Brief description of source

Unstabilized liquids storage tanks in the onshore oil and natural gas sector are used to hold a variety of liquids, including crude oil, gas condensates, and produced water. They may be stored in fixed-roof atmospheric pressure tanks or floating-roof tanks between production wells and pipeline, rail, or truck transportation. Offshore production fluids may be stored in a floating production storage and off-taking (FPSO) vessel prior to transfer to an oil tanker.

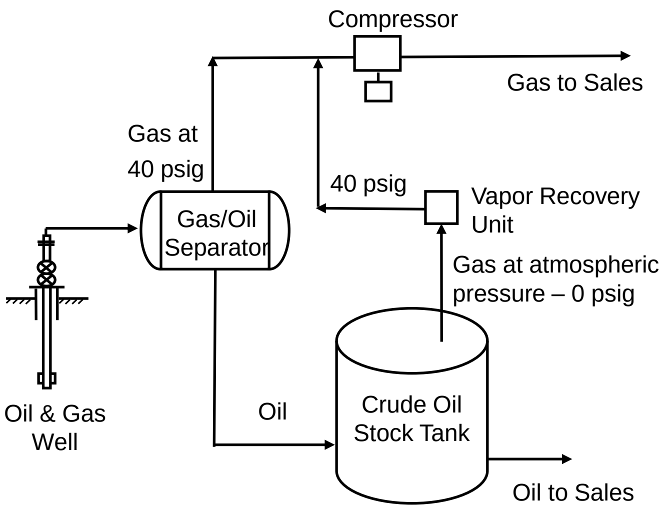
Onshore, a gas/liquid separator vessel receives unstabilized liquids and operates at a pressure high enough to provide sufficient suction pressure to a wellhead compressor, or to enter a gas gathering pipeline, and to push the liquids into a full storage tank, typically 35 to 50 psig (2.4 to 3.4 bar). Methane, volatile organic compounds (VOCs), hazardous air pollutants (HAPs), and some other gases (hydrogen sulfide, carbon dioxide, nitrogen, oxygen) flash (vaporize) from the liquid entering the tank and accumulate in the vapor space between the liquid surface, the walls and roof of the tank. Fixed roof tanks or floating-roof tanks cannot contain any significant pressure above atmospheric pressure, and therefore these vapors are vented, flared, or sent to a vapor recovery unit (VRU).

Emissions from storage vessels are a combination of flash, working, and standing losses. Flash losses (the most significant) occurs when a pressurized liquid with dissolved gases is transferred from the higher-pressure gas/liquid separator to an atmospheric pressure storage tank. Working losses occur when vapors above the liquid surface are pushed out by rising liquid levels and agitation of liquids in tanks. Standing losses occur when vapors expand and vent due to the daily and seasonal temperature and barometric pressure changes. Pressure can also increase during normal separator dump events. The oil and gas separators connected to the storage tanks have a liquid level control valve (sometimes called a “dump valve”) to control release of pressurized liquid to the storage tank.

Most commonly, tank vapors are vented to the atmosphere through a pressure/vacuum relief valve protecting the tank’s integrity or through other openings in the tank. The gas can also be re-routed to a Vapor Recovery Unit (VRU) for productive use or routed to a combustive flare. However, emissions from storage tanks are not limited to the vent and can come from defects in the tanks, including but not limited to, visible cracks, holes, gaps in piping, loose connections, broken or missing caps, a leaking pressure/vacuum safety valve, loose or open thief hatch, or other closure devices.

The volume of vapor emitted from a storage tank or FPSO is dependent on factors such as tank roof configuration, tank capacity, operating throughput, pressure in the gas/liquid separator and oil or condensate flow rate from the separator into the tank. The greater the differential in pressure between the separator and the tank, the higher the flashing losses. Lighter crude oils (API gravity >36°) flash more hydrocarbon vapors than heavier crudes (API gravity <36°). Additionally, in storage tanks where oil cycling is frequent and overall throughput is high, more working losses will occur than in tanks with low throughput and where oil is held for longer periods of time. The composition of tank vapors varies based on the type of production and the hydrocarbons being produced.

Figure 1 - Example of crude oil storage tank configuration



System boundaries

Vapors vented or leaked into the atmosphere from onshore unstabilized liquids storage tanks and FPSOs are considered herein. Emissions from storage tanks that are captured and reintegrated into the process (VRU), i.e. not vented, are not to be reported. Methane emissions captured and routed to a flare or to thermal oxidizer should be reported under Flaring (see *Incomplete combustion from gas flaring TGD*). Remaining emissions related to capture of emissions from tanks, are to be considered herein. Unintended methane emissions not associated with unstabilized liquids flashing, working and standing losses that may enter and vent from tanks should be reported under incidents or malfunctions (see *Incidents and malfunctions TGD*). Partners should identify this malfunctioning sources during tank inspection. Stuck separator dump valves, are not part of typical operations and can, therefore, be reported under the *Incidents and malfunctions TGD.*

This TGD covers emissions from unstabilized liquids storage tanks (crude oil, condensate, produced water) and, as such, does not cover emissions from diesel, gasoline, naphtha or LNG storage tanks.

Emissions associated with liquids transfer from tanks and emissions from transfer connection points, should be reported under the *Venting and purging TGD*.

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

Level 3 Quantification Methodologies

Emission Factors

Accepted 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 should apply an emission factor that represents emissions of methane volume per year per storage tank, adjusted for the actual operating factor of the tanks. Partners are encouraged to use emission factors that best represent conditions and practices at their facilities. The following table presents examples of emission factors which can be used to estimate methane emissions from atmospheric storage tanks.

Source	Methane Emission factor	Unit	Methane emission factor	Unit

Crude oil: large tanks (≥10 bbl crude/day - >1.6 scm/day), small tanks (<10 bbl crude/day - <1.6 scm/day) [1]				
Large Tanks w/Flares	0.00525	Kg CH_4 / bbl throughput	0.033	Kg CH_4 / scm throughput
Large Tanks w/VRU	0.0283	Kg CH_4 / bbl throughput	0.178	Kg CH_4 / scm throughput
Large Tanks w/o Control	0.193	Kg CH_4 / bbl throughput	1.215	Kg CH_4 / scm throughput
Small Tanks w/Flares	0.00206	Kg CH_4 / bbl throughput	0.013	Kg CH_4 / scm throughput
Small Tanks w/o Flares	0.0184	Kg CH_4 / bbl throughput	0.116	Kg CH_4 / scm throughput
Average value w/o control	0.886	Kg CH_4 / bbl throughput	5.576	Kg CH_4 / scm throughput
Condensate: large tanks (≥10 bbl condensate/day- >1.6 scm/day), small tanks (<10 bbl condensate/day- >1.6 scm/day) [2]				
Large Tanks w/Flares	0.00579	Kg CH_4 / bbl throughput	0.036	Kg CH_4 / scm throughput
Large Tanks w/VRU	0.00665	Kg CH4 / bbl throughput	0.042	Kg CH_4 / scm throughput
Large Tanks w/o Control	0.146	Kg CH_4 / bbl throughput	0.919	Kg CH_4 / scm throughput
Small Tanks w/Flares	0.00091	Kg CH_4 / bbl throughput	0.006	Kg CH_4 / scm throughput
Small Tanks w/o Flares	0.119	Kg CH_4 / bbl throughput	0.749	Kg CH_4 / scm throughput
Average value w/o control	2.3	Kg CH_4 / bbl throughput	14.474	Kg CH_4 / scm throughput
Produced water[3]				
Separator pressure 50 psi (3.4 bar) Produced water salt content 20%	0.0015	t CH_4 / 1000 bbl produced water	0.009	t CH_4 / 1000 scm produced water
Separator pressure 250 psi (17.2 bar) Produced water salt content 10.7% (average)	0.0142	t CH_4 / 1000 bbl produced water	0.089	t CH_4 / 1000 scm produced water
Separator pressure 1000 psi (68.9 bar) Produced water salt content 10.7% (average)	0.0508	t CH_4 / 1000 bbl produced water	0.32	t CH_4 / 1000 scm produced water

[1] API Compendium, 2021, Table 6-22
[2] API Compendium, 2021, Table 6-24
[3] API Compendium 2021, Table 6-26

Activity data collection should be conducted based on the data required by the selected emission factor. In the example presented above, data on annual tank throughput would be required.

Lab Analysis

An alternative for estimating emissions from storage tanks is to obtain a pressure bomb sample of the oil in the separator and perform a lab analysis to determine how much methane will be vented from this sample as the pressure drops to tank pressure (atmospheric). Apply this ratio to the volume of oil removed from the tank, and the subsequent volume of emissions can be assumed to be the vented volume. Nearly all methane will flash out of the oil at atmospheric pressure. This method is relatively easy to implement but does not accurately characterize total gas emissions. Used in combination with engineering calculations, it can provide a more accurate estimation of the emissions.

Engineering calculations

Simple engineering calculations or empirical equations can be used to quantify methane emissions from unstabilized liquids storage tanks at level 3. Partners can calculate flashing emissions from liquids transferred to storage tanks with empirical equations such as Vasquez-Beggs[4] or the Griswold and Ambler GOR Chart[5] methods.

Level 4 Quantification Methodologies

Direct measurement and Measurement-based Emission factor

Measurements (including continuous and periodic monitoring) or emission factors developed based on representative measured emissions are considered Level 4 emissions quantification. Direct measurement in conjunction with vent gas composition analysis is an accurate method for quantifying methane emissions from flashing losses. However, standing and working losses are less accurately quantified by direct measurement and with changes in crude oil composition from multiple wells. With direct measurement, and through taking steps to stop potential gas bypass and accounting for working losses, it helps reduce the level of uncertainty.

The first step for direct measurement is identifying the emission point(s). Observing the tank roof and tank vent with an infrared (IR) optical gas imaging camera (designed to visually identify hydrocarbon emissions) both before and during measurement will show locations from which gas is vented. A measurement is commonly taken directly from the vent of a storage tank using a flow totalizing turbine meter or electronic packing vent (ePV™) meter. Partners can also route the flow from an open thief hatch to a measurement device. Measurements should also be conducted in different operating conditions, to the extent that those can affect emissions levels.

Other 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 hydrocarbon storage tanks, allow to quantify emissions over a period of time and can be connected to a data recording or logging system, but the list is not exhaustive[6] [7]:

- Turbine meter.
- ePV electronic packing vent monitor

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[4] API Compendium 2021, Section 6.3.9.1 *Flashing losses from unstabilized crude and condensate storage tanks*
[5] API Compendium 2021, Section 6.3.9.1 *Flashing losses from unstabilized crude and condensate storage tanks*
[6] 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
[7] More details on various detection and measurement equipment can be found at Marcogaz, *Assessment of methane emissions for gas Transmission and Distribution system operators,* 2019 – Section 7 (p. 34-39)

- Ultrasonic flow meter
- Hotwire anemometer

Measurements should be conducted over a long enough period to account for variability in flow during multiple tank filling and pump-out cycles (e.g., 24 to 48 hours). The annual volume of methane emitted can be calculated by taking the measured total methane emissions flow rate divided by total oil input to develop a factor of methane emissions per barrel of oil throughput and multiplying this ratio by the annual throughput of the storage tank(s). This factor can be used to calibrate an equilibrium model that can be applied to all tanks in like service.

Level 4 emission factors should be based on measurements conducted on a representative sample. System configurations, environmental and operating conditions (e.g. type of hydrocarbon stored, seasonal atmospheric variations, throughput rate) should be considered in determining 'like' systems that carry a common emission factor. Each system that is not 'like' will require the 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*].

Emission factors expressed in terms of emission per unit of vented throughput will allow for easy adjustment of activity data (i.e. flow and composition data).

Process simulation and detailed engineering calculations

Process simulation and detailed engineering calculations, in combination with sampling and lab analyses of the composition of the liquid held in the storage tank, is considered as a Level 4 quantification methodology.

Partners can calculate flashing, working, and standing emissions from liquids transferred to storage tanks with equation of state programs, such as AspenTech HYSYS®[8], Honeywell Process UniSim[9], TankESP[10] or E&P TANKS5[11], or empirical equations. Typically, at a minimum, the following parameters are necessary for using the computer programs or charts: (1) gas/oil separator pressure and temperature, (2) sales oil or stabilized oil American Petroleum Institute (API) gravity, (3) sales oil or stabilized oil production rate, (4) ambient air pressure and temperature, and (5) gas/oil separator oil composition and Reid vapor pressure. Using software analysis and engineering calculations in combination can lead to a more accurate estimation of the emissions.

NOTE: if separator oil composition and Reid vapor pressure data are not available, default values from the E&P TANKS program that most closely match separator pressure can be used, or API gravity as a second option.

[8] https://www.aspentech.com/en/products/engineering/aspen-hysys
[9] https://www.honeywellprocess.com/en-US/explore/products/advanced-applications/unisim/Pages/default.aspx
[10] https://www.trinityconsultants.com/software/tanks/tankesp
[11] https://www.eptanks.com/