SG.17.1.7

TECHNICAL GUIDANCE DOCUMENT NUMBER 7:

WELL VENTING FOR LIQUIDS UNLOADING

Introduction

This document provides technical guidance to Partners of the CCAC Oil and Gas Methane Partnership (OGMP). It is one in a series describing a core source of methane emissions from oil and natural gas production operations. The guidance documents introduce suggested methodologies for quantifying methane emissions from specific sources and describes established mitigation options that Partners should reference when determining if the source is "mitigated."[1] The OGMP recognizes that the equipment and processes described in these documents are found in a variety of oil and gas operations, including onshore, offshore, and remote operations, and the way in which the emissions are quantified and mitigated may vary across locations and operational environments. As such, operational conditions, as well as logistical, safety and cost considerations, must be evaluated on a case-by-case basis. The OGMP assumes that methane emission mitigation actions that require shut-downs of non-redundant equipment/processes (e.g., that would result in a stoppage of operations) would be carried out during regularly scheduled maintenance activities, unless the Partner deems the corrective action to be worthy of an early/additional shut-down.

Description of Source

Over time, gas production naturally declines in non-associated gas wells as the reservoir is depleted. Initial flow (gas velocity) from a gas well is usually sufficient to entrain produced liquids as droplets and carry them through the wellhead and to a separator. However, as flow declines, the gas velocity may be insufficient to lift the produced liquid, and liquid may accumulate in the wellbore. As liquid accumulates in non-associated gas wells, the pressure of the liquid becomes greater than the gas velocity and eventually slows or stops the flow of gas to the sales line. These gas wells therefore often need to remove or "unload" the accumulated liquids so that gas production is not inhibited. Well liquids must be managed on an ongoing basis and adapted to the changes in wells' flow characteristics as wells move through their lifecycle.

Four main flow regimes normally occur in a gas well: mist flow, annular flow, slug flow, and bubble flow. Mist flow, where the gas flows and carries the liquids in mist form, is ideal. Annular flow is slower than mist flow. In annular flow, the lighter gas travels up the center of the well tubing and the heavier liquids flow along the walls of the tubing. At still slower velocities, called slug flow, liquids separated by pockets of gas flow up the tubing. Finally, at even slower velocities, the gas flows according to what is known as bubble flow. In bubble flow, the gas is dispersed in the liquid phase and flows at a very slow rate. In this phase, the gas is no longer carrying the liquids through the tubing, resulting in accumulation of the liquids.[2]

[1] For reporting purposes as described in the CCAC Oil and Gas Methane Partnership Framework, Section 3.
[2] Guo, Boyun; Ghalambor, Ali; Natural Gas Engineering Handbook, pgs. 241–254.

Because fluids slow the gas velocity, their build-up needs to be addressed. Partners can choose from several techniques to remove the liquids, including manual unloading, foam agents, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps (ESP), intermittent unloading, gas lift, and wellhead compression, as liquids unloading practices. Each method removes accumulated liquids and thereby maintains or restores gas production. Below is a summary of these methods:

- "*Manual Liquids Unloading with Atmospheric Venting*"- The well is choked with liquids built up in the tubing, substantially reducing or stopping gas production to the sales line. At that time, the sales line connection is manually shut-off, and well production is routed to an atmospheric tank with lower back-pressure than the production system. This allows reservoir (gas) pressure to lift the liquid from the well. The entrained gas is vented to the atmosphere at the tank. Subsequently the well is manually rerouted to the production system and sales gas line. In some cases, the well is shut-in for a period of time to build-up pressure before being routed to an atmospheric tank.

- *"Manual Liquids Unloading without Atmospheric Venting"*- The well is shut-in before liquids choke off gas flow, allowing the reservoir pressure to rise to shut-in pressure. The well is re-opened and flow routed to the separator with gas going to sales and liquids to storage.

- "*Automated Liquids Unloading*"- Similar to manual unloading without atmospheric venting, except a timing and/or pressure device is used to optimize intermittent shut in of the well before liquids choke off gas flow. The reservoir pressure rises sufficiently to lift liquids to the separator (gas to sales without atmospheric venting) or direct liquids to an atmospheric storage tank (substantially less entrained gas vented to the atmosphere).

- "*Foaming Agents*"- Chemicals are added to the well that reduce the liquid density through foaming, which improve the ability of the gas to carry the liquids to the surface.

- "*Velocity Tubing or Strings*"- Installation of several smaller sized tubing strings in place of the single larger production tubing increases gas flow velocity in each small tube, thus allowing the well's gas flow to carry the liquids out.

- *"Plunger Lift System"*- A mechanical system with an automated controller that can close in the well, allowing the plunger to drop to the bottom of the well. The controller then reopens the well, allowing the gas to push the plunger to the top with a slug of liquid on top. The controller can be activated manually, by a mechanical timer, by a pressure controllers, or with an automated "smart" cycle system. Depending on the plunger system design and operation, plunger controllers may be designed to allow automatic venting if the plunger does not return when expected, thus creating an emission during ***some*** plunger trips. Other systems are designed to vent on every plunger lift trip.

- "*Sucker Rod or Beam Pumps*"- Installation of a rod pump system to lift liquids up the tubing through a series of check valves. Flow is routed to the separator with gas going to sales and liquids to the storage tank. This technology requires electric power at the well site.

- "*Electric Submersible Pump*"- Installation of an electric submersible pump to pump liquids through the well. Flow is routed to the separator with gas going to sales and liquids to the storage tank. This technology requires electric power at the well site.

- *"Jet Pumps"*- Installation of pumps that use a power liquid to transfer energy from surface pumps into reservoir fluids. Flow is routed to the separator with gas going to sales and liquids to the storage tank.

- *"Progressive Cavity Pumps"*- Installation of low-speed, downhole rotary positive displacement pumps typically driven by a rod string attached to an electric or hydraulic motor on the surface. Flow is routed to the separator with gas going to sales and liquids to the storage tank. This technology may require electric power at the wellhead.

- *"Gas Lift"*- A compressor pushes high-pressure gas downhole in order to increase total gas velocity up the well. Flow is routed to the separator with gas going to sales and liquids to the storage tank.

- *"Wellhead Compressor"*- A compressor pulls gas from the wellhead in order to reduce gas flow operating pressure from the well, which reduces gas flow pressure at well "bottom hole," which increases well bore (gas flow) velocity. Flow is routed to the separator with gas going to sales and liquids to the storage tank.

Systems for unloading well liquids can be configured in a variety of ways. Partners should identify the configuration for each well. Some options include those listed in the following table.

Table 7.1: Configurations for Well Liquids Unloading

Configuration	Mitigated or Unmitigated
Manual liquids unloading is conducted with atmospheric venting (e.g., separator is bypassed and gas vented from atmospheric tank). Exhibit A	Unmitigated
Manual liquids unloading is conducted without atmospheric venting (gas from separator going to sales).	Mitigated
Automated liquids unloading is conducted with atmospheric venting but operator has optimized the intermittent venting such that the vented emissions are substantially less than manual liquids unloading venting.	Mitigated
Automated liquids unloading is conducted without atmospheric venting.	Mitigated
Foaming agents, soap strings, and surfactants (Option A); and velocity tubing/strings (Option B) are used to abate or substantially minimize manual liquid unloading events.	Mitigated
Plunger lift is used for liquids unloading without atmospheric venting (gas going to sales and liquids to storage) (Option C). Exhibit B	Mitigated
Plunger lift is used for liquids unloading with routine atmospheric venting occurs (e.g., separator is bypassed) but	Mitigated

operator has optimized the plunger lift operations such that vented emissions are substantially less than manual liquids unloading venting (Option C). Exhibit B	
Pumps (e.g., electric submersible pump, jet pump, progressive cavity pumps) are used to removed liquids from the well and abate or negate the need for manual unloading (Option D). Exhibit C	Mitigated
Gas lift or wellsite compressor is used to remove or reduce liquids in the well (and hence abate the need for manual unloading) (Option D).	Mitigated

Configurations that are not identified above as "mitigated" for methane emissions should be quantified and evaluated for mitigation, as described in the sections below. Even in the mitigated situations described above, operators should evaluate the system to ensure that it is not malfunctioning, which could result in higher methane emission levels.

Quantification Methodology

One or more of the following methodologies should be used to quantify annual emissions that result from gas well liquids unloading in which venting during the unloading event occurs. Examples may include manual liquids unloading, intermittent unloading or plunger lift unloading in which gas is vented to the atmosphere. In principle, direct measurement can be considered as the most accurate method for quantifying methane emissions.[3] Where a sound basis is in place, measurement can contribute to greater certainty on emissions levels and economic costs and benefits (i.e., value of gas saved). As such, measurement is highly encouraged whenever possible to establish this basis.

The OGMP recommends partner companies to use one of the following methodologies to assure the consistent quantification of emissions and the comparable evaluation of mitigation options. These quantification methodologies include: direct measurement, engineering calculation, or emission factor approach. Individual Partners may choose an alternative quantification methodology if judged to be more accurate by the Partner; in this case, the Partner should document and explain the alternative methodology in the Annual Report.

[3] Partners should conduct measurements with appropriately calibrated instruments and per the instrument manufacturer instructions. Measurements should also be conducted in different operating conditions, to the extent that those can affect emissions levels. Appendix A to the Technical Guidance Documents includes guidance on instrument use. Partners seeking to generate Emission Factors for their operations should use direct measurement based on a statistically sound number of measurements and gas analyses to understand the content of methane and other valuable hydrocarbons.

- Direct Measurement:[4] Direct measurement may be feasible or practical for manual, intermittent, or plunger lift liquids unloading in which venting to the atmosphere occurs from a vent or storage tank.[5]

For manual, intermittent, or plunger lift wells that require venting during liquids unloading's, the well's flow during an unloading event is routed to an atmospheric production tank, where the tank acts as a separator to collect liquids, and the gas flow is released through the top of the tank, typically through an open thief hatch or other openings in the tank's fixed roof. The thief hatch is typically manually opened just for the duration of the unloading operation. However, each facility setup is unique, and some sites have dedicated open top tanks or other openings in the tank. It may be necessary for Partners to review the site flow during unloading activities. Viewing the vent with an infrared leak-imaging camera can also identify emission points that should be measured. After reviewing the site flow configuration and determining the emission location(s), then Partners can directly measure the flow from the emission point(s) with a **temporary flow meter stack** or can insert a flow meter upstream of the emission point within the process piping using a generally accepted meter, such as:

- Vane anemometer
- Hotwire anemometer
- Turbine meter

The measured flow rate then is used in the following equation to obtain the annual emissions. The whole gas emissions can then be multiplied by the methane composition to calculate the annual methane emissions.

$$E_a = F_p FR$$

Where:

E_a = Annual whole gas emissions at standard conditions in cubic feet (scf).
F_p = Frequency of the venting events (number of occurrences per year).
FR = Cumulative whole gas flow rate in cubic feet at standard conditions over the duration of the liquids unloading event (scf).

Note that the frequency of events, Fp, can be gathered from a number of approaches. In cases of manual venting, this will require data gathering from a log of manually initiated events. In the case of automated venting of plunger lift systems, this frequency can likely be collected directly from the plunger controller, which logs the number of events where the plunger did not return in the expected period and when the controller vented the well as a result.

- Engineering Calculation: If the direct measurement approach is not selected or is not feasible or practical, an engineering calculation approach can be used. The calculation methodology

[4] 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). http://www.ecfr.gov/cgi-bin/text-idx?SID=0be28a76d43cbee6ce31f26e5a2bc9c0&node=40:22.0.1.1.3.23&rgn=div6.

[5] 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.

for emissions from wells without plunger lifts (e.g., manual or intermittent unloading) and wells with plunger lifts are provided below.[6]

Manual or Intermittent Unloading Calculation:[7]

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

Where:

E = Annual natural gas emissions at standard conditions, in cubic feet per year (scf).
V = Total number of unloading events per year per well.
0.37×10^{-3} = {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 from either the 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 = If HR_q is less than 1.0, then Z_q is equal to 0. If HR_q is greater than or equal to 1.0, then Z_q is equal to 1.

Plunger Lift Unloading Calculation:[7]

$$E_s = \sum_{p=1}^{W} \left[V_p \times \left(\left(0.37 \times 10^{-3}\right) \times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p} \left(SFR_p \times \left(HR_{p,q} - 0.5\right) \times Z_{p,q}\right) \right]$$

Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, 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.
0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
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 based on best available data.

[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). http://www.ecfr.gov/cgi-bin/text-idx?SID=ba51a263399deb7722bbf4375da8d43f&mc=true&node=se40.23.98_1233&rgn=div8.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour (scf/h). Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = 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.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

Emission Factors:[7] If the direct measurement approach is not selected or is not feasible nor practical, an emission factor approach can be used as an option to engineering equations. An emission factor that represents emissions of methane volume per year per well or per event should 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. Partners are encouraged to use emission factors that best represent conditions and practices at their facilities. Default methane emission factors are provided in Tables 7.2-7.4[8].

Mitigation Methodologies

The following are example mitigation methodologies that may reduce emissions associated with well liquids unloading. Note that each of these mitigation strategies is not universally applicable and will only apply to wells operating under certain conditions, as described in the following sections.

Mitigation Option A – Foaming Agents, Soap Strings, Surfactants

Foaming agents, soap strings and surfactants reduce the density and surface tension of the liquids in the well, thereby reducing the velocity needed for the gas to carry the liquids out of the well. The surfactants are added either as a soap stick or through liquid injection. If the well is deep, injection requires a pump that can be electric, pneumatic, or mechanical.

Operational Considerations

Foam produced by surfactants works best in wells where the liquids comprise 50 percent or more water. The surfactants are not effective when mixed with hydrocarbons, so they should only be selected when producing significant water. Foaming agents generally work best where the rate of liquid accumulation is low.

Surfactants can be delivered to the well as soap sticks or as a liquid directly injected into the casing-tubing annulus. In a shallow well, the surfactant can be delivered by pouring it down the annulus of the well through an open valve. In a deep well, a surfactant injection system will be required (along with regular monitoring). The surfactant injection system includes a surfactant reservoir, a motor valve (usually with a timer, depending on the system design), an injection pump, and a power source

[7] 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.

[8] "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.

for the pump. Typically, no equipment is required in the well. Options for pumps include electric, mechanical, and pneumatic. Various pump types have different advantages regarding reliability, precision, efficiency, and maintenance frequency.

If Partners plan to install a surfactant injection system, implementing this technology requires the installation of the following equipment:

- A surfactant reservoir.
- A motor valve (usually with a timer, depending on the system design).
- An injection pump (electric, mechanical, or pneumatic).
- A power source for the pump.

Methane Emission Reduction Estimate

According to Natural Gas STAR's Lessons Learned, the foaming agent saves 178 to 7,394 thousand cubic feet (Mcf) per well per year (5 to 209 thousand cubic meters (Mcm) per well per year) compared to swabbing and blowing down a well.[9]

Economic Considerations

The cost for using a foaming agent depends on whether a pump is necessary. The pump cost can range from $500 to $9,900, and the surfactants cost $500 per month.[10] The economics of foaming agents include the upfront capital cost of the surfactants and potentially a pump, the volume of gas savings if the previous practice was blowing down the well, and the revenue from increased production. Based on partner Natural Gas STAR companies, the increased production using foaming agents ranged from 360 to 1,100 Mcf (10 to 31 Mcm) per well per year.[11] Many other additional costs should be considered, including elimination of well swabbing and electricity.

Mitigation Option B – Velocity Tubing/Strings

The velocity of the gas being produced is a function of the pressure drop and the cross-sectional area of the production tubing. Therefore, one option is to install velocity tubing. Velocity tubing effectively reduces the cross-sectional area of the well, thereby increasing the velocity.

Operational Considerations

Velocity tubing requires relatively low liquid production and a higher reservoir pressure to create the necessary pressure drop. As a rule of thumb, velocity tubing can be effective with velocities above 1,000 feet/minute (ft/min) (305 meters/minute, m/min). As the velocity falls below 1,000 ft/min (305 m/min), such tubing is no longer effective. An Inflow Performance Relationship curve should be used to assess the flow of the well. Foaming agents can be used in conjunction with velocity tubing to extend the effectiveness of velocity tubing at lower velocities.

Wells that are marginal producers are candidates for velocity tubing. Marginal wells are defined as "a producing well that requires a higher price per Mcf or per barrel of oil to be worth producing, due to low production rates and/or high production costs from its location (e.g., far offshore; in deep waters;

[9] EPA. Lessons Learned: *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf.

[10] Ibid.

[11] Ibid.

onshore far from good roads for oil pickup and no pipeline) and/or has high co-production of substances that must be separated out and disposed of (e.g., saline water, non-burnable gases mixed with natural gas)."[12]

Implementing this technology requires the installation of:

- Tubing connections

Methane Emission Reduction Estimate

According to Natural Gas STAR's Lessons Learned, velocity tubing saves 150 to 7,400 Mcf per well per year compared to swabbing and blowing down a well.

Economic Considerations

The cost for implementing velocity tubing can range from $7,000 to $64,000 per well. This cost includes the workover rig time, downhole tools, tubing connections, and labor. The economics of velocity tubing include the upfront capital cost, the volume of gas savings if the previous practice was blowing down the well, and the revenue from increased production. According to partner companies in Natural Gas STAR, velocity tubing increases production between 9,125 and 18,250 Mcf/well per year (258 and 517 Mcm/well per year). Other additional costs that should be considered include elimination of well swabbing.

Mitigation Option C – Plunger Lift

A plunger lift system uses the energy of the gas pressure build-up in the casing and reservoir to push a plunger up the well. The plunger acts like a piston to remove undesired liquids from the well. A plunger lift system comprises a lubricator and holding component, a bumper spring at the bottom of the well, and the plunger. This system is used as the velocity decreases, indicated by a change in pressure of the casing. Because the pressure drops as the liquid level increases, the plunger lift is used when the pressure in the casing reaches a predetermined level. The plunger lift can be operated manually, with a mechanical timer, pressure controllers or with an automated "smart" cycle timer system. The gas line is closed off, the plunger drops, the well is shut to allow pressure to build up behind the plunger in the casing, and the well is then opened to the sales line lifting the plunger with the liquids out of the well.

Plunger systems are not always a mitigation technology, since plunger systems can be vented frequently enough to produce higher net emissions than from less frequent manual unloading. Per the above, plunger lifts can be considered mitigation technologies when they are optimized to achieve minimal gas venting.

Operational Considerations

A few conditions must be met before a plunger lift system can be justified. First, fluid removal needs to be necessary to maintain production. As stated previously, this situation is more common in mature wells because of the liquid build-up that occurs over time. Additionally, for the plunger to have the required force, wells must produce 400 scf (11 scm) of gas per barrel of fluid per 1,000 feet (305

[12] Interstate Oil & Gas Compact Commission (2010). Marginal Wells: Fuel for Economic Growth.

meters) of well depth. The shut-in wellhead pressure also needs to be at least 1.5 times the sales line pressure. Wells that have scale or paraffin build-up also are candidates for plunger lifts.

Implementing this technology requires the installation of the following equipment:

- Lubricator
- Plunger catcher and bumper
- Plunger

Methane Emission Reduction Estimate

Example: A well blowdown is estimated to emit 2,000 scf (57 scm) per hour. With a blowdown occurring once every month, the potential reduction is 24 Mscf (0.7 Mscm) per year, assuming 1 hour per blowdown. Overall methane emissions reductions would be the eliminated blowdown emissions minus the estimated venting from a plunger lift operation.

Economic Considerations

EPA's Natural Gas STAR technical document for installing plunger lifts on wells[13] indicates the cost for implementing a plunger lift is estimated to be $1,900 to $7,800 with a maintenance cost of $1,300 per year. The economics of a plunger lift include the upfront capital cost, the maintenance costs, the reduced emissions volume compared to the previous operational practices, and the revenue from increased production. In one example, according to Natural Gas STAR partner company data from 14 sites in Midland Farm Field, Texas, production increased by 91 Mcf/day (2.6 Mcm/day) 30 days after implementing the plunger lift. Depending on the method in place for removing the liquids before a plunger lift, many other additional costs should be considered, including the well treatment costs, electricity savings, and workover costs savings and the salvage value of any previous technology such as a beam lift. The plunger lift has no well treatment costs, has reduced electricity costs, and has reduced workover costs compared to a beam lift. Based on a Natural Gas STAR Partner's experience, installing a plunger lift could have a payback in less than two months and yield excellent gas savings as well as increased gas production.

Mitigation Option Ca – Plunger Lift with Cycle Optimization

***Mitigation Option Ca1* – Simple Cycle Optimization.**

Where plunger lifts exist and where they vent frequently, Partners can modify the plunger operation by using timers or other controllers that optimize the liquids unloading frequency.

This is essentially a subset or rather predecessor to applying "smart technology" outlined below. A timer or controller (e.g. pressure) may be installed on the well and engage the plunger lift (and liquids unloading events) such that the frequency of events is minimized, but the well is able to produce. Partners may be able to determine the timing in which liquids would build up in the well sufficient to cause the well to cease flowing. A timer could be set to control the frequency of the liquids unloading cycling based on the estimated time the well would fill with liquids. Another option would be to use a pressure controller to minimize the frequency of liquids unloading cycles. In this case, the pressure

[13] EPA. Lessons Learned: *Installing Plunger Lift Systems in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_plungerlift.pdf

controller would monitor the pressure of the well and the liquids unloading cycle would occur at a set pressure level (near the pressure point in which the well would shut in due to liquid burden).

Operational Considerations

The frequency of liquids unloading cycling would need to be established on a well by well basis. However the operating considerations are similar for plunger lifts since one is only “optimizing” the plunger lift cycles in order to minimize emissions associated with liquids unloading.

Mitigation Option Ca2 – "Smart" Well Technology[15]

Not all plungers vent, and even among those that do occasionally vent, some do not vent frequently. For those that vent frequently, "Smart" Well Technology[15] is an automated system that takes into account well conditions and determines when a plunger lift cycle needs to be actuated to determine optimally when the liquids should be unloaded.

Operational Considerations

The conditions for "smart" technology are the same as those for plunger lifts. Implementing this technology requires the installation of:

- Remote terminal unit with programmable logic controllers
- Tubing and casing transmitters
- Gas measuring equipment
- Control valve
- Plunger detector

Methane Emission Reduction Estimate
Emission reductions are a function of the flowing pressure and operational characteristics and do not lend themselves to generalization. Partners employing this option should determine baseline emissions before implementing this option and then evaluate emissions after implementation to determine emission reductions.

Economic Considerations
The cost for implementing "smart" technology is incremental above plunger lifts. One EPA Natural Gas STAR partner has estimated the cost for smart technology to be $5,700 to $18,000 per well[14]. This technology enables the user to maximize the effectiveness of a plunger lift. The user therefore sees additional increased gas production and therefore additional economic benefit.

Mitigation Option D – Pumps and Compressors

Pumps, gas lift, and wellsite compression may be mitigation measures implemented in some wells to abate venting associated with manual, intermittent and plunger lift liquids unloading in which atmospheric venting occurs.

Downhole Pumps, reciprocating (rod or beam) and rotating (progressive cavity): A rod (or beam) pump, either electric or natural gas, can pump the liquids to the surface. These methods can extend the lifetime of the well beyond that possible with the plunger lift, but will have normal operating and maintenance costs.

Gas Lift: Another potential technique to combat the liquids unloading issue in horizontal wells is gas lift. Gas lift systems send high-pressure gas into the casing of the well, which increases the pressure differential between the bottom of the well and the wellhead. The velocity of gas returning up the

[14] EPA. Lessons Learned: *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf.

tubing increases, allowing the gas to carry liquids from the well. The major requirement for gas lift is a readily available high-pressure wellsite compressor.

Sequential Lift: In addition, Muskegon Development Company has used a technology called sequential lift to combat liquid build-up. This technology uses a series of pumps that follow the horizontal well and pump liquids from the well. Muskegon Development Company reports that sequential lift was more effective than gas lift for managing liquids and minimizing emissions from their wells. The Artificial Lift R&D Council (ALRDC) collects and reports developments for horizontal gas wells.[15]

Operational Considerations

Example. A rod pump can remove liquids when there is a lower pressure drop than is needed for a plunger lift to work. Furthermore, the rod pump can remove the liquids regardless of the gas velocity, thereby extending the lifetime of the well beyond other liquid removal techniques.

Implementing this technology requires the installation of:

- Sucker rod and tubing
- Rod guides, or
- Pump, and
- Pump motor

Methane Emission Reduction Estimate

Example. In some cases, rod pumps can save an estimated 770 to 1,600 Mcf/well per year.[16]

Economic Considerations

Example. The cost for implementing a rod pump is estimated to be $25,900 to $51,800 with a maintenance cost of $1,300 to $19,500 per year, well treatment cost of $13,200, and electricity cost of $1,000 to $7,300 per year.[17] The economics of a rod pump include the upfront capital cost, the maintenance costs, and the volume of gas savings if the previous practice was blowing down the well, the revenue from increased or extended production (or both), the electricity cost, and the well treatment costs.

ESTIMATING MITIGATED EMISSIONS

For the purpose of this Technical Guidance Document, it is suggested that mitigated emissions be determined using an emissions hierarchy of direct measurement, engineering equations, and emissions factors.

For wells that employ foaming agents, surfactants, or velocity strings/tubing as a mitigation measure, the estimated mitigated emissions are the estimated emissions of the well prior to the mitigation (e.g. foaming agent) minus the estimated emissions after mitigation.

[15] Artificial Lift R&D Council (ALRDC), Artificial Lift in Horizontal Wells. "Selection of Artificial Lift Systems for Deliquifying Gas Wells" Prepared by Artificial Lift R&D Council. http://www.alrdc.com/recommendations/horizontalartificiallift/index.htm.
[16] Ibid.
[17] EPA. Lessons Learned: *Options for Removing Accumulated Fluid and Improving Flow in Gas Wells.* https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf.

For wells that are manually unloaded, but then converted to plunger lift liquids unloading, the mitigated emissions are the estimated emissions from manually unloading (presuming the same frequency as plunger lift cycles) minus the mitigated estimated emissions associated with plunger lift operations.

For wells that employ liquids unloading cycle optimization (e.g., intermittent timing on non-plunger lift wells and mechanical timers, pressure controllers, or "Smart" well technology on plunger lift wells), the estimated mitigated emissions are the estimated emissions of the well prior to the mitigation measure minus the estimated emissions after mitigation (i.e., reductions are primarily due to the reduced frequency and volume of venting).

For wells that employ or are equipped with liquid unloading methods that remove the liquids (e.g., beam pumps, submersible pumps, cavity pumps, gas lift, wellhead compression) from the well and "mitigate" the need to implement manual, intermittent, or plunger lift unloadings methods, the mitigated emissions would be the estimated emissions prior to mitigation minus estimated emissions after mitigation (which presumably should be zero since this mitigation measure abates the need for liquids unloading).

Emission Factors

Emissions factors for liquids unloading were developed from available public data are summarized in the Tables below.

Table 7.2: Methane Emission Factors for Liquids Unloading (Source: API and ANGA report[18])

Source	Methane Emission Factor	
	(thousand scm/year/well)	(thousand scf/year/well)
Liquids Unloading Venting – without using plunger lifts	9	304
Liquids Unloading Venting – using plunger lifts	14	345

[18] 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.

Table 7.3: Methane Emission Factors for Liquids Unloading (Source: Adapted from 2012 and 2013 reports to the US Greenhouse Gas Reporting Program[19])

Source	Methane Emission Factor	
	(scm/year/event)	(scf/year/event)
Liquids Unloading Venting – without using plunger lifts	96.3	3,400
Liquids Unloading Venting – using plunger lifts	4.7	166

Table 7.4: Methane Emissions Factors for Liquids Unloading (Source: UT Study[20])

Source	Methane Emissions Factor		
	scm/event	scf methane/event	Average Events/Year
Liquids Unloading without Plunger Lift (manual venting to atmosphere)			
< 10 events per year	609	21,500	2.9
11 to 50 events per year	682	24,100	20.3
51 to 200 events per year	991	35,000	75.6
Liquids Unloading with Plunger Lift			
Plunger Lift < 100 events/year	273	9,650	7.7
Plunger Lift > 100 events/year	36	1,260	1200

[19] 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).
[20] "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.

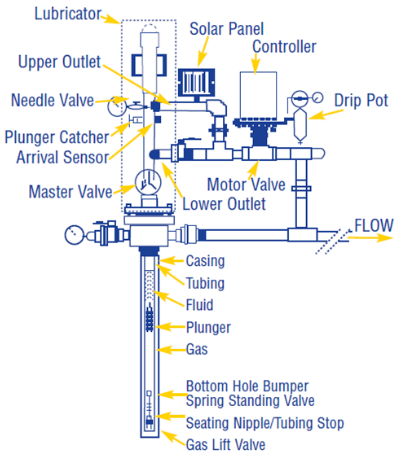
Exhibit A – Well Venting for Liquids Unloading[21]

Taken by Arlington Fire Department. From Star-Telegram article

Exhibit B – Well Liquids Unloading with Plunger Lift System[22]

[21] CCAC Oil and Gas Methane Partnership: webinar March 30, 2015: "Well Venting/Flaring During Well Completion for Hydraulically Fractured Gas Wells and Well Venting for Liquids Unloading," presentation by UNEP

[22] Natural Gas STAR Producers Technology Transfer Workshop, College Station, Texas, May 17, 2007: "Producers Best Management Practices and Opportunities," presentation by EPA


Lubricator
Solar Panel
Controller
Upper Outlet
Needle Valve
Drip Pot
Plunger Catcher
Arrival Sensor
Motor Valve
Master Valve
Lower Outlet
FLOW
Casing
Tubing
Fluid
Plunger
Gas
Bottom Hole Bumper
Spring Standing Valve
Seating Nipple/Tubing Stop
Gas Lift Valve


CEO

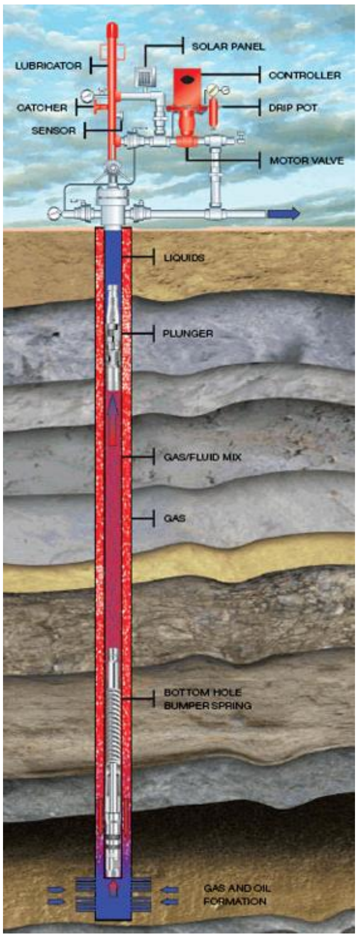
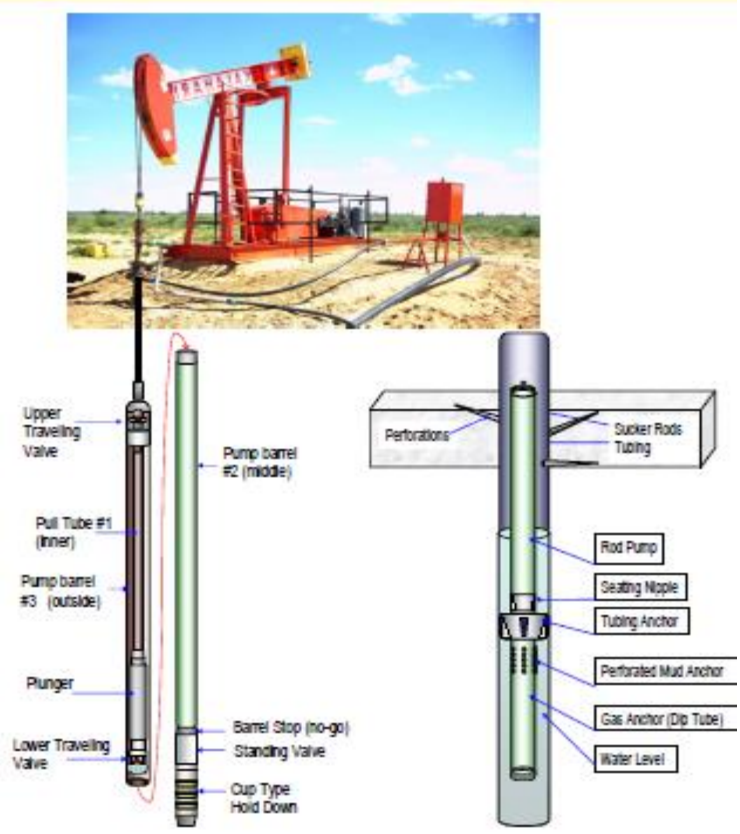

SOLAR PANEL
LUBRICATOR
CONTROLLER
CATCHER
DRIP POT
SENSOR
MOTOR VALVE
LIQUIDS
PLUNGER
GAS/FLUID MIX
GAS
BOTTOM HOLE
BUMPER SPRING
GAS AND OIL
FORMATION

Exhibit C – Well Liquids Unloading with Beam Pump[23]



[23] CCAC Oil and Gas Methane Partnership: webinar March 30, 2015: "Well Venting/Flaring During Well Completion for Hydraulically Fractured Gas Wells and Well Venting for Liquids Unloading," presentation by UNEP