Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings

Supporting Information

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S1. Methods for Site Selection

Goals and Overall Sampling Strategy. Sampling of emissions from gas well liquids unloadings was conducted in four major regions (Appalachian, Gulf Coast, Mid-continent, Rocky Mountain). The regions are shown in Figure S1-1.

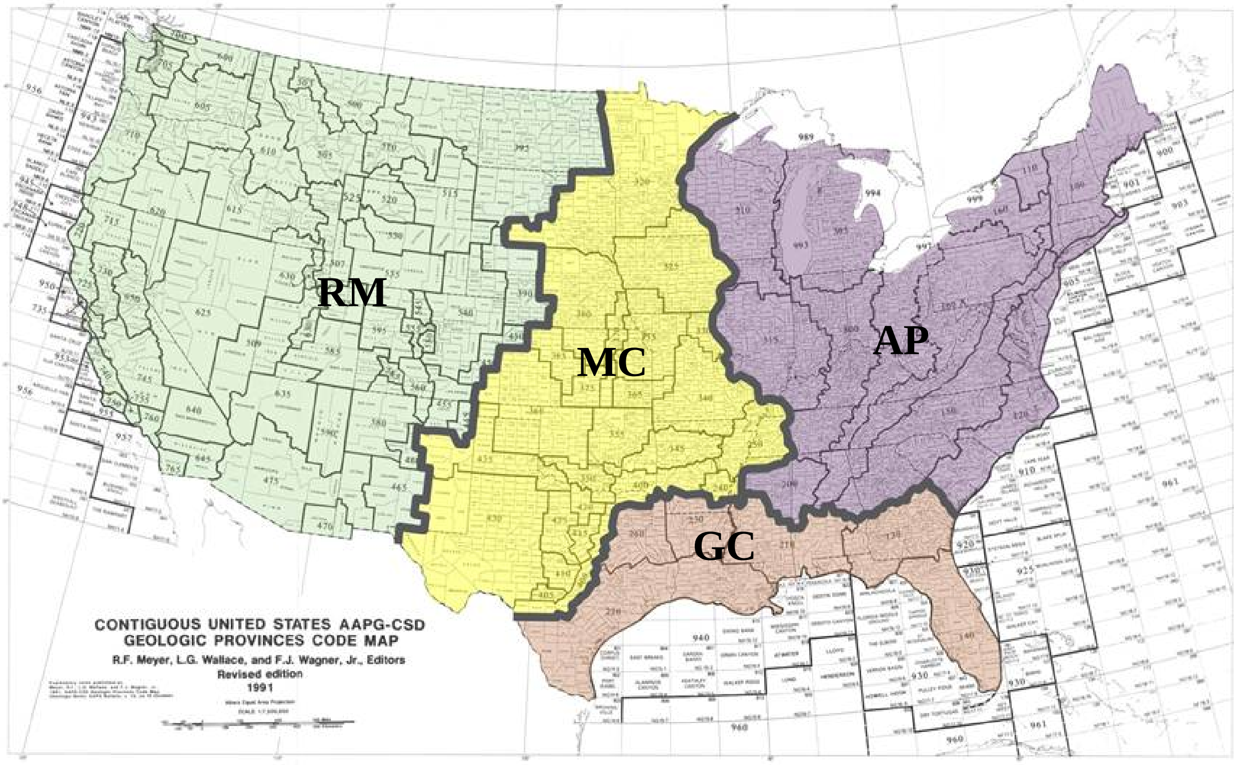


Figure S1-1: Basins of the American Association of Petroleum Geologists (AAPG) divided into 4 Major Regions for this study: AP=Appalachian; GC=Gulf Coast; MC=Mid-Continent; RM=Rocky Mountain.

It was anticipated that in each of the four regions, gas wells with and without plunger lifts would be sampled, and that within each of these categories, there would be a range of unloading frequencies, durations and liquid production rates. To adequately sample regions, well types (plunger and without plunger) and unloading event characteristics, it was anticipated that measurements of unloading emissions from approximately 100 different wells would be required.

Selection of Site Visit Duration and Scope. With a goal of 100 well unloading measurements, the project team conducted approximately 20 one-week visits to natural gas production regions with unloading emissions. It was anticipated that 5 wells could be sampled in a typical week. Production basins with the highest emissions, as reported through the U.S. EPA's Greenhouse Gas Reporting Program, were targeted. Each week of sampling was conducted with a single company in a single basin location.

Selection of Basins. Basins in which sampling was conducted were selected based on emissions reported through the EPA's Greenhouse Gas Reporting Program (GHGRP, Reporting Year 2012) Figure S1-2 shows Basins reporting unloading emissions through the GHGRP. Any basin colored blue had reported unloading emissions; uncolored (white) basins had no reported emissions. The darkest blue indicates basin total emissions for all reporters in excess of one million metric ton of CO_2e annually (based on a Global Warming Potential for methane of 21), medium blue indicates basin total emissions between 100,000 and 1,000,000 metric tons (MT) CO_2e annually, and lightest blue are basins that reported less than 100,000 MT CO_2e annually. There were 27 basins that reported unloading emissions in 2012.

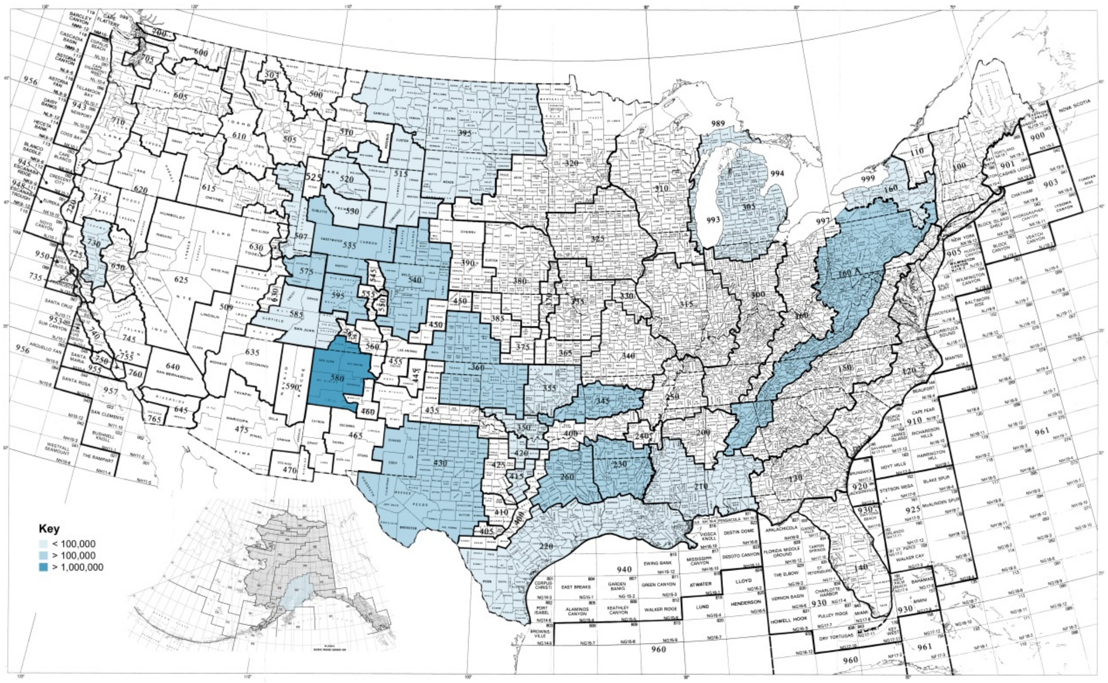


Figure S1-2: Basins of the American Association of Petroleum Geologists (AAPG) where unloadings were reported in 2012 to the EPA GHGRP.

Ten companies participating in this work reported 60% of the total unloading emissions for GHGRP reporting year 2012, and account for 28% of the wells that reported emissions.

Table S1-1 Spatial distribution of total unloading emissions reported in the GHGRP compared to the spatial distribution of emissions reported by companies that provided sampling sites

Region	AAPG Basin	Total GHGRP Emissions for 2012 (MT CO_2e)	% of total Basin emissions accounted for by companies providing sampling sites	% of total Basin wells that have unloadings accounted for by companies providing sampling sites
Appalachian	160A - Appalachian Eastern Overthrust	413,623	15.4%	14.5%
GC	220 - Gulf Coast Basin	74,525	31.0%	33.4%
	230 - Arkla Basin	148,126	8.4%	36.9%
	260 - East Texas Basin	242,828	82.4%	65.5%
MC	345 - Arkoma Basin	477,471	56.2%	69.6%
	350 - South Oklahoma Folded Belt	972	6.2%	6.9%
	360 - Anadarko Basin	310,355	1.2%	13.2%
	415 - Strawn Basin	43,050	48.3%	54.9%
	420 - Fort Worth Syncline	32,933	14.4%	39.1%
	430 - Permian Basin	179,707	1.8%	3.5%
RM	507 - Central Western Overthrust	42,505	14.0%	32.4%
	530 - Wind River Basin	4,743	84.5%	23.4%
	535 - Green River Basin	182,427	24.0%	40.2%
	540 - Denver Basin	102,335	6.1%	22.3%
	575 - Uintah Basin	149,584	8.9%	25.6%
	580 - San Juan Basin	2,315,772	96.4%	87.3%
	595 - Piceance Basin	943,554	79.2%	12.1%
Total US		**5,846,634**	**62.5%**	**27.6%**

Selection of Company and Basin Locations The Study Team, consisting of URS and University of Texas personnel, was solely responsible for the selection of regions and Basins in which to sample. For most basins, more than one of the ten participant companies has reported unloading emissions. If every participant company were visited in each basin where any participant unloading emissions were reported, there would have been 52 weeks of site visits. Since project scope and budget called for approximately 20 sample weeks, a subset of all possible participant sites were selected for sampling.

The selection of company sites required a balance among a number of goals. One goal was to sample at least 3 companies in each major region (AP, GC, MC, RM) shown in Figure S1-1. A second goal was to sample the basins with the largest reported emissions in the GHGRP. A third goal was to be able to sample each of the participant companies at least once. All companies that reported wells with unloading emissions were sampled in this program.

Once a basin was targeted for sampling, selection of the particular company to visit started with the participant company with the largest reported emissions in the basin, unless that company had already been sampled elsewhere, or unless one of the other participant companies only reported emissions in that single basin. Figure S1-3 shows the basins that were sampled during this measurement effort in late 2013 and early 2014. All basins with emissions of more than 100,000 MT CO_2e/yr from unloadings, as reported through the GHGRP, were sampled, with the exception of basin 360. The company targeted for basin 360 did not have had any unloading events for the week selected for a site visit to Basin 360.

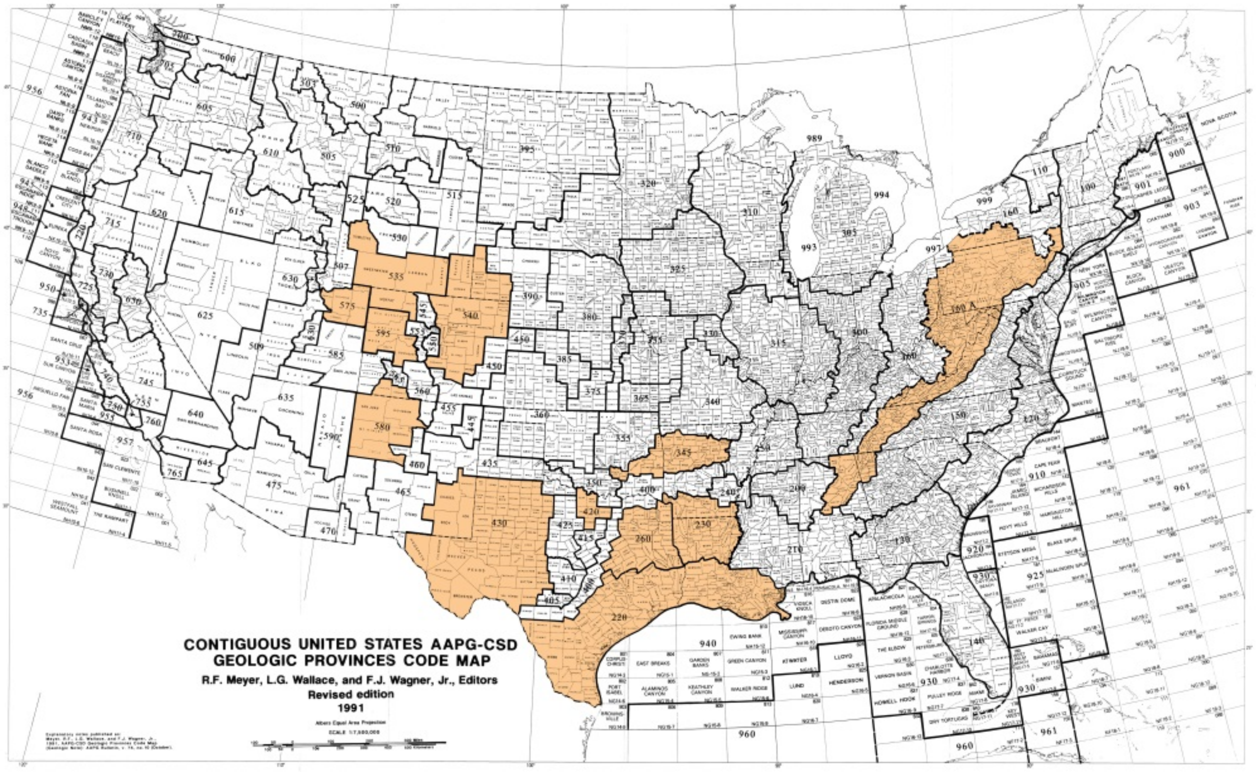


Figure S1-3. Basins of the American Association of Petroleum Geologists (AAPG) where unloadings measurements were made in this work.

Once a Basin and company to be sampled was selected, local contacts for participant companies provided descriptions of the types of unloadings and typical frequencies expected. No companies refused a site visit. Once at a site, the Study Team measured emissions from as many wells as could be visited and measured in the week. In some cases this involved sampling every unloading that occurred during the week for the company being visited. When more unloadings were available than could be sampled during a week, the Study Team selected which wells to visit.

S.2 Corrections to Instrument Flow Measurements based on Temporary Stack Size and Gas Composition

When safe and technically possible, the flow measurements of gas volumes released during liquid unloadings were taken using a temporary stack affixed to a tank vent that was equipped with a gas velocity measurement instrument (Fox Thermal Instruments, Model #FT3). On sites where the unloading flow was directed to an open top blowdown tank, rather than a fixed roof tank, a length of pipe was inserted into the piping to the open top tank that was used for the unloading, allowing for measurement of the flow into the tank. The Fox #FT3 device measured velocity over a 1.4" measurement length (with 0.5 inch thickness), which was centered in the temporary stack or pipe. The average-center line velocity measured by the Fox #FT3 was converted to an average velocity in the temporary stack or pipe by assuming that the velocity distribution was well-represented by a one-seventh power law velocity distribution.

$$\frac{v(r)}{v_{max}} = \left(1 - \frac{r}{R}\right)^{1/7} \qquad \text{(Equation S2-1)}$$

where *v(r)* is the velocity at distance r from the tube centerline, and R is the radius of the temporary stack or pipe. Typically, the power law order (in this case 1/7) is a function of the Reynolds number of the flow. However, over a wide range of Reynolds numbers, the differences in the predicted stack velocities are not sensitive to the assumed order of the power law function (between 1/7 and 1/9) except near the stack or pipe wall. In this work, the measurements were made near the center-line, and the effect near the stack or pipe wall would be expected to be minimal.

The specific relationship between the measured velocity and the overall average velocity depended on the size of the stack or pipe, since the 1.4 inch Fox #FT3 probe measured a different proportion of the cross sectional flow for different sized pipes. For all stacks and pipes, the ratio of the center-line (maximum) velocity to the average velocity over the entire pipe was 0.82. So, if the probe had only measured centerline velocity, the ratio of the average velocity to measured centerline velocity would be 0.82. The actual ratio of the measured velocity to the maximum velocity was dependent on the fraction of the diameter of the pipe that was sampled by the 1.4 in. probe. The correction factor was calculated using the one seventh-order power law distribution, and an assumption that the probe was exactly centered. The parameters for the pipes and stacks used in this study are summarized in Table S2-1.

Table S2-1. Correction factors used to account for the difference in the measured velocity and the average velocity through the pipe or stack. Note that the 2.5” nominal diameter stack was only used for the calibration of some of the Fox #FT3 devices and was not used for in-field measurements during the study.

Nominal Stack Diameter (in)	Stack Internal Diameter (in)	Proportion of Stack Diameter Measured (r/R)	Ratio of Measured Velocity to Center-Line Velocity (Average velocity =0.82 * centerline velocity)
2	2.060	0.68	0.93
2.5	2.469	0.57	0.95
3	3.068	0.46	0.96
6	5.76	0.24	0.98
8	7.90	0.18	0.98

The volumetric flow rate is the average velocity in the stack or pipe multiplied by the cross-sectional area available for flow. In the measurements made in this study, the cross-sectional area available for flow is the cross-sectional area of the stack or pipe minus the area obstructed by the flow probe, as shown in Figure S2-1. The area available for flow through each of the stack sizes used in this study is shown in Table S2-2.

Figure S2-1. Fox #FT3 velocity probe centered in a 2” nominal diameter stack.

Table S2-2. Parameters for stacks and pipes used in this study and the unobstructed cross-sectional area for flow, accounting for the Fox #FT3 probe insertion. Note that the 2.5” nominal diameter stack was only used for the calibration of some of the Fox #FT3 devices and was not used for in-field measurements during the study.

Nominal Stack Diameter (in)	Stack Area (in^2)	Area Obstructed by Probe (in^2)	Unobstructed Area (in^2)
2	3.33	0.57	2.76
2.5	4.79	0.67	4.11
3	7.39	0.82	6.57
6	26.07	1.50	24.6
8	49.0	2.03	47.0

Thus, the instrument reported flow in standard cubic feet per hour (scf/h) was calculated based on the instrument reported velocity and the cross-sectional area available for flow through the stack or pipe:

$$scf/h_{inst} = v_{inst} * \frac{0.82}{v_m/v_{max}} * \frac{A_c}{144} \quad \text{(Equation S2-2)}$$

where v_{inst} is the instrument reported velocity in feet per hour, v_m/v_{max} is the ratio of measured velocity to center-line velocity (Table S2-1), and A_c is the unobstructed cross-sectional area of the stack or pipe in square inches (Table S2-2). The overall factor converting instrument reading to volumetric flow for each stack and pipe size is summarized in Table S2-3.

Table S2-3. Overall conversion factor for velocity measurement (ft/h) to flow rate (scf/h) for each stack and pipe size used in the project. Note that the 2.5" nominal diameter stack was only used for the calibration of some of the Fox #FT3 devices and was not used for in-field measurements during the study.

Nominal Stack Diameter (in)	Factor (B)
2	0.0169
2.5	0.0246
3	0.0390
6	0.143
8	0.273

The Fox FT#3 flow measurement devices were calibrated on pipes with sizes that were not necessarily the same as those utilized in the field measurements for unloadings. The probes were calibrated by the manufacturer by sending a known volume of methane through a pipe of known diameter and cross sectional area. For this study, calibrations were made on different Fox #FT3 instruments using the pipes specified as 2.5" and 3" nominal diameter in Tables S2-1 and S2-2. Thus, the flow rate calculated by the instrument (using a pipe which was typically a different diameter than the pipe used for calibration) had to be scaled by the ratio of the factor (Table S2-3) for the field pipe to the calibration pipe.

In addition, the Fox #FT3 instruments were calibrated by the manufacturer (Fox Thermal Instruments) using pure methane; instrument flow rates were corrected to account for the measured gas compositions, which varied from site to site. Because the flow meter measurement is based on thermal conductivity, the composition correction was based on the relative thermal conductivities of the gas at each site and the pure methane used as a calibration gas.

$$scf/h = scf/h_{inst}\left(\frac{k_{CH4}}{k_{gas}}\right)\left(\frac{B_{field}}{B_{cal}}\right) \quad \text{(Equation S2-3)}$$

where scf/h_{inst} is the raw instrument flow rate reading in standard cubic feet per hour, k_{CH4} is the pure component thermal conductivity (W/m*K) for methane at standard conditions (70ºF and 14.7 psia), and k_{gas} is the thermal conductivity of the gas sampled at standard conditions. The B factors are the values in Table S2-3, which convert the measured velocity to a flow rate. The thermal conductivity of the sampled gas (k_{gas}) was calculated as a molar weighted average:

$$k_{gas} = \sum_{i=1}^{7} k_i n_i \text{ (Equation S2-4)}$$

where n_i is the mole fraction of species i in the gas sample for the site and k_i is the pure component thermal conductivity of the species (http://webbook.nist.gov/chemistry/fluid/) under standard conditions. For this work, the pure component species considered were methane, ethane, propane, nitrogen, air, and carbon dioxide. All higher hydrocarbons with a carbon count of four or greater were lumped with butane for purposes of the gas composition correction.

Species	Thermal Conductivity (W/m*K)
Methane	0.033759
Ethane	0.020491
Propane	0.017884
Butane +	0.016181
Nitrogen	0.025473
Carbon Dioxide	0.016331

Table S2-4. Thermal conductivity of measured species at standard conditions (14.7 psia and 70ºF).

S3. Unloading emission measurements

Table S3-1. Unloading emissions from wells with automatically triggered plunger lifts

Well Characteristics							Emissions Data				
Well	Region	Vertical or horizontal well	Gas production rate (scf/day)	Water Production Rate (BBL/day)	Oil Production Rate (BBL/day)	Methane in produced gas (%)	Methane emitted per event (scf)	Events sampled	Average event duration (s)	Events per year for well reported by operator	Emissions per year for well based on events reported by operator (thousands of scf methane)
UBB 42 0101	RM	Vertical	170,000	0.10	0.10	75.7	914	6	147	1982	1810
UBB 42 0201	RM	Vertical	100,000	0.25	1.00	78.7	8,621	2	1208	1069	9220
UBB 42 0401	RM	Vertical	200,000	0.05	0.10	81.9	64	7	389	2546	163
UBB 42 0501	RM	Vertical	140,000	0.25	0.25	82.9	659	18	130	606	399
UBB 42 0601	RM	Vertical	140,000	ND	ND	83.4	7,278	5	1208	2686	19500
UBB 42 0701	RM	Vertical	170,000	0.50	0.50	81.1	103	9	276	184	19
UBB 42 0801	RM	Vertical	155,000	0.50	0.50	80.5	1,695	3	433	2048	3470
UBB 42 0901	RM	Vertical	150,000	1.00	2.80	91.5	91	26	70	964	88*
UBB 42 1001	RM	Vertical	162,000	0.50	0.02	91.5	209	5	36	715	149
UBB 42 1101	RM	Vertical	175,000	ND	ND	80.0	1,534	76	262	1011	1550
UBB 42 1201	RM	Vertical	90,000	0.10	ND	80.4	611	22	617	573	350
UBB 43 0101	RM	Vertical	180,000	ND	ND	78.5	1,296	16	177	2873	3720
UBB 43 0301	RM	Vertical	190,000	0.50	0.50	81.7	64	6	137	4698	301
UEY 41-0101	MC	Vertical	38,000	1.00	0.00	97.8	312	4	400	6570	2050
UEY 41-0201	MC	Vertical	90,000	1.00	ND	97.8	129	2	274	2389	308
UEY 41-0301	MC	Vertical	129,000	1.00	ND	97.8	215	4**	191	7509	1614
UEY 41-0401	MC	Vertical	107,000	0.50	0.00	97.8	549	1	206	3893	2137
UBB 50 2601	RM	Vertical	54,000	0.75	0.00	76.8	915	2	317	643	588
UBB 50 2701	RM	Vertical	47,000	0.19	0.00	77.7	1,998	1	849	4252	8495
UBB 50 2801	RM	Vertical	32,000	0.21	0.00	78.2	56	25	33	4051	227
UBB 50 2901	RM	Vertical	15,000	0.30	0.00	83.0	993	14	90	2482	2464
UBB 50 3001	RM	Vertical	26,000	0.16	0.00	81.9	237	7	692	650	154
UBB 50 3101	RM	Vertical	46,000	0.23	0.00	80.6	58	17	73	1963	114
UBB 50 3201	RM	Vertical	46,000	0.16	0.00	76.6	1,325	15	309	528	700
UEF-49-0501	GC	Vertical	18,000	0.25	0.06	82.4	428	2	123	4238	1810

*Well measurement was excluded from national estimates of scf methane per event due to data cropping in the instrument time series.
**The fourth event (of five measured) at the well was excluded from analysis of the well due to field notes indicating a measurement error during that period.
***ND indicates that data could not be provided by the operator.

Table S3-2. Unloading emissions from wells with manually triggered plunger lifts

Well Characteristics							Emissions Data				
Well	Region	Vertical or horizontal well	Gas production rate (scf/day)	Water Production Rate (BBL/day)	Oil Production Rate (BBL/day)	Methane in produced gas (%)	Methane emitted per event (scf)	Events sampled	Average event duration (s)	Events per year for well reported by operator	Emissions per year for well based on events reported by operator (thousands of scf methane)
UBB-45-0101	RM	Vertical	20,000	0.70	2.50	77.4	9,674	1	727	30	290
UBB-45-0201	RM	Vertical	20,000	0.00	8.00	77.4	11,678	1	1,529	50	584
UBB-45-0202	RM	Vertical	35,000	0.00	12.00	77.4	11,783	1	1,303	50	589
UBB-45-0203	RM	Vertical	10,000	3.45	1.53	77.4	4,703	1	1,522	50	235
UBB-45-0204	RM	Vertical	25,000	0.00	10.00	77.4	3,641	1	1,708	50	182
UBB-45-0301	RM	Vertical	16,000	0.25	4.25	77.4	5,612	1	1,416	2	11
UBB-45-0302	RM	Vertical	45,000	0.25	3.75	77.4	4,008	1	1,219	2	8
UBB-45-0401	RM	Vertical	25,000	0.15	2.35	77.4	16,852	1	3,714	2	34
UBB-45-0501	RM	Vertical	13,000	0.50	2.00	77.4	8,057	1	3,847	5	40
UBB-47-0301	GC	Vertical	80,000	0.20	0.30	86.5	3,937	1	7,672	2	8
UDN-44-0203	RM	Vertical	125,000	1.98	1.64	88.8	4,737	1	443	3	14
UDN-44-0304	RM	Vertical	43,000	0.88	0.18	90.7	14,069	1	540	6	84
UDN-44-0405	RM	Vertical	343,000	3.09	4.42	89.1	8,289	1	417	3	25
UDN-44-0506	RM	Vertical	231,000	2.43	2.04	89.9	6,459	1	528	1	6
UDN-44-0507	RM	Vertical	248,000	2.60	2.19	88.4	8,639	1	588	*	
UEF-02-0201	MC	Vertical	41,000	0.65	0.20	81.1	8,290	1	2,271	13	108
UEF-02-0202	MC	Vertical	15,000	1.30	0.00	84.3	6,083	1	5,637	10	61
UEF-02-0203	MC	Vertical	24,000	0.10	0.20	82.5	11,958	1	2,864	12	143
UEF-02-0204	MC	Vertical	35,000	0.60	0.20	78.4	6,272	1	1,780	8	50
UEF-02-0205	MC	Vertical	24,000	0.32	0.87	81.9	14,570	1	3,458	8	117
UEF-02-0206	MC	Vertical	38,000	0.50	0.10	85.6	21,255	1	4,996	4	85
UJR-46-0101	RM	Vertical	86,000	9.00	0.30	86.4	1,665	1	1,011	5	8
UJR-46-0401	RM	Vertical	36,000	3.00	0.10	86.4	993	1	231	6	6
UJR-46-0501	RM	Vertical	37,000	9.00	0.10	86.4	6,744	1	560	16	108
UJR-46-0601	RM	Vertical	30,000	6.00	0.00	86.4	1,220	1	198	1	1
UJR-46-0701	RM	Vertical	34,000	4.00	0.10	86.4	1,261	1	339	11	14
UJR-46-0801	RM	Vertical	51,000	8.00	0.20	86.4	22,364	1	3,926	3	67
UJR-46-1001	RM	Vertical	110,000	33.00	0.20	86.4	8,101	1	3,149	2	16
UJR-46-1101	RM	Vertical	118,000	18.00	0.65	86.4	2,663	1	559	15	40

UJR-46-1201	RM	Vertical	19,000	2.00	0.50	86.4	21,060	1	1,289	8	168
UMB-06-0101	MC	Vertical	23,000	ND	ND	83.0	4,805	1	790	2	10
UMB-06-0201	MC	Vertical	22,000	ND	ND	81.9	759	1	131	10	8
UMB-06-0301	MC	Vertical	12,000	ND	ND	81.8	4,279	1	2,183	2	9
UMB-06-0401	MC	Vertical	226,000	ND	ND	81.5	403	1	169	1	0.5
UMB-06-0501	MC	Vertical	4,000	ND	ND	82.1	1,311	1	474	2	3
UMB-06-0601	MC	Vertical	30,000	ND	ND	82.5	1,245	1	387	10	12
UMB-06-0901	MC	Vertical	38,000	ND	ND	77.5	1,862	1	688	10	19
USH-42-0301	AP	Horizontal	900,000	2.00	ND	97.3	223	1	86	7	2
USH-45-0101	RM	Vertical	160,000	2.70	0.00	87.8	18,277	1	1,314	2	37
USH-45-0103	RM	Vertical	168,000	1.70	0.00	87.8	47,119	1	1,181	3	141
USH-45-0105	RM	Vertical	87,000	2.00	0.00	87.8	18,724	2	2,997	15	281
USH-45-0201	RM	Vertical	119,000	6.10	0.00	87.8	26,668	1	1,900	1	27
USH-45-0202	RM	Vertical	166,000	22.10	0.10	87.8	49,273	1	1,447	11	542
USH-45-0203	RM	Vertical	151,000	21.00	0.10	87.8	15,834	2	1,638	39	618
UTG-44-0201	AP	Vertical	6,000	0.20	0.00	95.7	4,313	1	10,214	20	86
UTG-44-0301	AP	Vertical	10,000	0.10	0.00	95.7	8,622	1	2,609	24	207
UTG-44-0401	AP	Vertical	4,000	2.40	0.00	95.7	4,398	1	3,213	24	106
UTG-44-0501	AP	Vertical	10,000	2.40	0.00	95.7	3,534	1	1,240	24	85
UTG-44-0601	AP	Vertical	17,000	3.00	0.00	95.7	3,964	1	1,060	52	206
UTG-44-0701	AP	Vertical	6,000	1.80	0.00	95.7	10,542	1	9,807	12	127

*No report on frequency of venting; emission measurements were used in calculating average emissions per event, assuming events were less than 100 per year.

** ND indicates that data could not be provided by the operator.

Table S3-3. Unloading emissions from wells without plunger lifts

Well Characteristics							Emissions Data					
Well	Region	Vertical or horizontal well	Gas production rate (scf/day)	Water Production (BBL/day)	Oil Production (BBL/day)	Methane in produced gas (%)	Methane emitted per event (scf)	Events sampled	Average event duration (s)	Events per year for well reported by operator	Emissions per year for well based on events reported by operator (thousands of scf methane)
UBB-47-0101	GC	Vertical	150,000	0.30	1.00	92.7	555	2	1,518	2	1
UBB-47-0201	GC	Vertical	100,000	0.40	1.80	80.7	6706	2	3,417	4	27
UBB-47-0401	GC	Vertical	100,000	3.30	1.00	86.5	2745	1	2,104	1	3
UCG-03-0101	GC	Vertical	162,078	1.20	0.00	96.1	12237	1	6,762	48	587
UCG-03-0102	GC	Vertical	155,279	4.50	0.00	96.1	13761	1	6,016	6	83
UCG-03-0103	GC	Vertical	160,791	2.00	0.00	96.1	24085	1	7,919	12	289
UCG-03-0201	GC	Vertical	153,467	2.00	0.03	93.3	16029	1	3,952	3	48
UCG-03-0202	GC	Vertical	269,018	4.00	0.00	93.3	24544	1	4,739	3	74
UCG-03-0203	GC	Vertical	167,000	2.00	0.00	96.1	16056	1	2,504	185	1975
UCG-03-0204	GC	Vertical	43,748	2.00	0.00	93.3	9942	1	5,120	81	805
UCG-03-0301	GC	Vertical	102,050	1.00	0.00	93.3	21342	1	9,819	27	576
UCG-03-0302	GC	Vertical	151,000	4.00	0.00	96.1	11436	1	4,308	151	1269
UCG-03-0401	GC	Vertical	123,017	2.00	0.00	96.1	10696	1	1,270	9	96
UCG-03-0402	GC	Vertical	67,718	0.40	0.00	96.1	16487	1	2,662	45	742
UEY-41-0601	MC	Horizontal	400,000	1.00	0.00	95.2	73417	1	11,782	1	73
UMB-06-0701	MC	Vertical	25,000	1.00	0.50	74.3	3509	1	1,841	5	18
UMB-06-0801	MC	Vertical	20,000	0.50	0.50	72.8	6460	1	3,580	3	19
UMB-06-1101	MC	Vertical	21,000	ND	ND	81.3	6083	1	1,021	12	73
UMB-06-1201	MC	Vertical	4,787	ND	ND	78.4	1951	1	964	1	2
UMD-43-0101	AP	Horizontal	974,277	10.00	0.00	96.9	1880	1	2,059	12	23
UMD-43-0201	AP	Horizontal	746,890	7.00	0.00	97.0	10940	1	2,996	15	164
USH-42-0501	AP	Horizontal	230,000	3.22	0.00	97.3	1423	1	1,252	6	9
USH-45-0102	RM	Vertical	93,000	1.00	0.00	87.8	9409	1	2,411	19	179
USH-45-0104	RM	Vertical	86,000	2.00	0.00	87.8	20967	1	805	5	105
USH-47-0101	MC	Horizontal	365,200	1.50	0.00	95.3	41919	1	10,009	4	168
USH-47-0201	MC	Horizontal	224,404	0.95	0.00	96.7	75974*	2	14,525	95	7218
USH-47-0301	MC	Horizontal	147,231	0.37	0.00	96.7	57793	1	16,161	101	5837
USH-47-0401	MC	Horizontal	182,770	1.30	0.00	97.5	27055	1	7,766	84	2273
USH-47-0601	MC	Horizontal	258,500	0.40	0.00	94.8	47037	1	3,971	70	3293

USH-47-0701	MC	Horizontal	246,356	0.62	0.00	97.8	134834	1	9,741	45	6068
USH-47-0801	MC	Horizontal	88,217	0.10	0.00	97.9	97937	1	5,530	2	196
UTG-44-0101	AP	Vertical	10,000	10.00	2.40	95.7	4007	1	629	12	48

*Of the two events measured for this well, one was done without the well being shut-in before the event; since liquids removal was low during this unloading, a second unloading, was done 3 days later with the well shut-in between events. According to the well operator this shut in is required for approximately 6 of the 95 events during a year. The average emissions is therefore a weighted average of the first event (typical of 89 of the 95 events per year) and the second, much larger event (6 of 95 events per year)

**ND indicates that data could not be provided by the operator.

S4. Statistical analyses of variability in unloading emission measurements

The emission measurement data were combined with well characteristics reported by the host companies to identify possible explanatory variables for the frequency of unloading events and annual unloading emission totals. A natural logarithm (ln) transform was applied to the total gas annual methane emission values owing to the skewness in this variable. The logarithm transform maintains the ordering of observations but reduces the influence of the larger values on the calculated statistics. The statistical Pearson linear correlations and linear regressions between annual methane emissions and number of events per year with several other statistical variables were calculated.

The correlation is a number between -1.0 and 1.0 that is a measure of the linear association between two variables. A positive correlation between two variables suggests that generally if one observation of the first variable is higher than the average for that variable, then the corresponding value of the second variable is also higher than average. A negative correlation between two variables suggests that generally if the first variable is higher than the average for that variable, then the corresponding value of the second variable is lower than average. Care must be used in concluding that there is a causal relationship underlying a high positive or negative correlation. One confounding factor could be that there are outliers in the data that have disproportionate impact on average values and therefore in producing a calculated correlation. The natural logarithm transform used on the annual methane emission total helps to address this. Care must also be used in drawing a conclusion about a correlation close to zero, as a strong relation could exist between variables with correlation = 0.0 that is nonlinear.

Associated with a calculated linear correlation is a probability value (p-value) that represents the approximate probability that a correlation as large as the one calculated with the sampled data could have been the result of a random set of data with no actual underlying correlation. An individual correlation result with a p-value of 0.05 or less means that the probability that a value as large as the calculated correlation would result if the variables had a random association is small, and thus it can be concluded that the association is likely not random.

The correlations were calculated between company reported *Annual Venting Events*, measured *Average Sampled Event Duration*, estimated *Annual CH_4 Emissions (Mscf)*, and the natural logarithm of *Annual CH_4 Emissions (Mscf), and* 7 well characteristic variables. The variables are shown in Table S4-1. The correlations with p-values below 0.05 are shown in Table S4-2. Although several pairings of emissions variables and well variables appear to be statistically significant, the scatter plot graphs and linear fits suggest most of these relationships do not explain more than a few percent in the variability of emissions, which is the correlation-squared or R^2 in linear regression. Well *Total Depth* is an exception, as shown in the line fit graph in Figure S4-1. *Total Depth* explains 6% (R^2 = 0.41) of the variability in *ln(Annual CH_4 Emissions)* and there is a visible downward trend in the data suggesting emissions decrease with well depth. This may or may not be related to a tendency in deeper wells being newer and thus less prone to unloadings. When the analysis is restricted to plunger lift wells only, the *Well Depth* regression is significant at $p < 0.0001$ and the R^2 rises to 27%. Also shown in Figure S4-1 is the ln(*Annual CH_4 Emissions)* versus *Annual Venting Events* for automated and manual plunger lift wells (R^2=43%). The variable for well *Age* was correlated with the estimated number of *Annual*

*Venting Events*and statistically significant and positively correlated with *ln(Annual CH_4 Emissions).*

Table S4-1. List of study measurements and estimates compared with reported well characteristics

Study measurements	**Well characteristics**
Event duration	Surface flow line pressure
Events per year	Static Shut-in pressure
Whole Gas SCF per Year	Total Depth
Ln(Whole Gas SCF per Year)	Production SCF per day
	Volume (depth * diameter * diameter / 4)
	Age of well

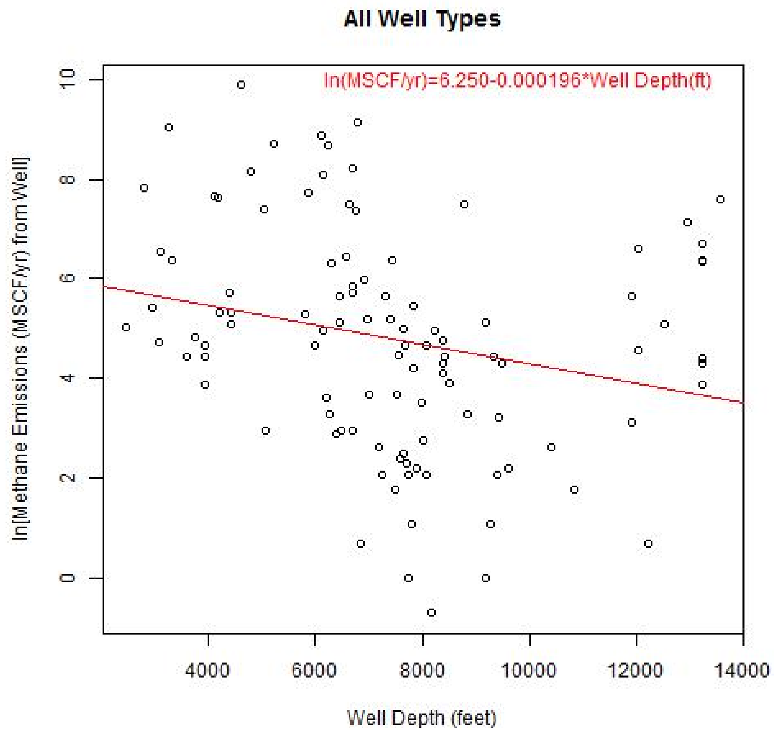
Table S4-2 Pairwise linear correlations

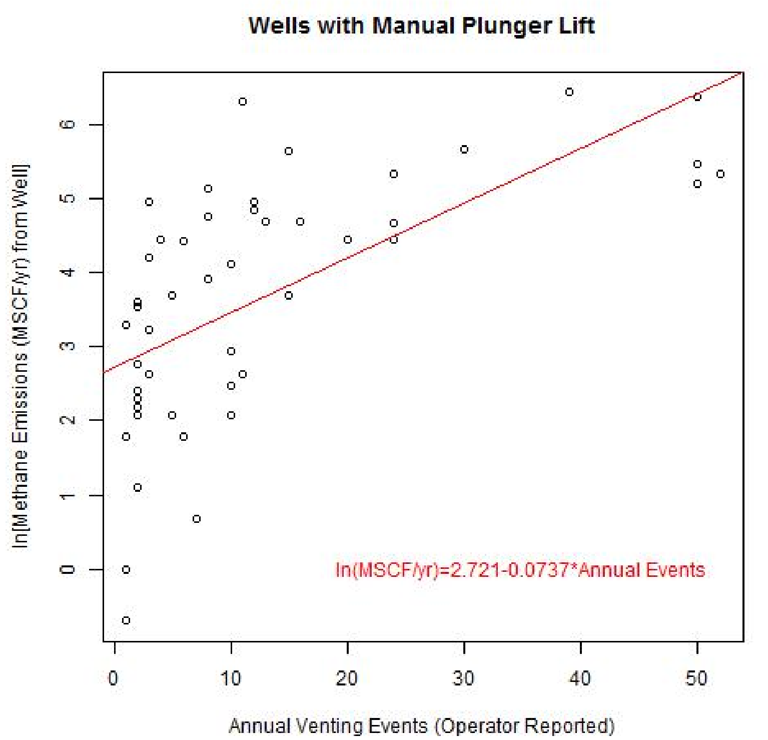
Y Variable	**X Variable**	**Number of paired obs.**	**Linear correlation**	**R^2**	**p-value**
Annual CH_4 Emissions (Mscf)*	Well Depth (ft)	106	-0.2193	4.8%	0.0239
Annual CH_4 Emissions (Mscf)	age	106	0.1990	4.0%	0.0409
Annual CH_4 Emissions (Mscf)	Measured CH_4 Emitted / Event (scf)	106	0.2188	4.8%	0.0242
Annual CH_4 Emissions (Mscf)	Annual Venting Events	106	0.3258	10.6%	0.0007
ln(Annual CH_4 Emissions)	Well Depth (ft)	106	-0.2415	5.8%	0.0126
ln(Annual CH_4 Emissions)	volume	104	-0.1961	3.8%	0.0460
ln(Annual CH_4 Emissions)	Average Sampled Event Duration (s)	106	0.2285	5.2%	0.0185
ln(Annual CH_4 Emissions)	Measured CH_4 Emitted / Event (scf)	106	0.3024	9.1%	0.0016
ln(Annual CH_4 Emissions)	Annual Venting Events	106	0.4475	20.0%	0.0001
Annual Venting Events**	Well Depth (ft)	106	-0.3731	13.9%	0.0001
Annual Venting Events	Shut-In Pressure (psig)	41	-0.3517	12.4%	0.0242
Annual Venting Events	volume	104	-0.2888	8.3%	0.0029
Annual Venting Events	Average Sampled Event Duration (s)	106	-0.2808	7.9%	0.0036
Annual Venting Events	Surface Line Pressure (psig)	106	-0.2593	6.7%	0.0073
Annual Venting Events	Measured CH_4 Emitted / Event (scf)	106	-0.2253	5.1%	0.0202
Annual Venting Events	Annual CH4 Emissions (Mscf)	106	0.3258	10.6%	0.0007
Annual Venting Events	ln(Annual CH_4 Emissions)	106	0.4475	20.0%	0.0001
Average Sampled Event	Annual Venting Events	106	-0.2808	7.9%	0.0036

Duration (s)					
Average Sampled Event Duration (s)	ln(Annual CH_4 Emissions)	106	0.2285	5.2%	0.0185
Average Sampled Event Duration (s)	CH_4 in Produced Gas (%)	107	0.4349	18.9%	0.0001
Average Sampled Event Duration (s)	Measured CH_4 Emitted / Event (scf)	107	0.6377	40.7%	0.0001
Measured CH_4 Emitted / Event (scf)	age	107	-0.2696	7.3%	0.0050
Measured CH_4 Emitted / Event (scf)	Annual Venting Events	106	-0.2253	5.1%	0.0202
Measured CH_4 Emitted / Event (scf)	Annual CH_4 Emissions (Mscf)	106	0.2188	4.8%	0.0242
Measured CH_4 Emitted / Event (scf)	ln(Annual CH_4 Emissions)	106	0.3024	9.1%	0.0016
Measured CH_4 Emitted / Event (scf)	CH_4 in Produced Gas (%)	107	0.3756	14.1%	0.0001
Measured CH_4 Emitted / Event (scf)	Average Sampled Event Duration (s)	107	0.6377	40.7%	0.0001

*Annual Methane Emissions (Mscf) based on events reported by operator
**Annual Count of Venting Events reported by operator

Figure S4-1 Examples of linear fits for two significantly related variables (upper: ln annual methane emissions vs. well depth for all wells (R^2=6%); lower: ln annual methane emissions vs. frequency of unloading for manual plunger lift wells (R^2=43%).





Additional statistical analyses were done, comparing the observed whole gas emissions per event to emissions per event that would be predicted based on EPA emission estimation methods described in Title 40 of the Code of Federal Regulations, Part 98 (40 CFR Part 98.233 (f)). Calculation Methodology 2 was used for liquids unloading without plunger lift and Calculation Methodology 3 was used for liquids unloading with plunger lift. Briefly, these emission estimation methods assume that an unloading event vents, at a minimum, the entire volume of the well bore and that the well bore is entirely filled with gas at the shut-in pressure.

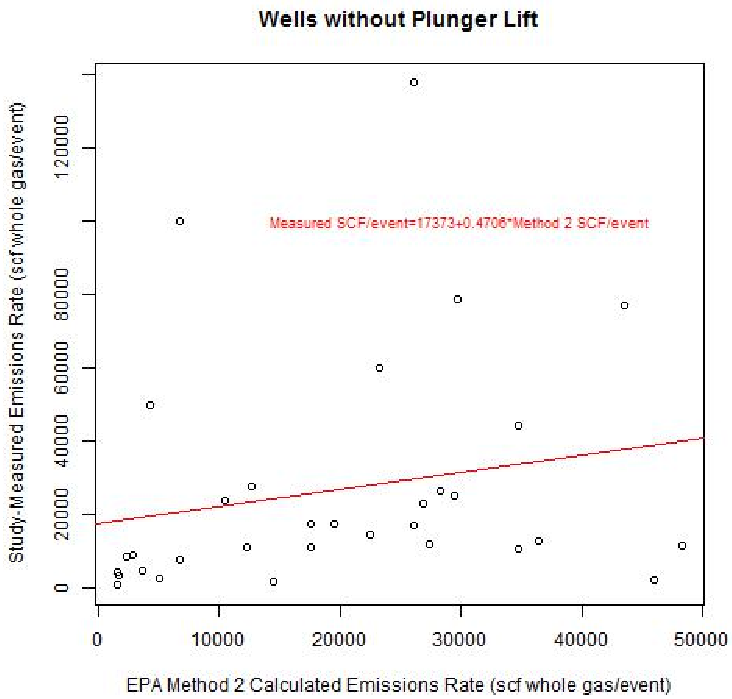
Using Method 2 for a non-plunger lift well, if the event lasts more than 60 minutes, the vent rate for the period after 60 minutes is assumed to be at the production rate. The comparisons with the emission estimation Method 2 were done for all non-plunger lift wells using data for surface line pressure. Shut-in pressure could also be used in this calculation but was only available for a subset of wells.

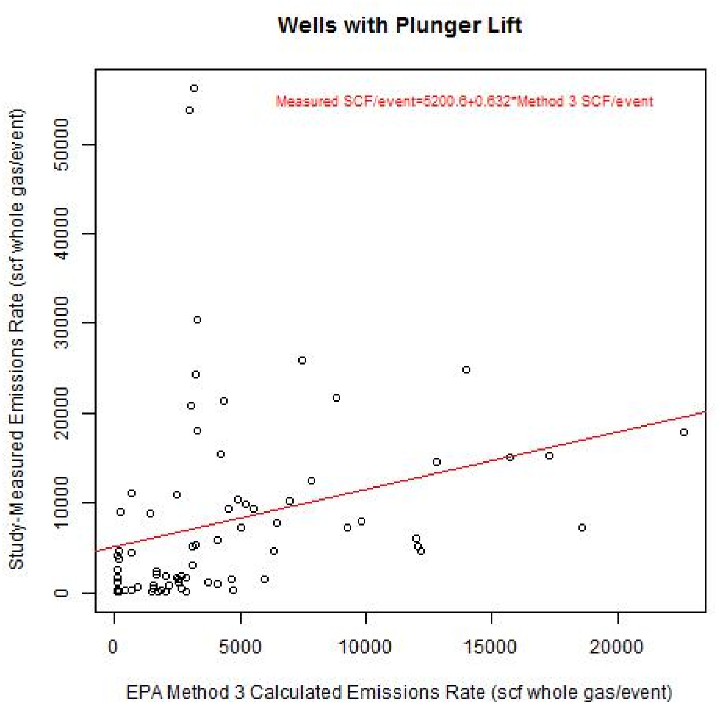
Using Method 3 for a plunger lift well, if the event lasts more than 30 minutes, the vent rate for the period after 30 minutes is assumed to be at the production rate. Under Method 3 for a plunger lift well a surface line pressure is used, and the necessary data were provided for all plunger lift wells.

For 32 non-plunger lift wells, the observations comparing measured whole gas event emissions and EPA Method 2 estimates appear to have random agreement and the correlation between the paired values ($r = 0.21$) is not statistically significant ($p = 0.26$). However, in a paired t-test comparison, the mean Method 2 estimate is not statistically significantly different ($p = 0.52$) from the mean non-plunger well measurements. A comparison of the whole gas emissions per event to the Method 2 estimation for non-plunger lift wells appears in Figure S4-2, and resulting slope (0.47) is not statistically significant, with $r^2 = 4\%$.

For 75 wells with plunger lifts, the whole gas emission estimates are statistically significantly correlated to the actual study measurements ($r = 0.28$, $p=.015$). The paired t-test comparison shows that the mean Method 3 estimate (4,500 scf/event) is statistically significantly different ($p = 0.004$) from the mean of plunger well measurements (8,000 scf/event). Figure S4-2 shows the comparison. The resulting slope (0.63) is statistically significant, with $r^2 = 8\%$.

Figure S4-2 Comparison of whole gas emission predictions using EPA emission estimation methods to observed whole gas emissions per event for wells without plunger lift (upper, r^2=4%), and with plunger lift (lower, r^2=8%).





S5. Estimates of emissions from gas well liquid unloadings in the United States

Emission measurements from a limited set of samples can be used to estimate national emissions by multiplying the average emission measurement by the number of times that emission occurs on the national scale. Often the emission measurement is referred to as an "emission factor" or EF, and the data used to scale up the emissions is called the activity factor (AF). Emissions are calculated as:

$$EF_i * AF_i = ER_i \qquad \text{(Equation S5-1)}$$

where:

EF_i = Emission Factor for region i

AF_i = Activity Factor for region i

ER_i = resulting Emission Rate total for region i

For this work, the activity factors are regional counts of natural gas well unloading events. The activity data and the emission factor data are stratified at two levels. First, wells are classified as either with or without plunger lift. Then, within each well category (with or without plunger lift) wells are grouped based on the frequency of unloadings (events per year). The emission factor strata for which activity data are needed are shown in Table S5-1.

Table S5-1. Categories of wells for which emissions were measured

Well type (Annual Frequency of events)	Measured EF, scf methane per event (95% confidence range)
Plunger Wells (events<100)	9,650 (6,900-12,400)
Plunger Wells (events≥100)	1,260 (500-2,100)
Non Plunger Wells (events<10)	21,500 (9,600-37,800)
Non Plunger Wells (10≤events<50)	24,100 (8,700-50,400)
Non Plunger Wells (50≤events<200)	35,000 (18,700-53,000)
Non Plunger Wells (events≥200)	Not measured, assume 35,000 [see main text] (18,700-53,000)

Activity Data

The primary source of activity data used in this work is a survey of unloading event counts collected from companies that participated in this work. These survey data were supplemented by data on well counts from the GHG Mandatory Reporting Program, for reporting year 2012, released in 2013 (referred to here as EPA 2012 GHGRP) and the 2012 GHG National Emission Inventory, released in 2014 (referred to here as the 2012 GHG NEI).

The EPA 2012 GHG NEI reports that 60,810 natural gas wells have liquids unloadings, out of an estimated 470,913 natural gas wells in the United States (not including oil wells with associated gas production). This represents 13% of gas wells in the EPA 2012/2014 GHG NEI. Of these 60,810 wells, 23,503 are reported as having plunger lifts and 37,307 are reported as not having plunger lifts.

More granular and detailed data is available as part of the EPA 2012 GHGRP. All operators of U.S. upstream petroleum and natural gas production are required to report under the GHGRP, so long as their total emissions from all sources exceeds 25,000 MT CO_2e/yr for an entire basin. EPA estimated in the original publication of the Rule that more than 85% of all GHG emitters would have to report, though the percentage may be higher in the oil and gas production sector, given that reporting facilities are defined as large basins. The latest data available from the GHG Mandatory Reporting rule is published in the EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT) system (http://ghgdata.epa.gov/ghgp/main.do) and data for individual facilities can be downloaded from that system. Data from reporting year 2012 (released in October 2013) was the latest data available at the time this work was completed. FLIGHT data from reporting year 2012 shows 58,663 wells that report unloading emissions. Of these 58,663 wells from FLIGHT, 32,225 are estimated to have plunger lifts and an estimated 26,438 do not have plunger lifts. This agrees reasonably well with the EPA NEI estimates for total well count (58,663 from FLIGHT as compared to 60,810 from the GHG NEI), however, the fractions of plunger and non-plunger wells differ for the two data sets. In this work, the fractions of plunger and non-plunger wells from the 2012 GHGRP will be used to estimate national emissions, based on the assumption that these data are based on more recent assessments of the prevalence of plunger lifts. A sensitivity analysis is presented at the end of this section to assess the effect of this assumption on national emission estimates.

While this work uses total well counts from the 2012 GHGRP FLIGHT data in estimating national emissions, event counts will be based on data from a survey of companies participating in this work. One reason for using survey data for event counts is the lack of complete data on event frequency for non-plunger wells in the 2012 GHGRP FLIGHT data. While it may be feasible to estimate these data from partial reporting in the 2012 GHGRP, this would require making assumptions regarding the representativeness of partial reporting. A second reason for using the survey data collected in this work, rather than GHGRP FLIGHT data for event counts, was apparent quality assurance issues in event counts in the GHGRP FLIGHT data. Specifically, the study team's interpretation of the event reports in the GHGRP suggested very high frequencies of events for some non-plunger wells. These event frequencies appeared to the study team to be physically unreasonable (thousands of events per year for wells that are almost exclusively manually unloaded) and inconsistent with the survey data from companies.

Since event counts for plunger and non-plunger wells are either partially reported or of uncertain quality in the FLIGHT data, the companies participating in this study volunteered data on unloading emissions that they had released to the EPA GHGRP for reporting year 2013. Eight of the ten participants were able to provide data. The participant company data underwent quality assurance review and was then used to determine average event frequencies for the categories of non-plunger and plunger lift wells. The event counts for non-plunger lift wells are shown in Table S5-2 (national totals). Table S5-3 reports regional distributions of event counts for plunger and non-plunger wells. The data in Table S5-3 indicate that event count distributions in the four regions considered in this work are all similar to national averages for non-plunger wells, but since detailed regional data are available, they will be used in estimating emission event counts in this work.

As an example of how event counts were estimated in Table S5-2, consider the national total for non-plunger wells with less than 10 events per year. In the survey 6,378 of the 7481 wells without plunger lift (85%, see Table S5-2) had less than 10 events per year. It therefore is assumed that 85% of the 26,438 wells without plunger lift nationally will have less than 10 events per year, with an average of 2.93 events per well (see Tables S5-3, S5-4). This results in an estimate of 66,000 events for these low event frequency wells in Table S5-2. A total event count for all wells without plunger lifts reported through the GHGRP is estimated as 170,000 events, based on national average data, as shown in Table S5-2. If the averaging is done on a regional basis, as shown in Table S5-4, the national event count is estimated as 177,000 events. The regional estimate of event counts was used to produce a national methane emission estimate of 4.4 bcf/yr, as shown in Table S5-5.

Table S5-2. Activity data for wells without plunger lifts, based on surveys of participating companies using nationally averaged data

Well Type Strata	**Total Number of events**	**% of events reported by participants**	**Number of Venting Wells**	**% of wells reported by participants**	**National Event Count if Participant Event Counts are scaled up by number of wells**
Non Plunger Wells (events<10)	18,691	39	6,378	85	66,000
Non Plunger Wells (10≤events<50)	20,593	43	1,016	14	73,000
Non Plunger Wells (50≤events<200)	5,969	12	79	1	21,000
Non Plunger Wells (events≥201)	2,705	6	8	0.1	9,600
Total	***47,958***	***100***	***7,481***	***100***	***170,000***

Table S5-3. Regional distributions of event counts, based on surveys of participating companies

Company Data Well type (Annual Frequency of events)	AP			GC			MC			RM			Total		
	# of wells	#of events	Events/ Well	# of wells	#of events	Events/ Well	# of wells	#of events	Events/ Well	# of wells	#of events	Events/ Well	# of wells	#of events	Events/ Well
Non Plunger lift wells															
0-10	744	2,327	3.13	1,520	4,455	2.93	2,315	6,831	2.95	1,799	5,078	2.82	6,378	18,691	2.93
11-50	179	3,826	21.4	180	3,491	19.4	461	9,757	21.1	196	3,519	18.0	1,016	20,593	20.3
51-200	19	1,270	66.8	11	915	83.2	41	3,177	77.5	8	607	75.9	79	5,969	75.6
201+	0	0	-	1	355	355	7	2,350	336	0	0	-	8	2,705	338
Plunger lift wells															
0-99	42	302	7.19	423	2,237	5.29	857	4,419	5.16	3,845	60,282	15.7	5,167	67,240	13.01
100+	1	259	259	3	366	122	191	324,341	1,698	3,410	3,508,080	1,029	3,605	3,833,046	1,063

Table S5-4 Regional distributions of non-plunger well event counts, based on surveys of participating companies

Company Data Well type (Annual Frequency of events)	AP				GC				MC				RM				
	# of wells	% of wells	Events/ Well	Region Event count	# of wells	% of wells	Events/ Well	Region Event count	# of wells	% of wells	Events/ Well	Region Event count	# of wells	% of wells	Events/ Well	Region Event count	National event count
0-10	7,812	79%	3.13	19,300	3,855	88.8%	2.93	10,000	8,219	82.0%	2.95	19,900	6,552	89.8%	2.82	16,600	65,800
11-50		19%	21.4	31,700		10.5%	19.4	7,900		16.3%	21.1	28,400		9.8%	18.0	11,500	79,500
51-200		2%	66.8	10,500		0.6%	83.2	2,100		1.5%	77.5	9,200		0.4%	75.9	1,990	23,800
201+		0%	-	0		0.06%	355	800		0.2%	336	6,800		-	-	-	7,600
Total		100%		62,000		100%		21,000		100%		64,000		100%		30,000	177,000

Table S5-5. National emission estimate for non-plunger lift wells

Well type (Annual Frequency of events)	Event count, events/yr	Measured EF, scf methane per event (95% confidence range)	Emissions, billion scf methane/yr (95% confidence range)
Non Plunger Wells (events<10)	65,800	21,500 (9,600-37,800)	1.4 (0.6-5.2)
Non Plunger Wells (10≤events<50)	79,500	24,100 (8,700-50,400)	1.9 (0.7-4.0)
Non Plunger Wells (50≤events<200)	23,800	35,000 (18,700-53,000)	0.8 (0.4-1.3)
Non Plunger Wells (events≥200)	7,600	Not measured, assume 35,000 [see main text] (18,700-53,000)	0.3 (0.1-0.4)
Total			4.4 (2.8-8.5*)

*Range assumes that emission factors for each frequency range are independent

Table S5-6. Regional distributions of plunger lift well counts, and high and low frequency wells used in making national emission estimates

Well type (Annual Frequency of events)	AP		GC		MC		RM Basin 580		RM excluding Basin 580	
	well count	$f_{high\ or\ low}$ freq. events	well count	$f_{high\ or\ low}$ freq. events	well count	$f_{high\ or\ low}$ freq. events	well count	$f_{high\ or\ low}$ freq. events	well count	$f_{high\ or\ low}$ freq. events
0-99	10,869	0.98	1,048	0.993	5,096	0.82	5,041	0.32	10,171	0.91
100+		0.02		0.007		0.18		0.68		0.09

National event counts for plunger wells were estimated with a slightly modified procedure. The modifications are necessary because the distribution of high event frequency wells (≥100 events/yr) is not uniform within the Rocky Mountain region. As shown in Table S5-6 and S5-7, Basin 580 in the the Rocky Mountain region has a much higher fraction of high frequency plunger lift unloadings than the rest of the region. Therefore, the total number of events associated with high and low frequency wells in the Rocky Mountain region was estimated using two sub-regions. As an example, the total number of plunger lift wells in Basin 580 of the Rocky Mountain region (from the GHGRP) was 5,041 (Table S5-6). Data from the company participant survey (Table S5-6) indicated that 68% of the plunger lift wells in Basin 580 had 100 or more events per year, leading to an estimate of 3,404 high frequency plunger lift wells in Basin 580 (Table S5-7). Similar calculations were done to estimate the number of low and high frequency wells in each region and sub-region. The event estimates are shown in Table S5-7, and suggest a total of 206,500 events/yr for low frequency wells and 6.56 million events/yr for high frequency wells. National emission estimates, based on 5 region averaging (AP, GC, MC, two RM sub-regions), are shown in Table S5-8.

Table S5-7. Activity data for wells with plunger lifts, based on surveys of participating companies

Well Type	**National Total Number of wells**	$N_{\text{low or high freq. events}, i}$ **(Average number of events per well)**	**Scaled total Number of events**
AP Plunger Wells (events<100)	10,616	7.19	76,300
GC Plunger Wells (events<100)	1,041	5.29	5,500
MC Plunger Wells (events<100)	4,167	5.16	21,500
RM Plunger Wells (events<100) (Basin 580 only) [RM without basin 580]	10,930 (1,637) [9,293]	 (31.2) [5.61]	103,200 (51,100) [52,100]
Total Plunger Wells (events<100) (5 regions)	26,754		206,500
AP Plunger Wells (events 100+)	253	259	65,500
GC Plunger Wells (events 100+)	7	122	900
MC Plunger Wells (events 100+)	929	1,698	1,577,400
RM Plunger Wells (events 100+) (Basin 580 only) [RM without basin 580]	4,282 (3,404) [878]	 (976) [1,819]	4,919,400 (3,322,300) [1,597,100]
Total Plunger Wells (events 100+) (5 regions)	5,471		6,563,200
National Total (5 regions)	32,225		6,769,700

Table S5-8. National emission estimate for plunger lift wells

Well type (Annual Frequency of events)	Event count, events/yr	Measured EF, scf methane per event (95% confidence range)	Emissions, billion scf methane/yr (95% confidence range)
Plunger Wells (events<100)	206,500	9,650 (6,900-12,400)	2.0 (1.4-2.6)
Plunger Wells (events≥100)	6,563,000	1,260 (500-2,100)	8.0 (3.3-13.8)
Total			10 (5.2-15.8*)

*Range assumes that emission factors for each frequency range are independent

Taken together, methane emissions from both plunger lift wells (Table S5-8) and non-plunger lift wells (Table S5-5) are 14.4 billion scf/yr (270 Gg). The 95% confidence range, assuming that the estimates for plunger lift wells and non-plunger lift wells are independent, is 10-21 billion scf/yr (190-400 Gg/yr).

A sensitivity analysis on national emission estimates was performed using alternative distributions of plunger and non-plunger wells in the national well count. The national emission estimates reported in Tables S5-5 and S5-8 are based on total counts of plunger and non-plunger lift wells from the 2012 GHGRP. If the data from the 2012 GHG NEI are used instead, the total emission estimates would scale based on the number of wells in each category. So, if the total plunger well count is reduced from 32,225 to 23,503, total estimated emissions from plunger lift wells would decrease to 7.3 bcf (10 bcf * 23,503/32,225). This decrease in plunger lift well emissions would be partially offset by increases in emissions from non-plunger wells. The count of non-plunger lift wells would increase from 26,438 to 37,307 and total estimated emissions from the non-plunger wells would increase to 6.2 bcf (4.4 bcf * 37,307/26,438). Overall, emissions from both plunger lift and non-plunger lift wells would decrease slightly from 14.4 bcf/yr to 13.5 bcf/yr.

An additional sensitivity analysis on estimates of national event counts was performed using data from a survey on liquid unloadings performed by the American Petroleum Institute and America's Natural Gas Alliance (API/ANGA, 2012). The data in the API/ANGA report on numbers of unloading events, by region, were used to construct Tables analogous to Tables S5-3 – S5-7. The calculations lead to an estimated event count of 1,100,000 per year and 11,600,000 for non-plunger wells and plunger wells, respectively, as compared to 177,000 and 6,770,000 estimated based on the survey data collected in this work. A similar calculation could be performed using API/ANGA data averaged on a national, rather than a regional basis, leading to slightly different event counts. Venting events from plunger lift wells based on a national averaging of the API/ANGA survey increase from 11.6 million (regional basis) to approximately 12.6 million events (national basis). Events from non-plunger lift wells decrease from 1.1 million (regional basis) to approximately 0.9 million (national basis). Such estimates would need to be viewed with caution, however. The sub-population on which event counts per well were determined in this work may have different characteristics than the sub-population reported in the API/ANGA survey. An important characteristic of the sub-populations to understand would be the number of wells without plunger lifts that have very high event counts (>50 events/yr). In the survey done in this work, that fraction was low (1.1%). In the API/ANGA data set the fraction is much higher. Overall, the differences between the event counts reported in this work and the event counts in the API/ANGA survey, especially for non-plunger wells, highlight the need for more event count information.

A final sensitivity analysis was performed using GHGRP data for 2013 and revised GHGRP data for 2012, released in October 2014. The major change in these reports, compared to the data used in this work, is the estimated number of plunger lift wells with unloading emissions in Basin 580. Estimating the number of plunger lift wells directly from the GHGRP data requires a number of assumptions to be made concerning wells that use a particular type of reporting (Method 1). Based on assumptions made by the study team, for the revised 2012 report, the estimated plunger lift well count in Basin 580 is 2,187, compared to the plunger lift well count estimate used in this work of 5,041 (Table S5-6). Based on the 2013 reporting year data, released in October 2014, the number of plunger lift wells estimated in Basin 580 rises to 6,433. Applying these well count estimation methods to all of the revised 2012 data and 2013 data results in total unloading emission estimates of 4.6 bcf methane/yr for wells without plunger lifts for both 2013 and revised 2012 data, compared to 4.4 bcf methane/yr reported here. Estimates for plunger lift wells are 7.7 and 10.6 bcf methane/yr for revised 2012 and 2013 data, respectively, compared to 10 bcf reported here.

If the central estimate and range of emission estimates (based on the 95% confidence limits in the measurements used to estimate emission factors) are added to the emission estimates for pneumatic controllers reported by Allen, et al. (2014) and other source categories reported by Allen, et al (2013), total emissions from the natural gas production sector are 2,185 Gg (reported to three significant figures as 2180 Gg), as shown in Table S5-9 and Figure S5-1.

Table S5-9. National emission estimates for the Natural Gas Production sector, based on this work for liquid unloadings, Allen, et al. (2014) for pneumatic controllers, and Allen, et al. (2013) for other sources

Category	Emission Estimates Allen, et al (2014) and 2012 EPA NEI Activity Data Gg methane/yr	2012 National Emission Inventory Estimates Gg methane/yr	Emission Estimates As reported in Allen, et al (2013) Gg methane/yr
Completion flowbacks and workovers from wells with hydraulic fracturing[1]	24[1]	217	18 (5-27)[1] (completions) 143 (workovers)
Chemical Pumps[2]	73[2]	65	68 (35-100)[2]
Equipment leaks [3]	307[3]	191 (est.[4])	291 (186-396)[3]
Pneumatic Controllers	600 (394-1050)	334	580 (518-826)
Unloadings (non plunger lift)	80 (50-160)	155	149
Unloadings (plunger lift)	190 (110-290)	119	108
Other Sources, not measured in Allen, et al., 2013	911	911	891-930
TOTAL methane, Gg	**2185**	**1992**	**2300**

[1]The estimate of 18 Gg for completion flowbacks in Allen, et al. (2013) was based on 8077 well completions, with hydraulic fracturing, in 2011. If this is scaled up to the 10,664 completions and workovers (with hydraulic fracturing) reported in the 2012 NEI, the estimate becomes 24 Gg.
[2]The estimate of 68 Gg for pneumatic pumps in Allen, et al. (2013) was based on a pump count of 35,013 in 2011. If this is scaled up to the pump count of 37,477 reported in the 2012 NEI, the estimate becomes 73 Gg.
[3]The estimate of 291 Gg for equipment leaks in Allen, et al. (2013) was based on a well count of 446,745 in 2011. If this is scaled up to the well count of 470,913 reported in the 2012 NEI, the estimate becomes 307 Gg.
[4]Equipment leak emissions from the source categories measured by Allen, et al. (2013) are not all separately reported in the GHG NEI; estimate based on the mid-point of the range reported by Allen, et al. (2013).

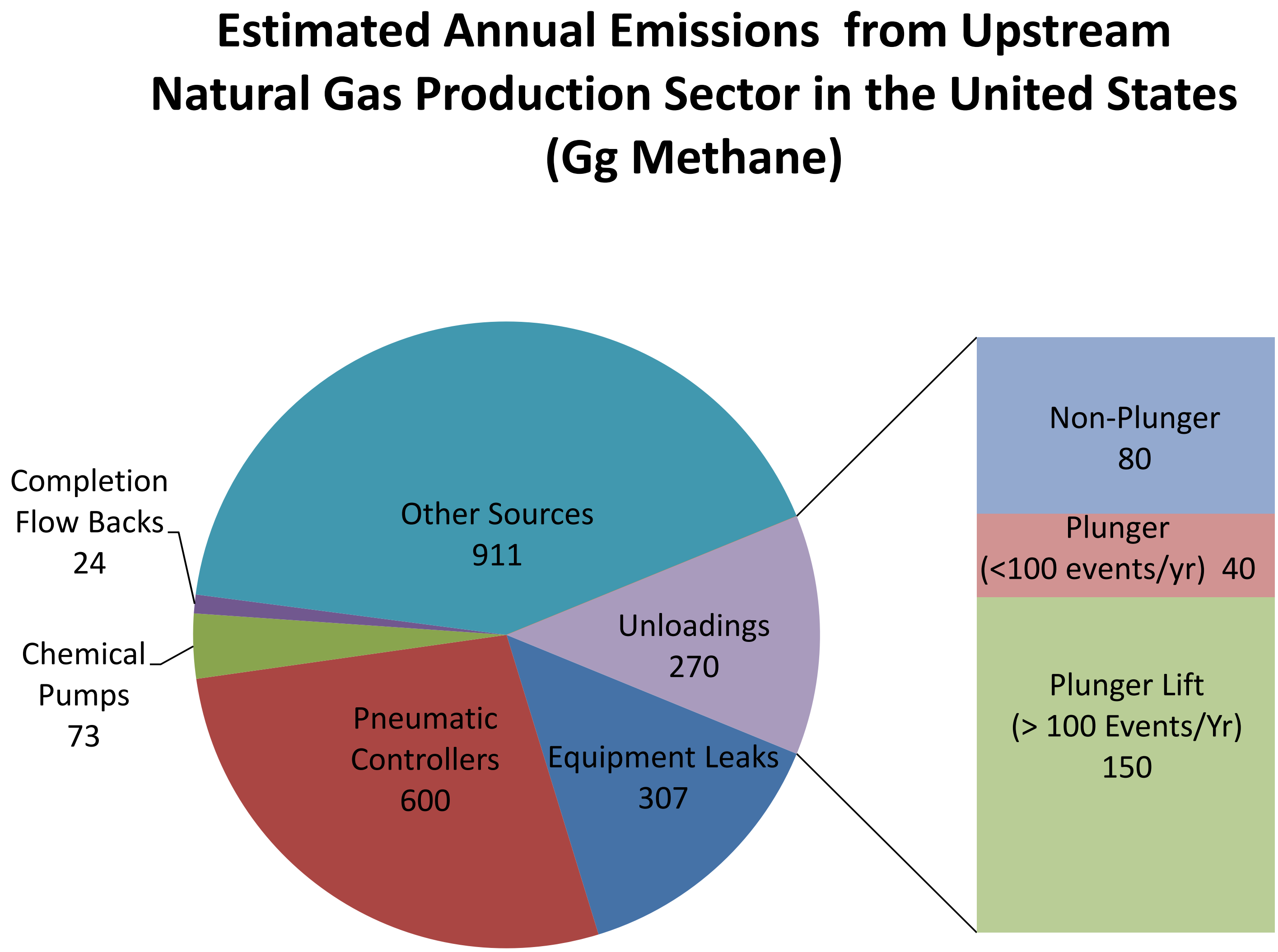


Figure S5-1. Distribution of emissions, by source category in the Natural Gas Production Sector, based on this work.

The total estimated methane emissions from natural gas production (2180 Gg/yr), based on updated estimates for pneumatic controllers and liquid unloadings, is within 10 percent of the emissions estimate in the 2012 GHG NEI (1992 Gg/yr). A larger estimate for pneumatic controller emissions than in the 2012 GHG NEI is balanced by a lower estimate for completion flowback emissions than in the 2012 GHG NEI, resulting in total emissions that are very nearly equal. This result is similar to the comparison reported by Allen, et al. (2013), where total estimated emissions of 2300 Gg/yr was within 10% of the 2011 GHG NEI (as reported in 2013) of 2545 Gg/yr. As in this work, a larger estimate for pneumatic controller emissions than in the 2011 GHG NEI was balanced by a lower estimate for completion flowback emissions than in the 2011 GHG NEI.

The methane emissions reported in Table S5-9 can also be expressed as a percentage of natural gas production. If the 2180 Gg of methane emissions is normalized by total U.S. natural gas gross withdrawals of 29.54 trillion scf (including oil and coal bed, gas, and shale, onshore and offshore) reported by the Energy Information Administration for 2012 (http://www.eia.gov/naturalgas/), methane emissions in the production sector are 0.38% (volume basis) of natural gas gross withdrawals. If it is assumed that the natural gas is 78.8% methane, the methane emissions are 0.48% of methane withdrawals. Allen, et al. (2013) reported these percentages as 0.42% and 0.53% based on 2300 Gg of methane emissions and 2011 natural gas gross withdrawals of 28.5 trillion scf. The differences in percentages between this work and Allen, et al. (2013) are due to both increased withdrawals and decreased emission estimates in the GHG NEI for source categories not measured in this work.

Allen, D.T.; Torres, V.M.; Thomas, J.; Sullivan, D.; Harrison, M.; Hendler, A.; Herndon, S.C.; Kolb, C.E.; Fraser, M.P.; Hill, A.D.; Lamb, B.K.; Miskimins, J.; Sawyer, R.F.; Seinfeld, J.H. Measurements of Methane Emissions at Natural Gas Production Sites in the United States, *Proc. Natl. Acad. Sci. U.S.A.* **2013**, *110*, 17768-17773.

Allen, D.T.; Pacsi, A.; Sullivan, D.; Zavala-Araiza, D.; Harrison, M.; Keen, K.; Fraser, M.; Hill, A.D.; Lamb, B.K.; Sawyer, R.F.; Seinfeld, J.H. Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings, submitted to Environmental Science & Technology (2014).

American Petroleum Institute and America's Natural Gas Alliance (API/ANGA) Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production,: Summary and Analyses of API and ANGA Survey Responses, Final Report, updated September, 2012, available at: http://www.api.org/news-and-media/news/newsitems/2012/oct-2012/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf

S6. Comparison between measurements reported in this work and measurements reported by Allen et al. (11)

Allen et al. [11] reported measurements for 9 unloading events. All were manual unloadings of relatively recent horizontal wells, without plunger lifts, in newly developed shale formations. A comparison of the data reported by Allen et al. and the measurements reported in this work is provided in Table S6-1.

Table S6-1. Comparison of measurements from Allen, et al. [11] and similar measurements made in this work.

	Allen, et al. [11]	Measurements made in this work for horizontal wells without plunger lifts (see horizontal wells in Table S3-3)
Average emissions per event (scf/event)	57,000	52,000
Range of emissions per event (scf/event)	950-191,000	1,400-135,000
Average frequency of unloadings (events/yr)	5.9	40.
Range of frequencies (events/yr)	1-12	1-101
Duration of event (hr)	1.0	2.2
Range of durations (hr)	0.25-2.77	0.35-4.5

The measurements from Allen, et al. [11] were not combined with the measurements in this work for two reasons:

1. Some of the wells on which Allen, et al. [11] made measurements were shut-in for a period of a week or more while the study team made arrangements to get to the site. This shut-in period was not part of routine unloading practices and may introduce a bias into the measurements.
2. If the measurements of Allen, et al. [11] were added to the results from Table S3-3, more than half of the wells with manual unloadings would be horizontal wells. This may not accurately represent national populations.