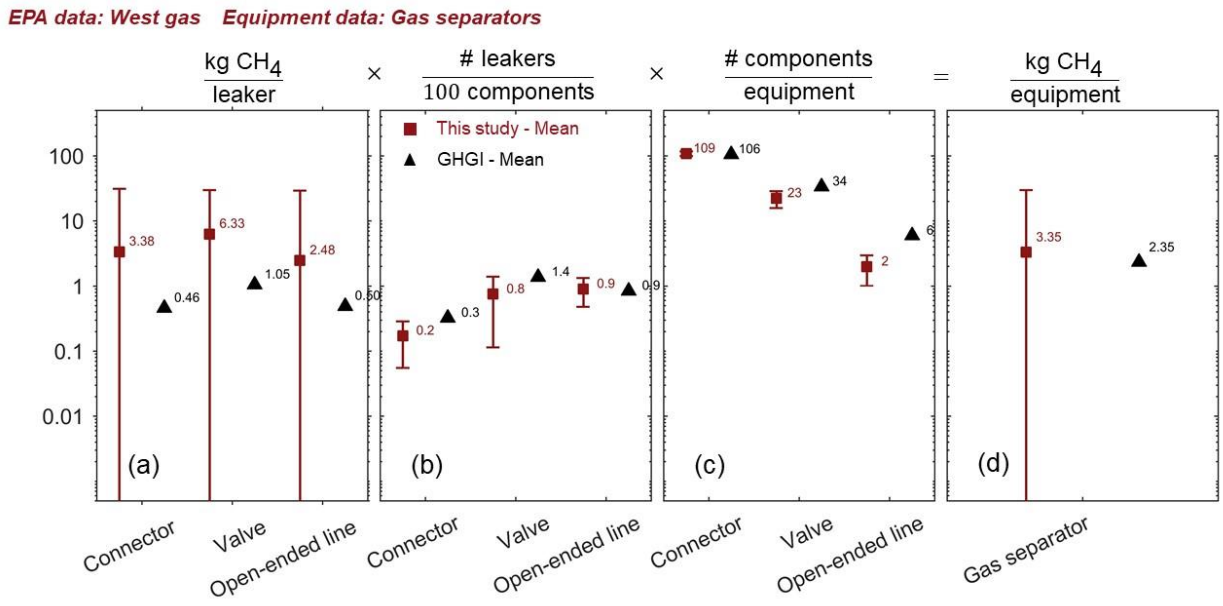


**Figure S21: Decomposition of GHGI equipment-level emission factor for gas separators into constituent parts. Equipment-level emission factors for gas systems are a function of data for both Western systems (API 4598,** [40]**) and Eastern gas systems (Star Environmental,** [4]**). Here, we only show constituent data for Western gas systems.**

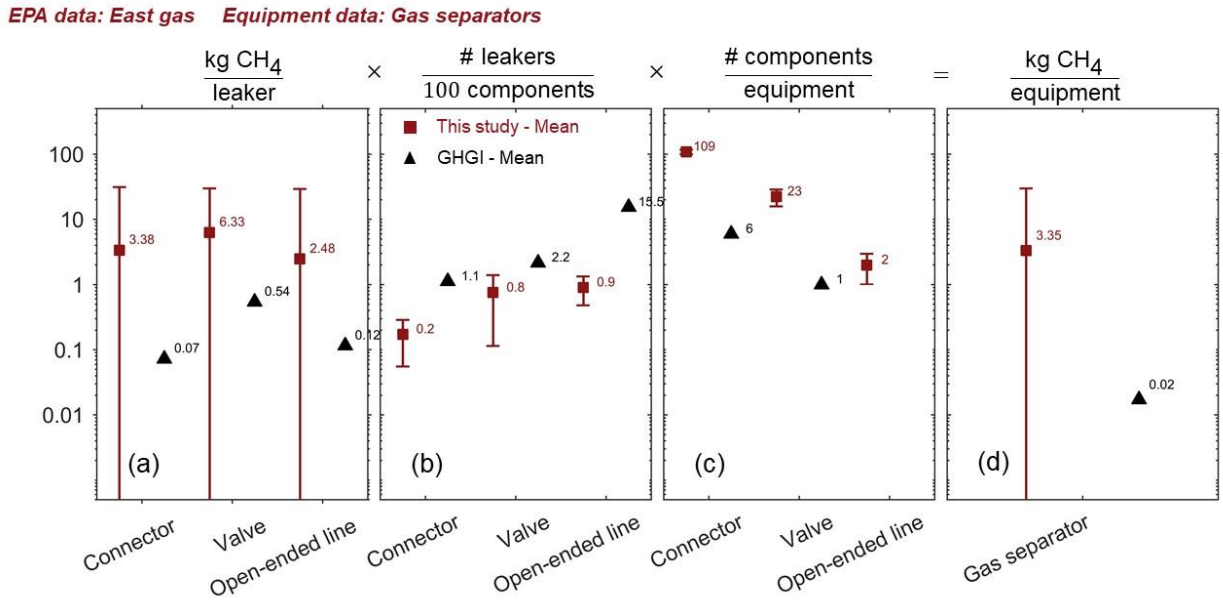


**Figure S22: Decomposition of GHGI equipment-level emission factor for gas separators into constituent parts. Equipment-level emission factors for gas systems are a function of data for both Western systems (API 4598,** [40]**) and Eastern gas systems (Star Environmental,** [4]**). Here, we only show constituent data for Eastern gas systems.**

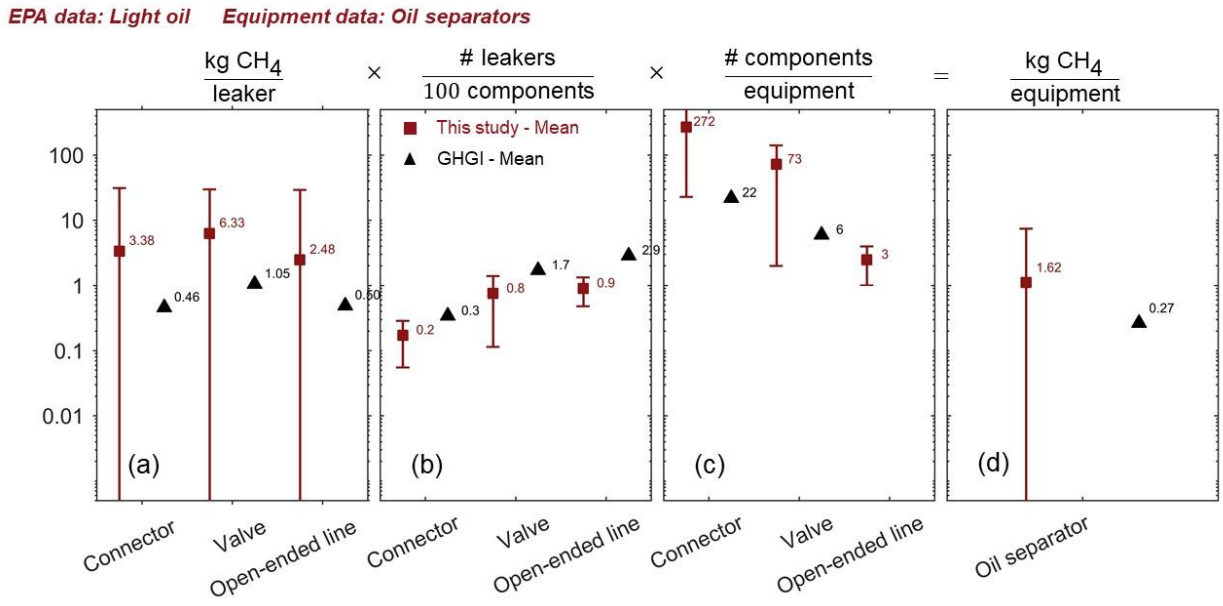


**Figure S23: Decomposition of GHGI equipment-level emission factor for oil separators into constituent parts. Equipment-level emission factors for oil systems are a function of data for both light oil systems and heavy oil systems (both from API 4598,** [40]**). Here, we only show constituent data for light oil systems.**

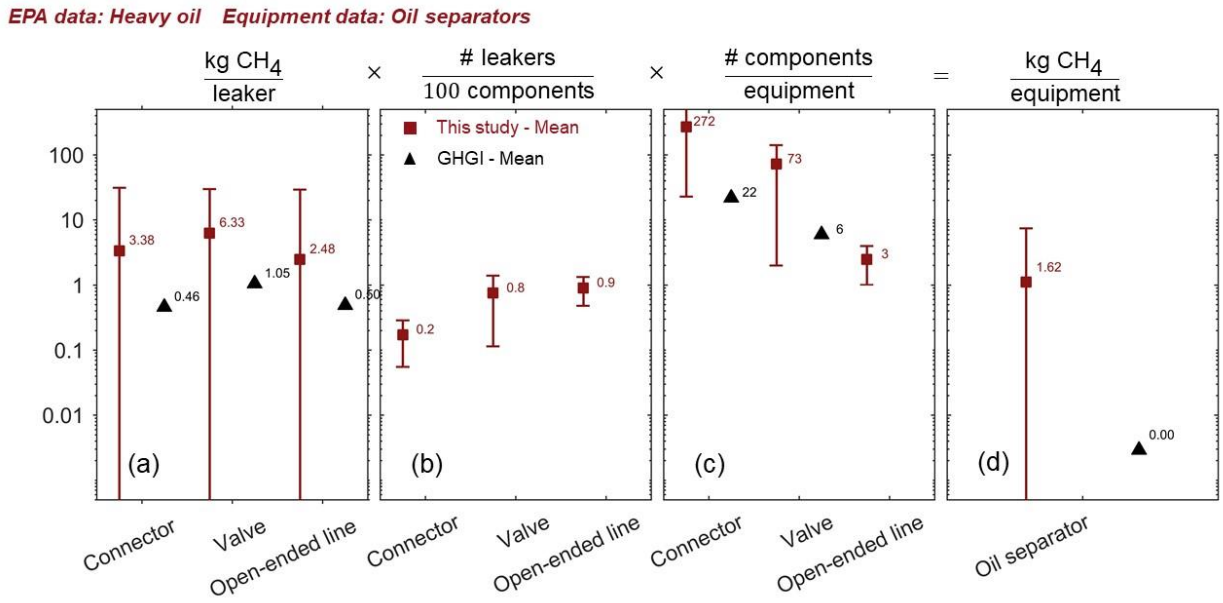


**Figure S24: Decomposition of GHGI equipment-level emission factor for oil separators into constituent parts. Equipment-level emission factors for oil systems are a function of data for both light oil systems and heavy oil systems (both from API 4598,** [40]**). Here, we only show constituent data for heavy oil systems.**

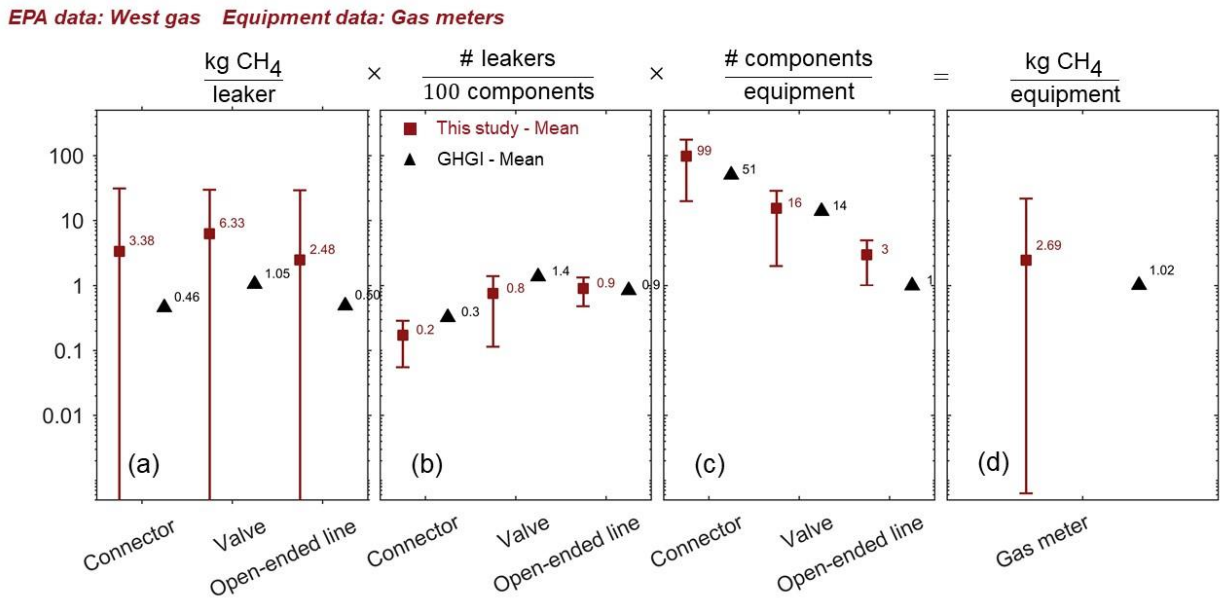


**Figure S25: Decomposition of GHGI equipment-level emission factor for gas meters into constituent parts. Equipment-level emission factors for gas systems are a function of data for both Western systems (API 4598,** [40]**) and Eastern gas systems (Star Environmental,** [4]**). Here, we only show constituent data for Western gas systems.**

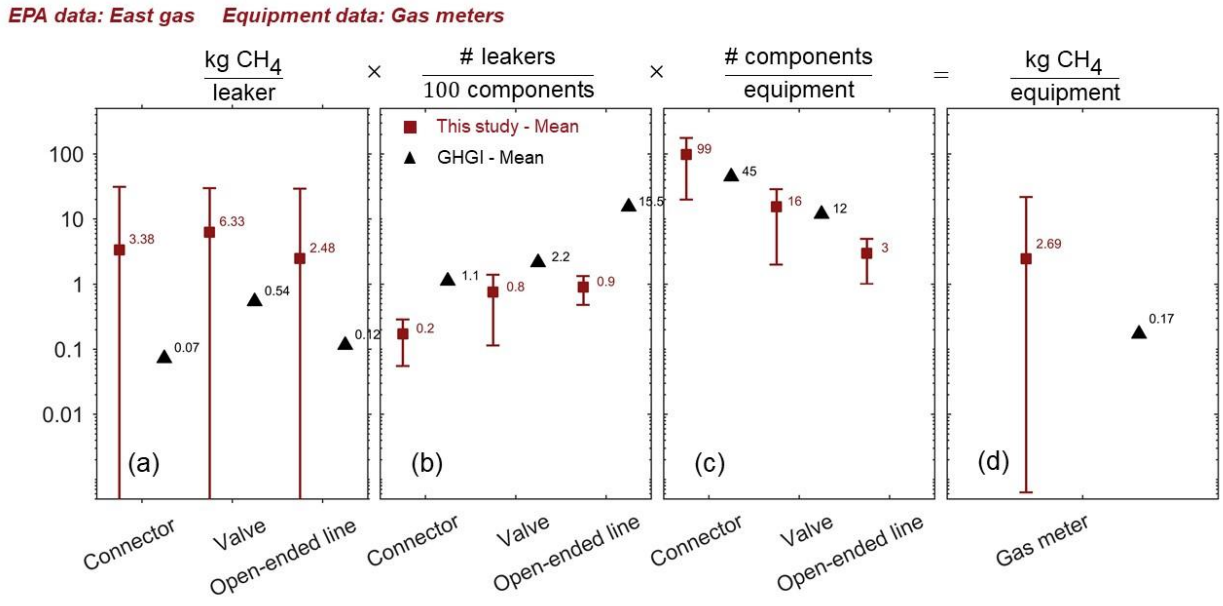


**Figure S26: Decomposition of GHGI equipment-level emission factor for gas meters into constituent parts. Equipment-level emission factors for gas systems are a function of data for both Western systems (API 4598,** [40]**) and Eastern gas systems (Star Environmental,** [4]**). Here, we only show constituent data for Eastern gas systems**

## 5.3. Reconstructing GHGI emissions factor for storage tanks

Like our analysis of equipment leakage data, the goal of this section is to reconstruct the GHGI dataset for tank emissions and make a comparison with the data for this study. First, we describe the underlying data sources for the GHGI and how data are converted to emission factors. Second, we reconstruct the GHGI emission factors in two ways. We apply one method to verify that our reconstructed emissions factors match those in the GHGI, and another separate method for a more consistent comparison with storage tank emission factors in this study. A complete description of our study's formulation of storage tank emissions can be found in section 3.3.2 (and summarized in **Figure S8** and **S9**).

### *5.3.1. Deriving emission factors – General approach*

In the 2017 Greenhouse Gas Inventory (GHGI), the EPA revised its approach to calculating $CH_4$ emissions from crude and condensate storage tanks [21]. Prior to 2017, emission factors were "developed from default sample runs available through E&P Tank" [21], [54]. Since 2017, the EPA has implemented an approach leveraging data from the Greenhouse Gas Reporting Program (GHGRP). However, it must be emphasized that emission factors through the GHGRP are still developed based on software programs such as E&P Tank (see further description below), only since 2017 the simulations are based on operator data (e.g., pressure, temperatures, throughput). Therefore, in contrast to our emission factors which are based on direct measurements of emissions, the GHGRP approach is based on simulated emissions volumes.

The GHGRP is a program administered by EPA which collects greenhouse gas data from high emitting industrial facilities across multiple industry segments. Reporting requirements for petroleum and natural gas systems are described in the Code of Federal Regulations (CFR) Title 40 Part 98 Subpart W, which states that facilities emitting greater than 25,000 metric tonnes of $CO_2$ equivalent must report data to GHGRP [6]. GHGRP reporting requirements and emissions calculations differ for tanks storing throughput from wells producing at less than 10 bbl/d (referred to as small tanks) and tanks storing throughput from wells producing at greater than or equal to 10 bbl/d (referred to as large tanks).

In the current approach (since 2017), the GHGRP applies separate emissions calculation methods for large versus small tanks. Operators have a choice between calculation approaches 1 and 2 for large tanks. Operators apply calculation approach 3 for small tanks.

- Calculation approach 1: Use a software program such as API E&P Tank or AspenTech HYSYS [54], [55].
- Calculation approach 2: Assume all $CH_4$ in liquid is emitted.
- Calculation approach 3: Emissions are calculated by multiplying a population emission factor by the number of wells and applying an average throughput of 2.2 bbl/day.

Within each of these categories (small/large, petroleum/natural gas), the GHGRP subcategorizes tanks as follows:

- Tanks with vapor recovery units (VRU)
- Tanks with flares
- Tanks venting to the atmosphere

For large tanks only, there is a separate inventory category for "malfunctioning separator dump valves".

The EPA uses data from the GHGRP to calculate storage tanks emission factors for the GHGI. The steps taken by the EPA in processing GHGRP data are reported in EPA [21]. These are also the steps we will use in the next section to reconstruct EPA emission factors. Note that the EPA elected to use a throughput-based approach, where emission factors are calculated per unit of crude throughput. This differs from the approach of this study (for unintentional emissions for thief hatches, PRVs) where emission factors are calculated per unit tank.

Briefly, the steps we take in reproducing GHGI emission factors on a per unit tank basis are as follows:

1) Gather GHGRP simulated data from [26]: Separate GHGRP data tables are available for large tanks and small tanks, respectively. Both tables list data at the sub-basin level.
2) Partition data sets into natural gas and petroleum systems: As in other areas, the EPA reports separate emissions volumes for natural gas systems and petroleum systems. Because natural gas production (and thus, gas-to-oil ratio) is not reported in the GHGRP, the EPA uses the subpart W formation type to partition data between petroleum and natural gas production systems. Data assigned to "high permeability gas", "shale gas", "coal seam", or "other tight reservoir rock" are allocated to natural gas production systems. All other formation types are allocated to petroleum production systems.

3) Partition data sets into tank categories: In addition to product stream, EPA also partitions data based on storage tank class (tanks with VRUs, tanks venting to the atmosphere, tanks with flares). Though emissions and tank counts are already allocated by storage tank class, throughput is only reported by sub-basin. Due to lack of data we assume that if multiple storage tank classes are reported in a single sub-basin, throughput is apportioned evenly proportional to tank counts between the storage tank classes.
4) Sum emissions and throughput: For natural gas systems and petroleum systems and all tank classes, the EPA sums reported emissions (kilotonnes) and liquids throughput (MMbbl).
5) Calculate emission factors, $EF_i$: For natural gas and petroleum systems and for each tank class $i$ ($i$ = VRU, flaring, or venting), the EPA calculates emission factors, $EF_i$, as GHGRP reported emissions, $E_{i,GHGRP}$, divided by GHGRP liquids throughput for each tank class, $Q_{i,GHGRP}$.
6) Calculate total population emissions, $E_{i,pop}$: Because operators are only required to report to GHGRP if the facility emissions exceed a threshold of 25,000 tonnes CO2e/year, GHGRP emissions and throughput totals are not comprehensive and therefore not suitable for direct use in the GHGI. The EPA therefore calculates total population emissions as follows, where $Q_{i,pop}$ is the population level liquids throughput for each tank class $i$:

$$E_{i,tot} = EF_i \times Q_{i,pop}$$

To extrapolate GHGRP data to a national estimate, EPA must estimate $Q_{i,pop}$.

$$Q_{i,pop} = Q_{tot,pop} \times f_{tanks} \times f_{i,GHGRP}$$

In order to estimates $Q_{i,pop}$ EPA first applies 2015 liquids volumes from the EIA, $Q_{total,pop}$, which are 297 MMbbl and 3442 MMbbl for natural gas and petroleum systems, respectively [21]. Second, we need the fraction sent to tanks, $f_{tanks}$. Based on EPA analysis of GHGRP data (as reported in the 2020 GHGI, [2]), this is 79.4% and 62.7%, for natural gas and petroleum systems, respectively. Finally fraction of throughput by tank class, $f_{i,GHGRP}$, is calculated using activity data described in step 3 as $f_{i,GHGRP} = Q_{i,GHGRP} / Q_{tanks,GHGRP}$, where $Q_{tanks,GHGRP}$ is the total volume of throughput reported in the GHGRP.

### *5.3.2. Reanalysis of average emissions factors*

To reconstruct emission factors, we begin by downloading GHGRP data from the "Envirofacts GHG Customized Search" tool [26] according to the following steps

11. Access EPA custom GHG search site on July 25, 2020. URL: https://www.epa.gov/enviro/greenhouse-gas-customized-search
12. Select "Petroleum and natural gas systems"
13. Select reporting year 2015 and click "Go to step 2"

14. Click on the appropriate table for the subject, “EF_W_ATM_STG_TANKS_CALC1OR2” which pertains to emissions from large storage tanks.
15. Click on step 3: Select Columns button
16. Select all columns
17. Click on "Go to step 4"
18. Do not select any narrowing criteria
19. Click on "output to CSV file"

We conduct the same steps for small tanks, where the table downloaded from Envirofacts is titled “EF_W_ATM_STG_TANKS_CALC3”.

We attempt to reconstruct GHGI emission factors by following the steps described in the previous section. We reconstruct emission factors both on a throughput basis, to match those presented in the GHGI, and on a per-tank basis. We calculated tank basis emission factors for a closer comparison with emission factors from our study, which are on a tank-basis. Fortunately, in addition to tank throughput, the EPA also reported atmospheric storage tank counts to the GHGRP by tank class (in EPA [21], the tank-based approach is discussed as an alternative considered at the time). The steps in constructing a tank-basis estimate are like those outlined above. Steps 1-5 are identical, with the exception that tank counts are used for scaling of tank throughput. For extrapolation, we scale up activity data based on the ratio of subpart W reported well counts to actual well count in the United States. This extrapolation assumes that the number of tanks per well is consistent, on average, between reporting wells and non-reporting wells.

We present reconstructed emission factors in **Table S23** (tank flashing emissions) and **Table S24** (those due to malfunctioning dump valves). We also demonstrate how activity data is scaled up from subpart W (representative sample) to the national population. Note that, although we find reasonable agreement, our reconstructed values do not match perfectly with emission factors reported in the GHGI. It is possible that differences between our reconstructed emission factors and reported values in the GHGI could be due to differences in how throughput was allocated across storage tank classes. **Table S23** and **Table S24** also compare our extrapolated emissions totals with those presented in the GHGI. In most cases our extrapolations overestimate the GHGI, except for condensate tanks with a throughput-basis extrapolation. This overestimation is higher on a tank-basis versus a throughput-basis. We encounter these differences because tank

throughput does not necessarily correlate with tank count. Without more detailed reporting on throughput per class, we cannot reconstruct these total emissions estimates more accurately.

**Table S23: Comparing flash emissions activity, emission factors, and total emissions for liquids storage tanks in natural gas systems and petroleum systems for this study's GHGI reconstructed values and actual GHGI values (reporting year 2015). Reconstructed values are calculated using GHGRP data downloaded from the EPA Envirofacts website** [26] **processed using steps outlined in** [21]**. Totals do not match exactly with totals reporting in the EPA GHGI.**

| | Condensate | | | | | Oil | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Large | | | Small | | Large | | | Small | |
| | VRU | Vent | Flare | Vent | Flare | VRU | Vent | Flare | Vent | Flare |
| **Reconstruction - Throughput basis** | | | | | | | | | | |
| Throughput (MMbbl/year) | | | | | | | | | | |
| Total | | | 235.8 | | | | | 2158.1 | | |
| Fraction by tank type | 11% | 12% | 55% | 14% | 7% | 23% | 14% | 58% | 5% | 1% |
| Total by tank type | 26.3 | 29.1 | 130.2 | 33.2 | 17.0 | 492.7 | 299.5 | 1248.8 | 99.2 | 18.0 |
| Emissions factor (kg CH4/bbl/year) | 0.003 | 0.202 | 0.005 | 0.364 | 0.007 | 0.008 | 0.207 | 0.007 | 0.161 | 0.003 |
| Emissions (kilotonnes/year) | 0.088 | 5.884 | 0.654 | 12.082 | 0.115 | 4.159 | 62.014 | 9.214 | 15.936 | 0.056 |
| Total emissions (kilotonnes/year) | | | 18.8 | | | | | 91.4 | | |
| **Reconstruction - Tank basis** | | | | | | | | | | |
| Tank count | | | | | | | | | | |
| Reporting to subpart W | 2758 | 8506 | 15845 | 84637 | 15723 | 12223 | 37504 | 73383 | 35133 | 11014 |
| Extrapolated to total US population | 3884 | 11980 | 22317 | 119206 | 22145 | 31849 | 97722 | 191209 | 91544 | 28698 |
| Emissions factor (kg CH4/tank/year) | 31.0 | 669.2 | 39.9 | 138.1 | 7.1 | 205.9 | 1000.5 | 76.0 | 274.0 | 3.1 |
| Emissions (kilotonnes/year) | 0.120 | 8.018 | 0.891 | 16.464 | 0.157 | 6.556 | 97.771 | 14.527 | 25.086 | 0.089 |
| Total emissions (kilotonnes/year) | | | 25.6 | | | | | 144.0 | | |
| **Greenhouse Gas Inventory - Throughput basis** | | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Throughput (MMbbl/year) | 25.2 | 32.5 | 124.7 | 35.2 | 17.5 | 394.0 | 325.7 | 970.8 | 85.3 | 28.8 |
| Emissions factor (kg CH4/bbl/year) | 0.003 | 0.173 | 0.005 | 0.518 | 0.006 | 0.008 | 0.149 | 0.007 | 0.045 | 0.002 |
| Total emissions (kilotonnes/year) | 0.085 | 5.633 | 0.626 | 18.211 | 0.110 | 3.257 | 48.573 | 7.217 | 3.823 | 0.044 |
| Total emissions (kilotonnes/year) | 24.7 | | | | | 62.9 | | | | |

**Table S24: Comparing malfunctioning separator dump valve throughput-basis activity, emission factors, and total emissions for liquid storage tanks in natural gas systems and petroleum systems for this study's GHGI reconstructed values and actual GHGI values (reporting year 2015). Calculated using GHGRP data downloaded from the EPA Envirofacts website** [26] **processed using steps outlined in** [21]**. Totals do not match exactly with totals reporting in the EPA GHGI.**

| | Condensate | Oil |
|---|---|---|
| | Reconstruction - throughput-basis | |
| Throughput (MMbbl/year) | 236 | 2158 |
| Emissions factor (kg CH4/bbl/year) | 0.0003 | 0.0030 |
| Emissions (kilotonnes/year) | 0.073 | 6.502 |
| | Reconstruction - tank-basis | |
| Tank count | 179533 | 441021 |
| Failure rate | 0.06% | 1.56% |
| Emissions factor (kg CH4/tank/year) | 724 | 1308 |
| Emissions (kilotonnes) | 0.084 | 9.025 |
| | Greenhouse Gas Inventory | |
| Throughput (MMbbl/year) | 182 | 1690 |
| Emissions factor (kg CH4/bbl/year) | 0.0003 | 0.0028 |
| Emissions (kilotonnes/year) | 0.055 | 4.816 |

### *5.3.3. Reanalysis of emission factor distributions and comparison with this study*

Using our datasets constructed in the previous section, in addition to reconstructing average emission factors we can also construct emission factor distributions. To make an apples-to-apples comparison between this study's emission factor distributions and the GHGI emission factor distributions we will use emission factors with a tank-basis. For every sub-basin (or row in the GHGRP datasets), sub-basin emission factors are calculated by dividing sub-basin emissions by tank count.

This study's approach to calculating emission factors is described in Section 3.3.2. Briefly, our approach relies on quantified emissions measurements made at multiple sources on tanks, including vent stacks, pressure-relief valves, and thief hatches to estimate unintentional emissions. These measurements are combined with flash emissions measurements from the HARC study, which we use to estimate intentional emissions from uncontrolled storage tanks.

In the GHGI emissions from storage tanks are classified as those emitted from controlled tanks (equipped with VRUs or flares) or those emitted from uncontrolled tanks (not equipped with a control device). Emissions due to malfunctioning separator dump valves are only possible at uncontrolled tanks. In contrast, our approach to estimating tank emissions is source-based (see Section 3.3.2). Therefore, to make a comparison between emissions distributions we adopt the GHGI classification scheme and bin emissions sources according to **Table S25**.

**Table S25: Categorization of emissions sources in this study's model into GHGI categories. This categorization is required because emissions in our model database are directly attributed to specific tank components. Assumptions about how these emissions sources are reflected in controlled and uncontrolled tanks must be made post-hoc. In contrast, assumptions about specific emissions sources are inherent to the simulations made by emissions reporters.**

| | Dataset | |
|---|---|---|
| | This study | GHGI |
| Controlled | - Quantified measurements of emissions from hatches, holes, pressure-relief valves | - Simulated emissions from controlled tanks (based on operator reported efficiencies of VRUs and flares)<br>- Flaring emissions |
| Uncontrolled | - Quantified measurements of emissions from hatches, holes, pressure-relief valves<br>- Quantified measurements of flash emissions | - Simulated emissions from uncontrolled tanks<br>- Reported malfunctioning separator dump valve emissions |

We make several observations based on the graphical comparison of this study's emission factor distributions with the reconstructed distributions of the GHGI (**Figure S27**). Perhaps most notably, our study finds much greater emissions from controlled tanks (i.e., tanks with VRUs or flares attached). This study's emissions from controlled tanks are based on empirical datasets [13], [17], [56] which identify multiple points of failure on tanks beyond the vent stack, VRU, or flare. Key points of failure driving emissions include open thief hatches and rusted holes. If thief hatches are open or the tank exterior is compromised with a hole, VRUs and flares are irrelevant as the gas will escape from the open port naturally as it is the path of least resistance. It should be noted that the GHGI also includes a separate category for malfunctioning separator dump valves. As they are reported in the GHGI, emission factors from malfunctioning separator dump valves can be high (100s of $kgCH_4$/day), but because these are extremely infrequent, total emissions contributions are low. It must be noted that although we assume emissions from malfunctioning dump valves are from uncontrolled tanks, this is not explicitly stated anywhere in the GHGI.

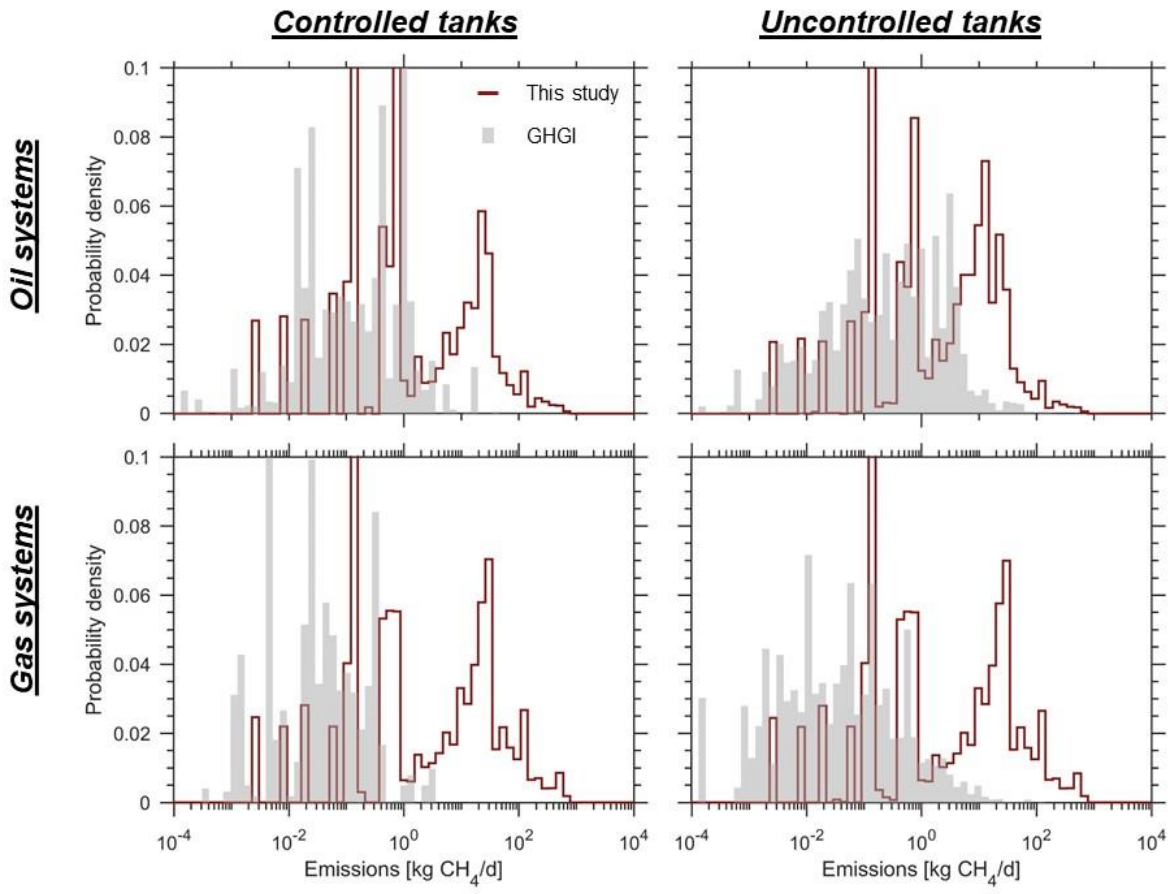


**Figure S27: Comparison of storage-tank related emissions probability distributions [kg CH4/tank/ day] between this study and the GHGI. Comparisons are made according to product-stream (natural gas versus petroleum, bottom-row versus top-row, respectively) and tank class (controlled versus uncontrolled, left-column versus right-column, respectively). For organization of emissions streams by tank class, see Table S25. Note that values for the GHGI are low because they are simulated volumes, not measured. We speculate that spikes in our data are probably based on measurement lower-limits for Hi Flow samplers.**

One outcome of the comparison in **Figure S27** between this study and the GHGI is that while there are clear differences in emissions distributions between controlled tanks and uncontrolled tanks and between gas sites and petroleum sites for the EPA, this is less the case for our model (i.e., the distributions for all categories look similar). This has to do with the fact that in our model emissions are dominated by unintentional emissions events from thief hatches, pressure-relief valves, and rust related holes. Because each of these sources precede capture or control devices like VRUs and flares, these emissions can occur at either controlled or uncontrolled tanks. We

elaborate on this result in the main text, with additional supporting evidence from aerial and ground surveys in **Table S26.**

**Table S26: Ground and aerial surveys conducted with a focus on liquid storage tanks. These studies did not contain quantified emissions measurements useful for our model dataset (while Clearstone** [13] **did, the measurements were taken in Canada and thus may not be representative of the U.S.) but provide evidence that unintentional emissions events at storage tanks are frequent and large in magnitude, both at controlled and uncontrolled tanks.**

| | |
|---|---|
| Clearstone 2018 [13] | Clearstone conducted a ground-based, component-level survey of 333 O&NG well-pads in Alberta, Canada. Clearstone found that emissions from production storage tanks accounted for 28% of the total survey emissions. Thief hatch emissions were documented at 6 of 52 (11%) of surveyed tanks. |
| Lyon et al. 2016 [57] | Lyon et al conduct helicopter-based IR camera surveys of 8220 O&NG well pads in seven basins. Lyon et al detected a total of 494 unique high emissions sources at 327 wells pads (4% of wellpads, ranging from 1% in the Powder River basin to 14% in the Bakken), with tank hatches and tank vents comprising 92% of observations.<br>Correlations were also assessed between emissions detection frequency and several defining well-pad characteristics. As Lyon et al. conclude: "this study found statistically significant correlations between the presence of detected emissions and several well pad and operator parameters, these relationships were weak and GLM models were able to explain less than 15% of the variance. This low degree of predictability indicates that these large emission sources are primarily stochastic". |
| Lyman et al. 2019 [58] | Lyman et al conducted a study with methods similar to Mansfied et al and Lyon et al. In this study, 3,225 well-pads are surveyed from the air, and 419 of the same well-pads are surveyed from the ground. Counterintuitively, well-pads with controlled tanks were more likely to have detected emissions compared to well-pads with uncontrolled tanks. According to Lyman et al., this was due to the fact that "most emissions were not from the control devices themselves, but from tank hatches, vents or piping upstream of control devices". |
| Mansfield et al. 2017 [59] | Mansfield et al conducted a ground-based survey of 454 O&NG well-pads with controlled tanks only. Even though the tanks were controlled, 196 plumes were observed at 178 wells (39% of well-pads). 79% of plumes were from thief hatches or pressure-relief valves. As Mansfield et al. suggest: "the problem is not so much a failure of control devices themselves, but a failure to adequately deliver escaping gases to the control device". |
| Englander et al. 2018 [60] | One year after the Lyon et al. survey, Englander et al. performed an infrared optical gas imaging survey in the Bakken formation using the same helicopter crew to examine persistence of large emitters. Englander et al. found that well pads emitting in 2014 were more likely (than random chance) to be emitting in 2015. Overall, emissions were detected at 11% of wellpads with tank vents or hatches accounting for 90% of observations. |

### *5.3.4. Emission factor decompositions*

In the main text we present and discuss a decomposition of emission factors for storage tanks. Here, emission factors are the summation of flash emission factors and unintentional emission factors (e.g., thief hatch emissions for this study and malfunctioning separator dump valves for the EPA). The decomposition for petroleum systems is shown as **Figure 5**. The decomposition for natural gas systems is shown as **Figure S28**.

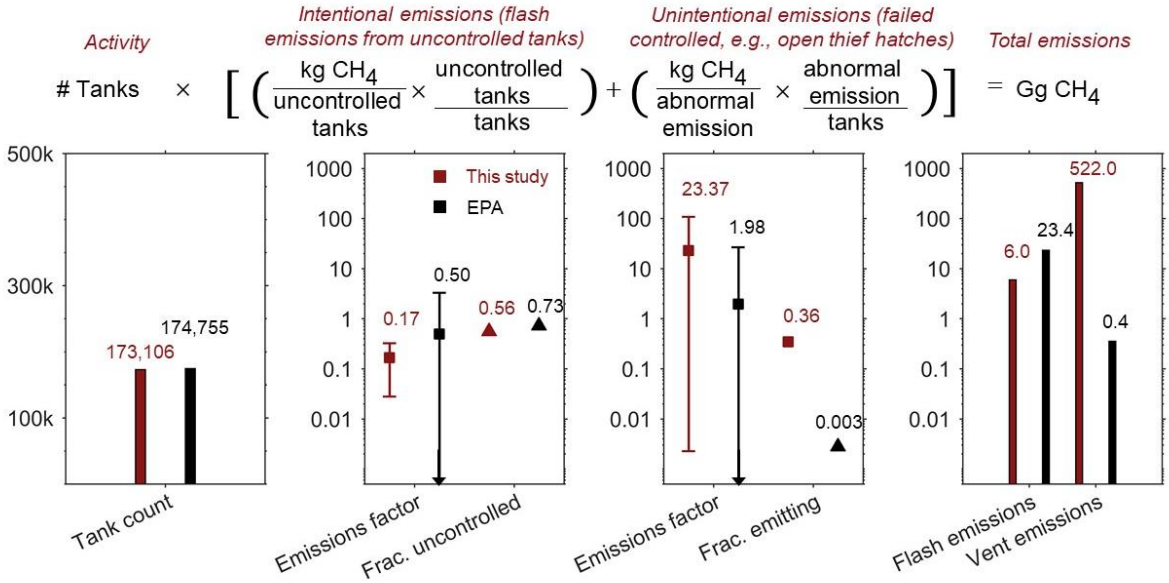


**Figure S28: Decomposition of total emissions for condensate tanks (far right panel) into constituent parts, with comparison of this study's dataset to those of the GHGI. From left to right: Total activity, flash emission factor panel, unintentional emission factor panel, and total emissions. Flash and unintentional emission factors are decomposed into emission factors (kg CH4/ emitting tanks) and control rates (emitting tanks/ total tanks).**

### *5.3.5. How does the GHGRP account for thief hatch emissions?*

If the GHGRP were accounting for thief hatch emissions, it would be under 40 CFR 98.233(q) "Equipment leak surveys" or 98.233(j) "Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks" [6]. However, components under the purview of "Equipment leak surveys" are listed in 98.232(c)(21) which explicitly states that it "does not include thief hatches or other openings on a storage vessel". 98.233(j) does not mention thief hatches or any other openings, although it is debatable if thief hatches could be contained within

"storage tank vented emissions from produced hydrocarbons" (as the section is defined 98.232(c)(21)).

This point is clarified in the EPA's 2016 "Leak detection methodology revisions" (81 FR 86490, [61]) where the EPA "amend[ed] subpart W to add new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the NPSP subpart OOOOa". This required clarifying the definition of fugitive emissions components. The EPA notes that thief hatches are defined as a "fugitive emissions component" for the purposes of NSPS subpart OOOOa [16] but not for the purposes of subpart W. The decision is made to maintain the exclusion of thief hatches from the list of "fugitive emissions components" in subpart W as "the subpart W calculation methodology for storage tanks in 40 CFR 98.233(j) already includes emissions from thief hatches or other openings on storage vessels". The EPA defends this decision by noting how "if a reporter sees fugitives emissions from a thief hatch or other opening on a controlled storage vessel during an equipment leak survey conducted using OGI, the reporter should consider that information as part of the 'best available data' used to calculate emissions from that storage tank".

Unfortunately, based on how information is reported to the GHGRP, it is impossible to determine how many reporters are taking thief hatches and storage vessel openings into account.

## 6. Summary of surveyed studies

Key details of each study can be found in **Table S28**. Additional details are provided in the following sections.

**Table S27: Summaries of studies used for emissions measurements, fraction components emitting, or component counts**

| | |
|---|---|
| Allen et al 2013 [15] | |
| Location | Gulf Coast, Midcontinent, Rocky Mountain, and Appalachian production regions. All wells sampled were hydraulically fractured |
| Types of equipment | Production phase and drilling/completions operations |
| Emissions quantification data: | Various components sampled. According to Allen et al., "The focus in this work was on measuring emissions from pneumatic pumps and controllers and measuring leaks from equipment, pipes, flanges and fittings" |
| Component counts | Counts of components surveyed was not reported |
| Fraction emitting | Fraction of components leaking was not reported (given that total components weren't counted). |
| Allen et al 2014a [8] | |
| Location | Sampling was conducted across four regions (Appalachian, Gulf Coast, Mid-continent, Rocky Mountain) and a stated goal was to "sample a cross section of typical facilities" across different service types. |
| Types of equipment | Pneumatic controllers |
| Emissions quantification data | Allen et al quantified emissions from 377 pneumatic controllers (PC). Each PC is classified as using its actuation pattern as "intermittent" or "continuous", as well as by its emissions rate as "low-bleed", "high-bleed", "intermittent", or "not classified" |
| Component counts | Allen 2014a gives the number of pneumatic devices measured per site visited, total number of pneumatic devices per site, count of wells per site, and pneumatic devices per well. See Allen 2014a, SI table S6-1. |
| Fraction emitting | According to the manuscript, 75% of wells have pneumatic controllers with documented emissions (the other 25% have non-pneumatic controllers/actuators) |
| Bell et al 2017 [18] | |
| Location | Fayetteville AR |
| Types of equipment | All upstream equipment |
| Emissions quantification data | Bell et al. 2017 conducted on-site measurements using a High-flow sampler at 261 facilities |
| Component counts | Counts of components surveyed was not reported |
| Fraction emitting | Fraction of components leaking was not reported (given that total components weren't counted). |
| ERG 2011 [17] | |
| Location | Fort Worth, TX (Located in the Barnett shale) |
| Types of equipment | Production sites, compressor stations, etc. |
| Emissions quantification data | ERG 2011 supplemental information contains ~2000 quantified leaks with leak type, site type, and other information. Leaks are broken down into 95 component categories, many more than other studies. ERG does not give equipment categories. Each measurement contains supplemental text or notes, but these are not standardized and therefore difficult to parse for information. |
| Component counts | Supplemental information provides a mix of equipment-level and component-level counts. The dataset does not give information about which valves and connectors are associated with each piece of equipment. This makes the dataset not useful for estimating, for example, the number of connectors or valves per compressor |

| | |
|---|---|
| Fraction emitting | Because component counts are available for connectors, valves, and tanks, we can estimate fraction of components emitting. However, ERG note that only one in ten components were screened using Method 21. Therefore, in calculating fraction of components emitting, the emitter count < 10,000 ppmv was multiplied by ten. |
| Thoma et al 2017 [62] | |
| Location | Uintah Basin, UT |
| Types of equipment | Pneumatic controllers |
| Emissions quantification data | Thoma et al. surveyed 80 pneumatic controllers (PC). All PCs in the Thoma study are assigned a minimum continuous emissions rate of 0.1 scf/h |
| Component counts | n/a |
| Fraction emitting | n/a |
| Pasci et al 2019 [14] | |
| Location | Permian, Anadarko, Gulf Coast, and San Juan basins |
| Types of Equipment | Production and gathering and boosting segments |
| Emissions quantification data | Supplementary information contains 331 speciated leaks, of which 261 are at well sites |
| Component counts | At each site an equipment count and component count was determined. Components were classified into one of 12 categories |
| Fraction emitting | Both emitter count and component counts are reported so total fraction of components emitting can be determined by component |
| API 4589 [3] | |
| Location | Various US |
| Types of equipment | Sites 1-4 were light crude oil fields. Sites 5-8 were heavy crude oil fields. Sites 9-12 were gas production fields. Sites 13-16 were gas plants. Sites 17-20 were offshore fields. A later study (API 1995 or API#4615, [40]) added four more gas plants as sites 21-24 . |
| Emissions quantification data | Appendix C contains concentration measurements (ppmv) for all screened components. These concentrations can be converted to emissions fluxes using correlation equations and "pegged source factors".<br>Technology applied: Method 21 flame ionization detector |
| Component counts | Appendix B of API 1993 contains activity data on component counts for pieces of equipment contained across all 20 sites, with a total of 1446 pieces of equipment included. Component counts are given for the following component types: Connectors, valves, open-ended lines, compressor seals, pump seals, pressure-relief valves, and other. The miscellaneous "other" category includes dump-lever-arms, polished-rod pumps, and miscellaneous. |
| Fraction emitting | API 1993 contains data on the fraction of components classified as emitters via the ISV threshold of >10 ppmv. For the 20 sites, the fraction of components classified as emitters is given in in Table 1-1 of API 1993. In the appendices, the-per leak ISV readings are presented which would allow one to adjust for a different fraction of components emitting. |
| Clearstone 2018 [13] | |
| Location | Alberta, Canada |
| Types of equipment | Upstream oil and natural gas sites and compressor stations |
| Emissions quantification data | Appendix Raw data provided by Lindsay Campbell of the Alberta Energy Regulator to Jeff Rutherford on November 4, 2019<br>Technology applied: Hi Flow Sampler for leak quantification |
| Component counts | Field work included a detailed equipment and component count inventory (12 standardized component types). |

| | |
|---|---|
| Fraction leaking | Both leakage count and component counts are reported so total fraction leaking can be determined by component |

*Allen 2013: "Measurements of methane emissions at natural gas production sites in the United States"*

Allen et al. [15] present results from one of the earliest studies in the recent era of methane quantification research and the first results from the large multi-study EDF campaign. Allen et al. quantified emissions from 190 onshore gas sites, including 150 production sites, 27 well completions flowbacks, 9 liquids unloading, and 4 well workovers. Gas sites were located in the Gulf Coast, Mid-continent, Rocky Mountain, and Appalachian regions of the United States. It is noted in the study that measurements were made exclusively at shale gas, hydraulically fractured well sites. Quantified volumes are presented for a variety of emitters.

The approach taken by this study was to first scan a site using an infrared camera to identify possible emitters. All identified emitters were measured with a high-flow sampler. Component counts per equipment were not inventoried. Rather, emitters are reported “per well” and emissions are scaled according to well count.

The Allen et al. dataset contains 124 measurements of tank vents. However, according to correspondence with David Allen (August 17, 2018) these measurements were for exploratory purposes only and should not be used in analysis.

*Allen 2014a: “Methane emissions from process equipment at natural gas production sites in the United States: Pneumatic controllers”*

Allen et al. [8] examined pneumatic controllers at well sites, focusing on natural gas production sites. Sampling was conducted across the Gulf coast, Mid-continent, Rocky Mountain, and Appalachian regions of the United States. A stated goal of the study was to “sample a cross-section of typical facilities” across different service types. Measurements were made from 377 pneumatic controllers.

The majority of measurements (333 of 377) were made using a Fox flow meter. The remainder of measurements were made using a high-flow sampler. Because pneumatic controllers activate discontinuously, average emissions were taken over 15 minute periods for both the flow meter

and High flow sampler approaches. Allen et al. note that it's possible that some emissions may have been missed if devices did not activate during the 15 minute period.

Supplemental information files from the study include number of pneumatic controllers per well, as shown in Table S6-1 in file "es5040156_si_002.xlsx". Table S4-1 gives many properties of each measured pneumatic controller, including the basic application and detailed application. Unfortunately, though some pneumatic controllers were found on dehydration systems or separators, the study does not report equipment counts for those types of equipment per site, only well counts per site.

*Bell et al. 2017: "Comparison of methane emission estimates from multiple measurement techniques at natural gas production pads"*

Bell et al. [18] present results from field studies in the Fayetteville shale gas play. No additional details are provided on the service type (e.g., gas versus oil) or completions type (e.g., hydraulically fractured) of these wells. Several measurement techniques were compared, including onsite measurements, the dual tracer flux ratio method, and the EPA Other Test Method 33a. 268 gas production facilities were sampled, and on-site measurements were made at 261 facilities.

Onsite direct measurement involved detection using "a combination of optical gas imaging and handheld laser methane detection" and quantification using a high-flow sampler. Only onsite direct measurements were used for this study.

Several "zero" values are contained in the Bell et al. dataset. This includes data points classified as "Below High Flow Range" (some but not all equal to zero) and "Observed not measured". Most measurements labelled "Below High Flow Range" and all "Observed not measured" were filtered out of our final dataset.

*Eastern Research Group (2011): "City of Fort Worth Natural Gas Air Quality Study"*

This project was conducted by Eastern Research Group (ERG) for the Fort Worth Natural Gas Air Quality Study (FWAQS) in 2010 and 2011. Fort Worth is located within the Barnett shale, the formation where hydraulic fracturing was first implemented.

The FWAQS team deployed two teams to detect leaks:

- A team with an infrared camera (FLIR) surveyed all components at the site and all observed leaks were reported
- A second team used Method 21 testing (using a toxic vapor analyzer) to survey 1 out of every 10 connectors and valves
- While the IR camera survey was taking place, the second crew member would conduct an equipment/component count which included number of storage tanks and counts of connectors and valves. The report notes that only valves were counted, and a multiplier of 7 was used to estimate connector counts

A Bacharach Hi Flow sampler was used to measure emission points identified with the FLIR camera or Method 21 screening > 500 ppmv.

ERG [17] document extensive detail on 388 sites visited. These data are recorded on sheet "Executive PS Site Summary" in worksheet "EmissionsCalculations.xlsx". The sites are classified by type of gas and listed with operator and location. Equipment counts for each site include number of wells, tanks, and compressors per site.

The largest sources of emissions detected by ERG were tank related. These tank related emissions fall into one of three categories: (i) Thief hatch, (ii) tank vent, (iii) and tank PRV vent. Evidence suggests that separator failure (e.g., free gas released into tanks) can lead to over-pressurization and release via the thief hatch or PRV. Thus, we classify emissions labelled as thief hatch, PRV, or vent in the ERG dataset as losses due to "tanks-vents" (section 3.3.2). The ability of the ERG study to capture tank related superemitters is particularly important, as previous works have questioned the ability of on-site techniques (e.g., Hi Flow sampling) to measure these emissions based on safety concerns and access allowances from site operators [63]. While this may have been true for other direct measurement campaigns (e.g., [15]) both pictures provided in the ERG report and the magnitudes of tank measurements (> $10^2$ kg/day) suggest that both unusual site access privileges and sampling approaches were made.

ERG note that some low-level emitters (500 – 10,000 ppmv) were below the detection capability of the High flow sampler. For Phase II measurements, some of these low-level emissions were estimated through the use of correlation equations.

*Thoma 2017: "Uinta Basin Well Pad Pneumatic Controller Emissions Research Study"*

Thoma et al. [62] analyzed a total 80 pneumatic controllers at five oil sites (containing 6 wells) and three gas sites (containing 12 wells) in the Uinta Basin. Emissions were quantified from the pneumatic controllers and counts of pneumatic controllers per well were computed.

Screening was conducted with both an infrared camera (FLIR) and Method 21 testing using a handheld probe. Emissions quantification was conducted using a combination of flow meter measurements and high flow sampler measurements.

*Pacsi et al. 2019: "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States"*

Pacsi et al. [14] analyzed 67 oil and natural production and gathering and boosting sites in the Permian, Anadarko, Gulf Coast, and San Juan basins. Measurements were taken at both oil and natural gas producing sites (no GOR threshold is provided). Nearly 84,000 components were monitored.

Leak screening was conducted with a combination of Method 21 (flame ionization detectors) and optical gas imaging cameras. For each leak identified, emissions rates were measured with a high flow sampler.

*American Petroleum Institute (1993): "Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations"*

The API report "Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations", or API-4589, gives results from the extensive API/GRI studies of 1993 [3]. API 1993 was also used in EPA documents, including serving as the source material for the EPA 1995 emission factor update [5] and the EPA 1996 15-volume analysis of methane emissions from oil and gas industries [41]. API 1993 contains information from 20 sites sampled for fugitive emissions from components.

In API 1993, EPA Method 21 was followed. A total of 184,035 components were screened across 20 sites (**Table S28**). During screening, instrument screening values (ISVs) greater than 10 ppmv were considered "emitters". A total of 4796 components (2.6% of total) were considered

emitters with ISV > 10 ppmv. A total of 705 of these emitters were sampled to quantify leakage rates and speciate the gases being leaked.

For our purposes, site 1-12 are useful (sites 13-16 were gas plants, and sites 17-20 were offshore fields). Sites 1-4 were light crude fields, sites 5-8 were heavy crude fields, and sites 9-12 were gas production fields.

Appendix C of the Western dataset reports all screening concentrations measured (in ppmv) with the associated component for each measurement. Information on total components screened is contained in Appendix D. All data in these appendices were digitized from scanned PDF form and manually double checked for accuracy. The Western dataset classifies equipment in the following categories: connectors, open-ended lines (OELs), valves, pressure-relief valves (PRVs), compressor seals, and other.

It should be noted that a continuation study was published in 1995 by API [9] (API 4615) which adds to the original 20 sites an additional 4 gas plants.

**Table S28: Components screened and found leaking in the API 4598 dataset** [3]

| Site type | Site # | Components screened | Components ISV > 10 ppmv | Components ISV > 10,000 ppmv | Samples collected | Fraction emitting @ 10,000 ppmv |
|---|---|---|---|---|---|---|
| Light crude | 1 | 27155 | 522 | 247 | 43 | 0.91% |
| Light crude | 2 | 14620 | 290 | 106 | 39 | 0.73% |
| Light crude | 3 | 4095 | 84 | 27 | 58 | 0.66% |
| Light crude | 4 | 2782 | 95 | 35 | 28 | 1.26% |
| Heavy crude | 5 | 6362 | 19 | 0 | 9 | 0.00% |
| Heavy crude | 6 | 2799 | 21 | 2 | 9 | 0.07% |
| Heavy crude | 7 | 2696 | 8 | 0 | 6 | 0.00% |
| Heavy crude | 8 | 1899 | 14 | 0 | 8 | 0.00% |
| Gas | 9 | 14066 | 324 | 126 | 23 | 0.90% |
| Gas | 10 | 9374 | 316 | 116 | 36 | 1.24% |
| Gas | 11 | 9094 | 628 | 318 | 22 | 3.50% |
| Gas | 12 | 7644 | 245 | 88 | 36 | 1.15% |

*Clearstone (2018): "Update of Equipment, Component, and Fugitive Emission Factors for Alberta Upstream Oil and Gas"*

Clearstone [13] documents screening performed in Alberta, Canada in August and September 2017 at 333 locations in order to improve Alberta's methane emissions factors and associated confidence intervals. In addition to emissions quantification, component counts and fraction of components emitting are also documented. This study targeted fugitive emissions specifically and includes a comprehensive and useful glossary of component and equipment definitions.

*Texas Environmental Research Consortium 2009 ("HARC" report):*

The "HARC study" is a direct measurement campaign (May 2006) of vent gas emissions from 33 tanks, covering both crude and condensate service across a range of API gravities, in the Dallas-Forth-Worth, Houston-Galveston-Brazoria, and Beaumont-Port Arthur counties. Calculated emission factors are intended to reflect "tank working, breathing, and flashing losses" [23], and represent *uncontrolled emissions* (e.g., tanks without vapor recovery units or flares). Prior to measurement, tanks were inspected for the presence of holes (due to rust) or open thief hatches. If tanks had holes no measurements were made, and all thief hatches were closed.

Tank emissions were measured by sampling the flow rate of vent gas through pipes located at the top of the tanks using a Fox Instruments Thermal Mass Flow Meter. Flow rates were measured over approximately 24 hours.

Measurements range from 0.002 – 5.945 kg $CH_4$/bbl and average 0.702 kg CH4/bbl (three tanks removed, 17, 25, and 26, due to unphysical mole fractions or abnormally high emissions rates).

*Gas Research Institute 1996*

In 1996, the Gas Research Institute (GRI) released a 15-volume compendium estimating US natural gas industry GHG emissions (see also the published summary by Kirchgessner et al [64] and methodology documented in the EPA Protocol document [5]). For the purposes of fugitive and vent methane emissions, the most useful document is "Volume 8: Equipment Leaks". As of the 2020 GHGI, emission factors for most equipment leaks in the NG systems are based off GRI volume 8 [41] (henceforth referred to as the "GRI report").

*Star Environmental 1995*

The 1995 Star Environmental report "Fugitive Hydrocarbon Emissions: Eastern Gas Wells" provided screening data for the Eastern US [4]. Star Environmental generated three sets of

emission factors using different permutations of two campaign datasets and applying either pegged source factors (see **Table S20**) or the Hi Flow Sampler. It is not clear which set of emissions factors were applied for the GRI report, however we presume the approach chosen was the "Hi Flow approach" emission factors (which use campaign 2 data and the Hi Flow sampler).

For campaign 2, a total of 12,853 components were screened across 8 different gas sites (**Table S29**) and a subset of the leaking components were quantified. All instrument readings > 100,000 ppmv (21 readings) and half of instrument readings > 10,000 ppmv (81 readings) were quantified with a Hi-Flow sampler and documented in the report Appendix.

Emission factors in Star Environmental were developed in a similar fashion to API 4598 [3] (Default-zero values were applied to screening values < 10 ppmv and EPA protocol correlation equations were applied to screening values >= 10 and < 9,999 ppmv). However, it is important to emphasize a key difference between the approaches of the Western gas and petroleum systems and the approach of Eastern gas systems. Recall that emission factors derived for Western gas systems and petroleum systems applied pegged source factors for screening measurements > 10,000 ppmv. For Eastern gas systems quantified Hi-Flow Sampler data was applied to screening data > 10,000 ppmv.

**Table S29: Components screened and found leaking in the Eastern dataset**

| Site number | Well sites | Components screened | Components ISV > 10 ppmv | Components ISV > 10,000 ppmv | Fraction emitting @ 10,000 ppmv |
|---|---|---|---|---|---|
| 4 | 15 | 1,385 | 52 | 16 | 1.16% |
| 5 | 13 | 1,134 | 60 | 17 | 1.50% |
| 6 | 20 | 2,065 | 65 | 19 | 0.92% |
| 7 | 11 | 1,257 | 58 | 22 | 1.75% |
| 8 | 14 | 1,368 | 89 | 38 | 2.78% |
| 9 | 8 | 1,017 | 45 | 13 | 1.28% |
| 10 | 15 | 2,417 | 76 | 22 | 0.91% |
| 11 | 8 | 962 | 50 | 21 | 2.18% |
| 12 | 13 | 1,248 | 42 | 15 | 1.20% |

**Table S30: Eastern dataset component-level emission factors**

| Component | Count | Fraction emitting @ 10,000 ppmv | Sampled with HFS | HFS leak rate [kg/day] |
|---|---|---|---|---|
| Connector | 10,325 | 1.12% | 65 | 0.07 |
| Valve | 2,310 | 2.16% | 24 | 0.54 |
| Open Ended Line | 84 | 15.48% | 10 | 0.12 |
| Other | 134 | 2.99% | 3 | 0.76 |

# 7. Supplementary Figures

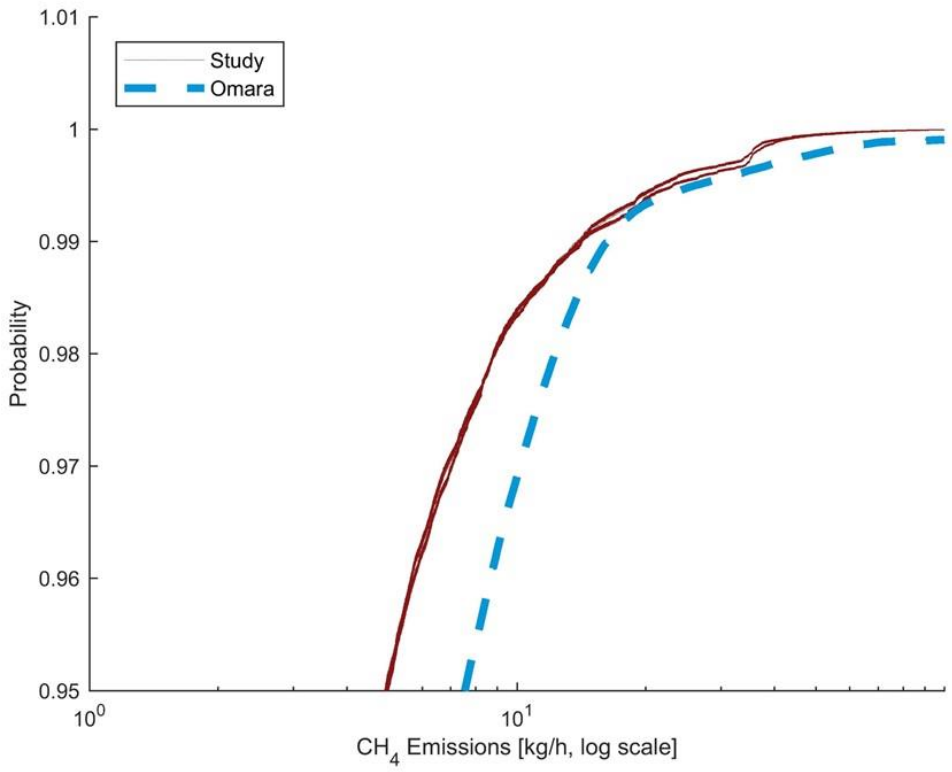


**Figure S28: Cumulative distribution plot of $CH_4$ emissions per well-site zoomed-in near the superemitter range. 100 Monte Carlo simulations of this study (red lines) are compared against results from Omara et al.** [39] **(blue line).**

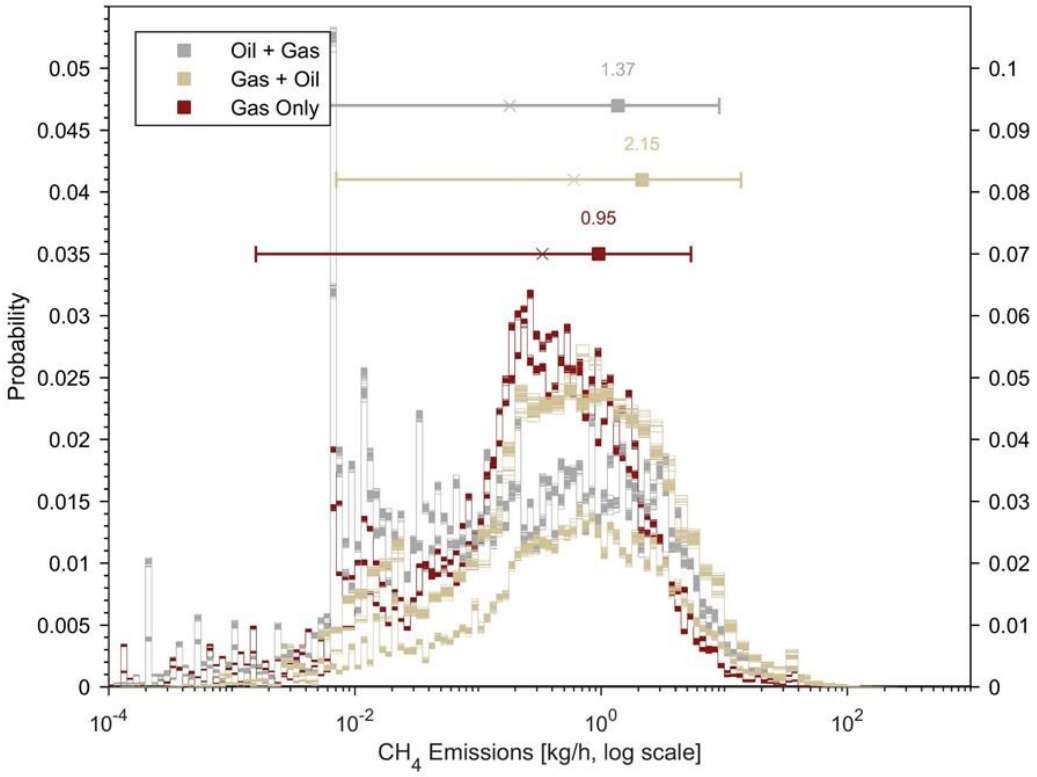


**Figure S29: Probability distribution of emissions rate per well-site for subsets of results distinguished by production stream. Note that "oil + gas" refers to sites with a GOR < 100 mscf/bbl producing associated gas, and "gas + oil" refers to sites with a GOR > 100 mscf/bbl producing associated liquids**

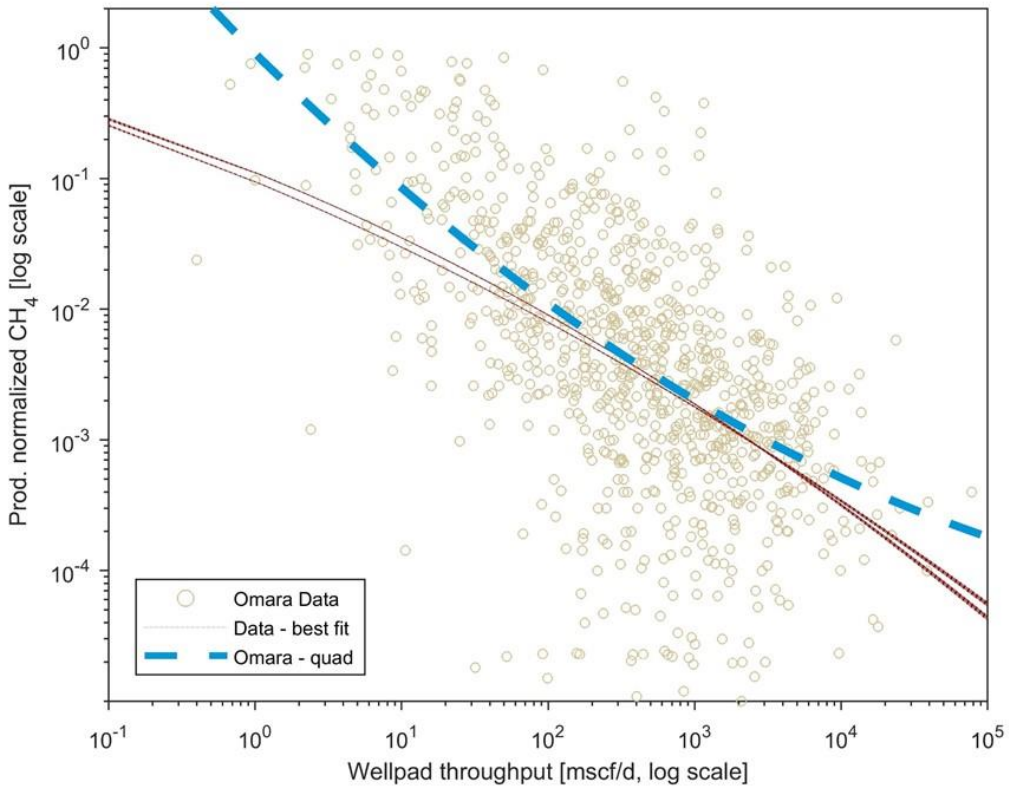


**Figure S30: Relationship between site-level productivity and production normalized emissions (e.g., fractional loss rate) for this study and Omara et al.** [39]**, respectively (model fits calculated using a quadratic weighted least squares regression).**

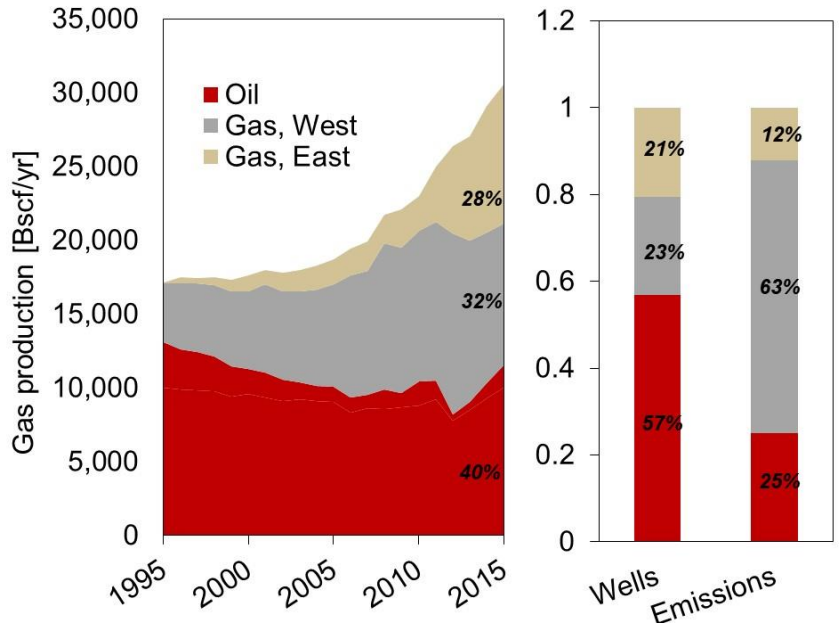


**Figure S31: Comparison of gas production, wells, and estimated share of US production sector CH4 emissions across oil producing wells, and NG producing wells in the Western and Eastern US. This differentiation matches the different data sources used in the GHGI..**

# 8. Supplementary Tables

**Table S31: Well counts for NG and petroleum systems**

| | | Wells | Total prod. (MMbbl/year) | Total prod. (Bscf/year) |
|---|---|---|---|---|
| NG | Gas only | 320,174 | 0 | 12,285 |
| | Assoc. oil | 113,256 | 22 | 6,650 |
| | Total | 433,430 | 22 | 18,935 |
| Petroleum | Oil only | 191,576 | 202 | 102 |
| | Assoc. gas | 380,185 | 2,561 | 12,692 |
| | Total | 571,761 | 2,763 | 12,794 |
| Total | | 1,005,191 | 2,785 | 31,729 |

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