Brief description of the source

In natural gas production wells, initial gas flow velocity is usually sufficient to entrain produced liquids as droplets and carry them up the well tubing and to a gas/liquid separator. However, as reservoir pressure and flow declines, the gas velocity may be insufficient to lift the produced liquid, leading to liquid accumulation in the well tubing or casing. As liquid accumulates in the gas wells, the head pressure of the liquid becomes greater than the reservoir pressure and eventually slows and stops the flow of gas to the sales line when the combination of sales line pressure and liquid head equal the reservoir shut-in pressure. Hence, these gas wells need to remove or “unload” the accumulated liquids to restore gas production.

Partners can choose from several techniques to remove the liquids or prevent liquid accumulation, including manual unloading, foam agents, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps (ESP), intermittent unloading, gas lift using wellhead compressors. In manual unloading, or “blowing the well,” the operator temporarily closes off the sales line and vents gas from the gas/liquid separator to the atmosphere. This switch relieves the sales line back pressure which allows the reservoir shut-in pressure to push liquids up the well tubing, into the gas/liquid separator, while venting the gas to the atmosphere, resulting in methane emissions. Blowing wells is very inefficient, as low as only 15% of liquids are removed. Some wells are equipped with more efficient plunger lift systems that use pressure build-up in the reservoir and well casing to periodically and efficiently push liquids up the tubing, while still connected to the sales line. After liquids have cleared the tubing, the plunger is dropped back down the tubing. These systems can cycle either automatically connected to the sales line or if there is insufficient reservoir pressure, vent to the atmosphere through the gas/liquid separator, still more efficiently removing liquids than manually blowing the well. In both cases, the liquids go into the separator and/or storage tank, while the gases are transferred to the sales pipeline or vented to the atmosphere.

Other intermediate alternatives to blowing wells include injecting soap through the casing or dropping soap sticks into the well to cause water to foam and be lifted more efficiently or installing a smaller diameter tubing string (aka: velocity tubing) which increases the velocity of gas up the tubing to lift water droplets more efficiently. Velocity tubing also increases tubing string pressure drop and reduces gas production volumes. Operators can also periodically shut a well to build pressure in the reservoir near the well perforations and in the casing, followed by re-opening the well to the sales line to temporarily increase velocity up the tubing and lift liquids.

Eventually reservoir pressure declines to the point where none of these measures sufficiently remove liquids. At this point the liquids can be removed using a down-hole pump, or where there is a wellhead compressor, divert high pressure gas to the well casing to push liquids up the tubing (aka: gas lift).

Annual emissions must be quantified from gas well liquids unloading whenever venting events occur. Examples may include manual liquids unloading (blowing wells to the atmosphere) and plunger lift unloading in which gas is vented to the atmosphere. The volume vented methane varies from one well to another depending on the reservoir properties, well dimensions, type, frequency, and duration of unloading, and methane content of the gas.

Scope boundaries

Methane that is vented to atmosphere during liquids unloading is considered herein. Methane emissions occurring during the transfer process that captured and reintegrated into the process, or sent to alternative units (i.e., not vented), are not to be reported. Methane emissions captured and routed to flare or thermal oxidation should be reported under Flaring (see *Flaring TGD*).

Guidance on materiality is presented in the *General principles TGD.*

Quantification methodology – Level 3

Emission factors

Accepted source-level emission factors, as defined in the *General Principles TGD*, or those prescribed by local regulation are considered as providing Level 3 estimates, provided they are specific for the source type. Partners are encouraged to use emission factors that best represent conditions and practices at their gas wells and adjust the factors, where warranted, to more accurately estimate emissions given differences between the reference system on which the emission factor is based, and their systems.

An emission factor that represents emissions of methane volume per year per well or per event can be applied for liquids unloading, adjusted for operating parameters. Operating parameters include whether the well does or does not have a plunger lift and the frequency of vented events[1]. The following table presents examples of emission factors which can be used to estimate methane emissions from liquids unloading.

Source	Methane Emission Factor		
	(sm^3/yr/event)		(scf/yr/event)
Liquids Unloading Venting – without using plunger lifts[2]	96.3		3,400
Liquids Unloading Venting – using plunger lifts[2]	4.7		166
	sm^3/event	Scf CH4/event	Avg. events/yr
Liquids Unloading without Plunger Lift[3]			
< 10 events per year	609	21,500	2.9
11 – 50 events per year	682	24,100	20.3
50 – 200 events per year	991	35,000	75.6
Liquids Unloading with Plunger Lift[3]			
< 100 events per year	273	9,650	7.7
> 100 events per year	36	1,260	1200

[1] From API, ANGA. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Sept 21, 2012. Retrieved from: http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf.
[2] Average of 2012 and 2013 Method 1 liquids unloading emissions for wells with plunger lift from GHGRP reporting to EPA (data released November 30, 2014)
[3] "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloadings." Dr. Allen, University of Texas, Environmental Science & Technology, December 9, 2014

Quantification methodology – Level 4

Direct measurement and measurement-based emission factors

Measurements (including continuous and periodic monitoring) or emission factors developed based on representative measured emissions are considered Level 4 emissions quantification. Measurements must be taken that represent the total flow and associated methane content of each gas stream that is vented to atmosphere during liquids unloading.

Level 4 emissions quantification can be based on measurements conducted on a representative sample. System configurations and operating conditions (e.g., unloading with or without plunger lifts, number of unloading events per year, duration of unloading events, reservoir properties, methane content of gas) should be considered in determining 'like' systems that carry a common emission factor. Each system that is not 'like' will require determination of a separate emission factor for that system based on the appropriate measurement studies. For guidelines on the methodology to develop a statistically representative sample, please refer to the [*Uncertainty and reconciliation guidance*].

Direct measurement is practical for manual, intermittent, or plunger lift liquids unloading in which venting to the atmosphere occurs from a vent stack (or storage tank with a vent stack)[4,5]. Viewing the vent with an infrared optical gas-imaging camera can also identify emission points that should be measured. After reviewing the site flow configuration and determining the emission location(s), the flow can be measured from the emission point(s). Accepted equipment and techniques, as defined in the *General Principles TGD,* for determining gas flow are to be employed. Following are typical equipment that work well on liquids unloading events, but the list is not exhaustive[4,5]:

- Vane anemometer
- Hotwire anemometer
- Turbine meter

Accepted equipment and techniques, as defined in the General Principles TGD, for determining methane content can be employed.

NOTE: Direct measurement may not be feasible or practical for well swabbing due to the nature of the activities and venting (from the well bore/wellhead). Other liquids unloading (or removal) methods such as surfactants, velocity strings, downhole pumps, and compressors in which gas is not vented do not warrant direct measurement.

[4] More details on various detection and measurement equipment can be found at CCAC, *Conduction Emissions Surveys, Including Emission Detection and Quantification Equipment – Appendix A of the OGMP Technical Guidance Document,* 2017

[5] U.S. EPA. Greenhouse Gas Reporting Program. Subpart W – Petroleum and Natural Gas Systems. Section 98.234: Monitoring and QA/QC requirements, 40 CFR 98.234(b).

Engineering calculations

Accepted engineering calculations that capture all relevant emissions, as defined in the *General Principles TGD*, use measured activity data (i.e. flows and compositions) and consider all major physical and chemical processes relevant to the venting of methane during liquids unloading are considered Level 4 emissions quantification. Measured activity data can be continuous or based on a representative sample. As with direct measurement, engineering calculations may be performed for a representative sample of like systems and then applied to the larger population to quantify methane emissions. For guidelines on the methodology to develop a statistically representative sample, please refer to the [*Uncertainty and reconciliation guidance*].

Following are examples of engineering calculations which can be used to quantify methane emissions from liquids unloading events, but the list is not exhaustive.

Wells without plunger lift systems[6]

$$\boldsymbol{E = V * \left((0.37\,X\,10^{-3}) * CD^2 * WD * SP\right) + \sum_{q=1}^{V}\left(SFR * \left(HR_q - 1.0\right) * Z_q\right)}$$

E = Annual natural gas emissions at standard conditions, in cubic feet per year (scf).

V = Total number of unloading events per year per well.

$0.37\,X\,10^{-3} = \frac{3.14\,(pi)}{4}/(14.7 \,*\, 144)$

(pounds per square inch absolute (psia) converted to pounds per square feet).

CD = Casing internal diameter for each well in inches.

WD = Well depth (top of the well or the lowest packer to the bottom of the well), for each well in feet (ft).

SP = Shut-in pressure or surface pressure for wells with tubing production or casing pressure with no packers, in psia; If casing pressure is not available, Partners can multiply the tubing pressure of each well with a casing-to-tubing pressure ratio of a well with no packer from the same sub-basin, in psia.

SFR = Average flow-line rate of gas for well at standard conditions, in cubic feet per hour (scf).

HR_q = Hours that the well was left open to the atmosphere during each unloading event, q (hr).

1.0 = Hours for average well to blowdown casing volume at shut-in pressure (hr).

Z_q = If HRq < 1.0, then Zq is equal to 0. If HRq is >= 1.0, then Zq is equal to 1.

Plunger Lift Unloading Calculation[6]:

$$\boldsymbol{E_S = \sum_{p=1}^{W}[V_p * ((0.37X10^{-3}) * TD_p^2 * WD_p * SP_p + \sum_{q=1}^{V_p}(SFR_p * \left(HR_{p.q} - 0.5\right) * Z_{p.q}}$$

E_s = Annual natural gas emissions for each sub-basin at standard conditions, in standard cubic feet (scf).

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period for each well, p.

TD_p = Tubing internal diameter for each well, p, in inches.

WD_p = Tubing depth to plunger bumper for each well, p, in feet (ft).

SP_p = Flow-line pressure for each well, p, in psia, using engineering estimates from best available data.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour (scf/h).

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

q = Unloading event.

Zp,q = If HRp,q < 0.5 then Zp,q is equal to 0. If HRp,q is >= 0.5 then Zp,q is equal to 1.

[6] U.S. EPA. Greenhouse Gas Reporting Program. Subpart W – Petroleum and Natural Gas Systems. Section 98.233: Calculating GHG Emissions. 40 CFR 98.233(f)(1).