NMED/EMNRD METHANE ADVISORY PANEL

WORKOVERS/LIQUIDS UNLOADING REPORT

Discussion for MAP members on September 12, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

Manual Liquid Unloading:

Managing wellbore liquid build-up in gas wells is fundamental to maintaining production, avoiding early abandonment of wells and maximizing resource recovery. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production declines, wellbore (tubing) velocity goes down, and liquid loading begins to occur in the wellbore. Liquid loading begins when the velocity up the production string is not sufficient to lift liquids up to the surface at a pressure that will allow production to overcome the surface equipment and out of the wellbore. While pressure is a factor, it is generally a lack of velocity, which causes liquids to accumulate in the wellbore (i.e., “to load/load up”). Gas well unloading is a complex field of science and engineering where a large number of different technologies, tools and practices must be matched to an individual well’s characteristics at each stage of its lifecycle to most efficiently manage liquids and maintain economic viability of the well. No single technique will be adequate or appropriate across the full lifecycle of a well.

As a well moves through its lifecycle, the appropriate approach to managing liquids changes. New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and velocity declines and eventually a point is reached where liquids loading begins to be an issue. The time at which liquids loading occurs is dependent on the reservoir characteristics and varies from well to well. At the onset of liquids unloading, techniques that rely on the reservoir energy are typically used. These include:

- **Intermitting:** Shutting in a well for a period of time to allow the reservoir to "refill" the pressure and volume "void" in the near-wellbore reservoir so that when the well is restarted the production rate and velocity are higher and the well can "unload" liquids through the normal production route to sales;
- **Velocity strings:** Installing a smaller diameter tubing string in the well that increases the flow velocity at a given production rate sufficiently to drag liquids up the wellbore and prevent liquid loading;
- **Surfactants and foaming agents**: Introducing surfactants and foaming agents to the bottom of a well (various techniques are used) creating foam with lower specific gravity which enables liquids to be carried up the wellbore at lower velocities.

These techniques can be used individually or in combination to manage wellbore liquids and maintain production.

Eventually a well will reach a point where the reservoir energy is not sufficient to remove the liquids from the well and adding energy to the well is necessary to continue production. Common approaches are to install artificial lift. Two common methods are:

- Installing a plunger lift system that changes the dynamic for removing liquids from velocity to differential pressure between the bottom-hole and the surface/gas collection line; or
- Installing wellhead compression that lowers the surface back-pressure on a well, increases production rate and flowing velocity, and increases the differential pressure between the reservoir and the collection/sales line.

There are a number of different pump types and gas lift systems, each more effective in some respects than others. Installation of a system to add energy to a well is an economic decision based on whether the continuing production will be sufficient to support the costs of installing and operating a pump or gas lift system.

There are some cases where the need to create additional differential pressure is necessary to manually unload accumulated liquids. These cases include onsite or downstream equipment downtime in the gas gathering system.

One item of clarification is that deliquification, liquid unloading and venting are not synonymous terms. Liquids can and are routinely removed from gas wells without venting.

Workovers:

Some wells may need to be re-stimulated in a previously completed formation or in a new reservoir in the same wellbore. These operations are called recompletions. Additionally, some wells will require supplementary maintenance to maintain production or minimize the decline in production and are referred to as workovers. Typical workovers include rod, tubing and casing repairs, siphon string or artificial lift installation, paraffin removal, and pump repairs.

Both recompletions and workovers differ from completions in that they are performed on wells that that have previously been completed and have produced some reservoir fluids (water, oil, and/or natural gas). These wells will have to be prepared before recompletion or workover operations can begin. If the well is still producing and/or has pressure, the well will need to be blown down before it is safe to remove the tubing head and install the blowout preventers (BOP's). The well pressure can be decreased by opening the casing to the sales line or the suction of a wellsite compressor. In many cases the fluids in the wellbore will build up to the point the well dies, this is referring to the instance where the hydrostatic pressure of the accumulated fluids is equal to the reservoir pressure. In some cases, it will be necessary to pump water or other fluids in the wellbore to kill the well. As a safety precaution, after the BOP's are installed the well is usually vented to atmosphere via a tank.

In the case of a recompletion, after the well is prepared (well blown down, BOP's installed, and the tubing removed) the stimulation and flow back will be the same as the issues that were presented in the COMPLETIONS/STIMULATIONS Report. A recompletion would be a stimulation of an existing well, in a different horizon, that has already been completed. The preparation of the well for a recompletion is the source covered in this Workovers/Liquids Unloading Report. The preparation of the well, as mentioned above is the process in which the pressure on the wellbore is reduced to atmospheric pressure by venting the well through an atmospheric storage tank. The pressure is relieved to atmosphere to ensure the well can safely be worked on (workover) or recompleted.

Workovers are usually short duration projects that only last a few days or weeks at the most. After the well is prepared (well blown down and the BOP's installed) the workover operations can begin. For the safety of the rig crew, the well is usually allowed to vent to atmosphere via a tank for the duration of the workover. Since these operations are usually performed during daylight hours, the well is shut in or returned to the sales line at the end of the day.

Provide the segment(s) of the industry that the equipment or process is found:

This process is found in the oil and gas production segment of the industry.

Describe how the equipment or process is used:

The production from the wellbore (tubing and/or casing) is routed to an atmospheric tank to create the differential pressure necessary to manually unload the liquids accumulated in the wellbore or to make the wellbore safe to perform downhole maintenance.

Provide the common process configurations that use this equipment or process:

The liquids unloading process applies primarily to gas wells. The workover operations apply both to oil and gas wells.

What is the distribution of the equipment or process across business segments?

This process primarily relates to the onshore oil and gas production sector.

How has this equipment or process evolved over time?

The technology for gas well deliquification has advanced over time and operators have adopted many wellbore best management practices that have minimized the amount of manual liquids unloading events necessary to keep well production optimized. Advanced planning to reduce the wells pressure prior to blowing the well down have resulted in reduced emissions.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

The source of methane emissions for liquids unloading and workover operations is the venting of a well to an atmospheric tank.[1]

New Wells:

New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. New wells normally do not require downhole maintenance but if a workover is necessary the process is the same for new and existing wells.

Existing Wells:

The methane emissions for workovers/liquids unloading operations comes from the venting of the well through atmospheric tanks to unload liquids or make the wellbore safe to preform downhole maintenance.

How are the emissions calculated for this equipment or process?

The formulas included below reflect the calculation methodology for estimating emissions from manual liquids unloading events under the EPA Greenhouse Gas Reporting Program (GHGRP). Note that emissions from workovers are combined with completions in the GHGRP program. This calculation methodology contains 3 layers of conservatism in estimating emissions that result in a gross overestimation of emissions. First, the first term of the calculation methodology assumes the full wellbore contains gas only, which does not account for the space occupied by liquid. This asumption over estimates the volume of gas in the column and, therefore, the amount of gas vented. Also, if the tubing or casing were occupied by gas only, a manual liquids unload would not be required. Second, the GHGRP calculation methodology also assumes these activities are no more than 1 hour and 0.5 hour, respectively. After this timeframe, the method assumes the well is venting at the production rate, which leads to another layer of overestimation of emissions. Third, during a manual liquids unloading activity, the valve that allows for flow to the tank may be open for period of time with no liquid/gas movement, therefore, the method assumes flow when there may not be.

[1] Leaks, upsets and other fugitive emissions are addressed in the leak detection and repair report.

Blowdown volumes for wells <u>without</u> plungers (assumes casing)

$$\left(\begin{Bmatrix} Physical\ Volume\ of\ Casing \\ Being\ Blown\ Down \\ [ft^3] \end{Bmatrix} \times \begin{Bmatrix} Convert\ to\ Atmospheric \\ Pressure \end{Bmatrix}\right) + \left(\begin{Bmatrix} Avg\ Gas \\ Flowrate \\ \left[\frac{scf}{hr}\right] \end{Bmatrix} \times \begin{pmatrix} Blowdown \\ Duration \\ [hrs] \end{pmatrix} - 1\right) \times \begin{pmatrix} 1\ [if\ duration\ longer\ than\ 1\ hr] \\ or \\ 0\ [if\ duration\ shorter\ than\ 1\ hr] \end{pmatrix}\Bigg)$$

Blowdown volumes for wells <u>with</u> plungers (assumes tubing)

$$\left(\begin{Bmatrix} Physical\ Volume\ of\ Tubing \\ Being\ Blown\ Down \\ [ft^3] \end{Bmatrix} \times \begin{Bmatrix} Convert\ to\ Atmospheric \\ Pressure \end{Bmatrix}\right) + \left(\begin{Bmatrix} Avg\ Gas \\ Flowrate \\ \left[\frac{scf}{hr}\right] \end{Bmatrix} \times \begin{pmatrix} Blowdown \\ Duration \\ [hrs] \end{pmatrix} - 0.5\right) \times \begin{pmatrix} 1\ [if\ duration\ longer\ than\ 0.5\ hr] \\ or \\ 0\ [if\ duration\ shorter\ than\ 0.5\ hr] \end{pmatrix}\Bigg)$$

<u>GHGRP:</u>

(f)*Well venting for liquids unloadings.* Calculate annual volumetric natural gas emissions from well venting for liquids unloading using one of the calculation methods described in paragraphs (f)(1), (2), or (3) of this section. Calculate annual CH4 and CO2 volumetric and mass emissions using the method described in paragraph (f)(4) of this section.

(1)*Calculation Method 1.* Calculate emissions from wells with plunger lifts and wells without plunger lifts separately. For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see § 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, install a recording flow meter on the vent line used to vent gas from the well (*e.g.,* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate the total emissions from well venting to the atmosphere for liquids unloading using Equation W-7A of this section. For any tubing diameter group and pressure group combination in a sub-basin where liquids unloading occurs both with and without plunger lifts, Equation W-7A will be used twice, once for wells with plunger lifts and once for wells without plunger lifts.

Ea=FR∑hp=1Tp(Eq. W-7A)Ea=FR∑p=1hTp(Eq. W-7A)

Where:
Ea = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions, a, in cubic feet. Calculate emission from wells with plunger lifts and wells without plunger lifts separately.
h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin either with or without plunger lifts.
p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.
Tp = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year. If the available venting data do not contain a record of the date of the venting events and data are not available to provide the venting hours for the specific time period of January 1 to December 31, you may calculate an annualized vent time, Tp, using Equation W-7B of this section.
FR = Average flow rate in cubic feet per hour for all measured wells of the same tubing diameter group and pressure group combination in a sub-basin, over the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

Tp=HRpMPp×Dp(Eq. W-7B)Tp=HRpMPp×Dp(Eq. W-7B)

Where:
HRp = Cumulative amount of time in hours of venting for each well, p, during the monitoring period.
MPp = Time period, in days, of the monitoring period for each well, p. A minimum of 300 days in a calendar year are required. The next period of data collection must start immediately following the end of data collection for the previous reporting year.

D_p = Time period, in days during which the well, p, was in production (365 if the well was in production for the entire year).

(i) Determine the well vent average flow rate (“FR” in Equation W-7A of this section) as specified in paragraphs (f)(1)(i)(A) through (C) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category. Calculate emissions from wells with plunger lifts and wells without plunger lifts separately.

(A) Calculate the average flow rate per hour of venting for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total annual flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) Apply the average hourly flow rate calculated under paragraph (f)(1)(i)(A) of this section to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) Calculate a new average flow rate every other calendar year starting with the first calendar year of data collection. For a new producing sub-basin category, calculate an average flow rate beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2)*Calculation Method 2.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W-8 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \quad \text{(Eq. W-8)}$$

Where:
E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.
W = Total number of wells with 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 per well, p.
0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
CD_p = Casing internal diameter for each well, p, in inches.
WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.
SP_p = For each well, p, shut-in pressure or surface pressure for wells with tubing production, or casing pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure is not available for each well, you may determine the casing pressure by multiplying the tubing pressure of each well with a ratio of casing pressure to tubing pressure from a well in the same sub-basin for which the casing pressure is known. The tubing pressure must be measured during gas flow to a flow-line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading when the well production is impeded by liquids loading or closed to the flow-line by surface valves.
SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. 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.
1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
q = Unloading event.
$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(3)*Calculation Method 3.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.

$$E_s = \sum_{p=1}^{W} \left[V_p \times \left(\left(0.37 \times 10^{-3}\right) \times TD_p^2 \times WD_p \times SP_p \right) + \sum_{q=1}^{V_p} \left(SFR_p \times \left(HR_{p,q} - 0.5 \right) \times Z_{p,q} \right) \right] \quad \text{(Eq. W-9)}$$

Where:
Es = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.
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.
Vp = 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).
TDp = Tubing internal diameter for each well, p, in inches.
WDp = Tubing depth to plunger bumper for each well, p, in feet.
SPp = Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.
SFRp = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.
HRp,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 is less than 0.5 then Zp,q is equal to 0. If HRp,q is greater than or equal to 0.5 then Zp,q is equal to 1.

(4) Calculate CH4 and CO2 volumetric and mass emissions from volumetric natural gasemissions using calculations in paragraphs (u) and (v) of this section.

EDF Synthesis:
We did not incorporate liquids unloading data from Allen et al 2014b (*) because the GHGRP provided more detailed data on event counts and emission rates; the Allen et al estimate of 2012 national emissions from liquids unloading was within a few percent of the GHGRP estimate.

The data suggest that the central estimate of national emissions from unloadings (270 Gg/yr, 95% confidence range of 190–400 Gg) are within a few percent of the emissions estimated in the EPA 2012 Greenhouse Gas National Emission Inventory (released in 2014), with emissions dominated by wells with high frequencies of unloadings. (*)

(*) D. T. Allen, D. W. Sullivan, D. Zavala-Araiza, A. P. Pacsi, M. Harrison, K. Keen, M. P. Fraser, A. Daniel Hill, B. K. Lamb, R. F. Sawyer, J. H. Seinfeld, Methane emissions from process equipment at natural gas production sites in the United States: Liquid unloadings. Environ. Sci. Technol. 49, 641–648 (2015). doi:10.1021/es504016r Medline

What data is available to quantify emissions/waste for this equipment or process?

https://www.epa.gov/ghgreporting

About 85% of the gas wells in the U.S. have production rates low enough to have liquids loading issues, and only about 13% have liquids unloading venting to assist liquid removal in 2012 (gross up of GHGRP data).

- The frequency and amount of venting to assist liquids unloading is highly skewed, with 10 of the 1991 non-zero datasets reported at the "sub-basin" level (less than 0.5%) datasets accounting for more than 50% of the emissions reported;
- At the facility (basin) and reporter level (251 non-zero data sets) the top 1 (0.4%) accounted for about 37% of the total reported emissions; and

- The top 3 (1.2%) accounted for over 50% of the total methane reported and the top 11 accounted for over 75% of the reported methane emissions.

Methane emissions attributed to LU venting are a fairly small portion of the industry emissions in the GHGI and are trending down

GHGI - 2016 (2018 release) LU Venting
6.1% of Natural Gas Systems E&P CH4
2.0%of Natural Gas Systems CH4
1.6% of Natural Gas + Petroleum Systems CH4

GHGRP, Allen et al 2014b, operator data, etc.

According to the Synthesis* study, EDF estimates about 21,700 metric tons CH4 from unloading in NM in 2017. Better records of unloading process information would provide better estimates of total emissions. Not surprisingly, the majority of these emissions occur in the San Juan Basin.

According to the EDF Synthesis study* data, 8.5% of production CH4 emissions are attributable to LU in NM (excluding abnormal process emissions, for consistency with GHGI) vs. 4.9% nationally (or 6.1% per GHGI for the US). This demonstrates a disproportionately high percentage of LU emissions in NM versus the national rate. On tribal lands in NM, Synthesis* data indicates liquids unloading emissions account for 9.9% of production emissions, even higher than the New Mexico total rate.

*EDF Synthesis study:
https://science.sciencemag.org/content/361/6398/186.full?ijkey=42lcrJ/vdyyZA&keytype=ref&siteid=sci

What are the data gaps in quantifying emissions/waste for this equipment?

Unloading emissions are more often estimated than measured. It is important that operators record process information for better estimates of unloading emissions, such as **number of unloading events and duration of each event**. Operators should also indicate if/how an artificial or plunger lift was utilized.

Further, the Subpart W Greenhouse Gas Reporting Program (GHGRP) requirements only apply to facilities above the emissions threshold. Therefore, not all unloading events are reported under the program.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

The cost for supervision of manual liquid unloading events is dependent upon each unique situation. Additional labor cost of having a lease operator onsite is variable, which make it very difficult to establish a fixed value or even a range.

What are the annualized operating costs for the equipment or costs associated with the process?

N/A

If the equipment or process is powered, what are the costs?

N/A

What are the maintenance and repair costs for existing or new equipment?
N/A

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?
Operators have developed and employed several wellbore best management practices over the life of the well to avoid the need to perform manual liquids unloads. These best management practices include revisiting the application of refined technology in terms of artificial lift. In order to increase gas sales and reduce emissions/waste during these manual liquids unloading activities, operators should monitor manual liquids unloading events onsite, within close proximity or via remote telemetry to return the wells to normal production operation as soon as possible. Advanced planning to reduce pressure prior to blowing the well down has resulted in reduced emissions.

1. Create differential pressure to minimize the need for venting during unloading activities (artificial lift engine/pump jack, electric submersible pump, etc.)
2. Plunger lifts including automated plunger lifts
3. BMPs - Operators onsite to close vents and monitor the unloading events

Between artificial lift engines, plunger lifts, and supervised manual unloading, one option will result in the lowest emissions relative to the others. This lowest emitting option will serve to mitigate emissions relative to the others, and should therefore be selected and employed by the operator for liquids unloading at a site.[2]

New Wells:
New wells typically have sufficient production rates and flowing velocity so that manual liquids loading is not required. New wells do not require workovers. Workovers are the downhole maintenance activities performed on existing wells that have previously been capable of producing hydrocarbons.

Existing Wells:
In order to increase gas sales and reduce emissions/waste during manual liquids unloading activities, operators should monitor manual liquids unloading events onsite, within a close proximity or via remote telemetry to return the wells to normal production operation as soon as possible.

How have the emission/waste reductions been measured?
New Mexico Oil and Gas Association report on methane sources and mitigation.
GHGRP 2011-2016 https://www.nmoga.org/methaneroadmap

GHGRP emissions trends data is the most reliable source to establish emission reductions, as described in Section 3 below.

Various studies have measured or modeled emissions from manual liquids unloading events.

Characterizing Regional Methane Emissions from Natural Gas Liquid Unloading

[2] The application of artificial lift is very dependent on the specific characteristics of each well. The operating parameters of the wells will dictate the appropriate artificial lift application. The misapplication of artificial lift could result in an increase in methane emissions in the case of plunger lift installations.

https://pubs.acs.org/doi/abs/10.1021/acs.est.8b05546#

Temporal Variations in Methane Emissions from an Unconventional Well Site
https://pubs.acs.org/doi/pdf/10.1021/acsomega.8b03246

Temporal Variability Largely Explains Difference in Top-down and Bottom-up Estimates of Methane Emissions from a Natural Gas Production Region
https://www.pnas.org/content/115/46/11712

Comparison of methane emission estimates from multiple measurement techniques at natural gas production pads
https://www.elementascience.org/article/10.1525/elementa.266/

Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially-Resolved Aircraft Measurements
https://pubs.acs.org/doi/10.1021/acs.est.7b01810

Methane Emissions From Process Equipment At Natural Gas Production Sites In The United States: Liquid Unloadings
https://pubs.acs.org/doi/abs/10.1021/es504016r

Measurements Of Methane Emissions At Natural Gas Production Sites In The United States
https://www.pnas.org/content/110/44/17768

If the artificial lift engine operates properly, the only emissions will be combustion. Depending on conditions, plunger lifts can reduce emissions 90% compared to unmitigated venting. (Source: ICF MACC Report, 2014, available at , https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf)

How have other jurisdictions, including state, federal, and tribal, reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

Outside of the initial well preparation the number of activities that can be accomplished under the heading of Recompletions/Workovers is so varied with multiple variables that are well specific, regulating venting and emissions associated with these activities is not feasible. Use of best management practice to manage wellbore pressure makes the most sense because it allows operators to determine the best way to reduce venting on a case by case basis specifically from each well as the situation dictates.

The complexity of liquids unloading is why EPA concluded for NSPS OOOOa that imposing specific regulatory requirements for venting and emissions associated with managing wellbore liquids is not feasible. Requirements for monitoring the activity to manage venting makes the most sense because it allows operators to determine the best way to manage manual unloading on a case by case basis specifically from each well as it changes over time.

BLM's final waste prevention rule requires operators to minimize venting and the need for venting and operators must consider alternatives to manual venting and determine if they are infeasible; if manual venting, operators must remain onsite. BLM, 81 Fed. Reg, 83008 (Nov. 18, 2016)

4. 2016 rule: The final rule requires an operator to: (1) Minimize gas vented to unload liquids, consistent with safe operations; (2) optimize the operation of the plunger lift or automated well control system, at wells equipped with such a system, to minimize gas losses from the system to the extent possible; (3) consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly, prior to manually purging a

well for the first time; and (4) comply with specified procedures and document venting events when unloading liquids by manual well purging… The operator must notify the BLM by Sundry Notice within 30 days after the first liquids unloading by manual or automated well purging after the effective date of the rule. Additionally, operators must notify the BLM by Sundry Notice within 30 days after the following conditions are met: (1) The cumulative duration of manual well purging events for a well exceeds 24 hours during any production month; or (2) the estimated volume of gas vented in the process of conducting liquids unloading by manual well purging for a well exceeds 75 Mcf during any production month.

5. The requirements to minimize wasted gas remain essentially the same between the two rules. The main difference between the 2016 and 2018 Rules are that the 2016 Rule required recordkeeping and reporting of liquids unloading events, and the 2018 Rule removed those requirements.

Colorado State Regulation to minimize methane emissions in the oil and gas industry:
Colorado, Reg.7, Section XVIII.H.,
https://drive.google.com/file/d/168v7vMsFJtS7D8BWlnMbaXWA6uZUIyj8/view
requires operators to use best management practices to reduce emissions and operators must remain onsite during manual unloading. Colorado is proposing new recordkeeping and reporting requirements to gather better data on emissions and BMPs to reduce emissions.

Wyoming requires operators use BMPs to minimize emissions and operators must remain onsite during manual unloading (see "blowdown and venting" requirements).
http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf (pps. 13, 19, 24)

Pennsylvania requires operators use BMPs to minimize emissions. GP-5A, Section L,
http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=36120

<u>What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?</u>

<u>Liquids Unloading:</u>

- Create differential pressure to eliminate the need to vent a well to unload liquids.
  - Equalize the well
  - Allow the well to build pressure
- Reduce wellbore pressure as much as possible prior to opening to atmosphere via storage tank.
  - If possible route the initial volume of gas into the sales line prior to venting. Monitor the pressure and the flowrate to determine the optimal time to vent the well to create the differential pressure to unload the well.
- Monitoring manual liquid unloading events onsite, within a close proximity or via remote telemetry to return the wells to normal production operation as soon as possible.

<u>Recompletions/Workovers:</u>

- Open casing to the sales line or the wellhead compressor to reduce the wellbore pressure prior to venting.
  - Equalize with line pressure or compressor suction pressure prior to blow down operations

- Route gas flow to sales overnight if possible

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
BMP – operator onsite monitoring	Operator	In use	High	Low
Artificial lift engine (rod pump)	https://ediplungerlift.com/products/engine-packages/	In use	Medium-High[3]	Medium
Plunger Lifts	https://ediplungerlift.com/products/plungers/	In use (common)	High	Low-Medium

It is important to note that artificial lift deployment is a process that operators carry out to maximize production and production value currently. A well may start off with sufficient production rates to lift liquids out of the wellbore but as the wells production declines below the critical rate, artificial lift must be implemented to optimize production. The operator will select the best artificial lift method based on the well parameters and current conditions. The manual liquid unloading events being discussed in this report are primarily related to the action that must be taken due to an abnormal operating condition, such as an increase in the gas sales line pressure. The increased line pressure causes the well to load up with liquid and production to decrease. This applies to both free flowing wells and wells with plunger lift installations. The act of venting the well through an atmospheric storage tank creates the differential pressure necessary to unload the liquids from the well and return the well back to normal operation.

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

Artificial lift engines

[3] The feasibility of installing a rod pumping system on a well depends on a number of variables such as the depth, casing size and production rates.

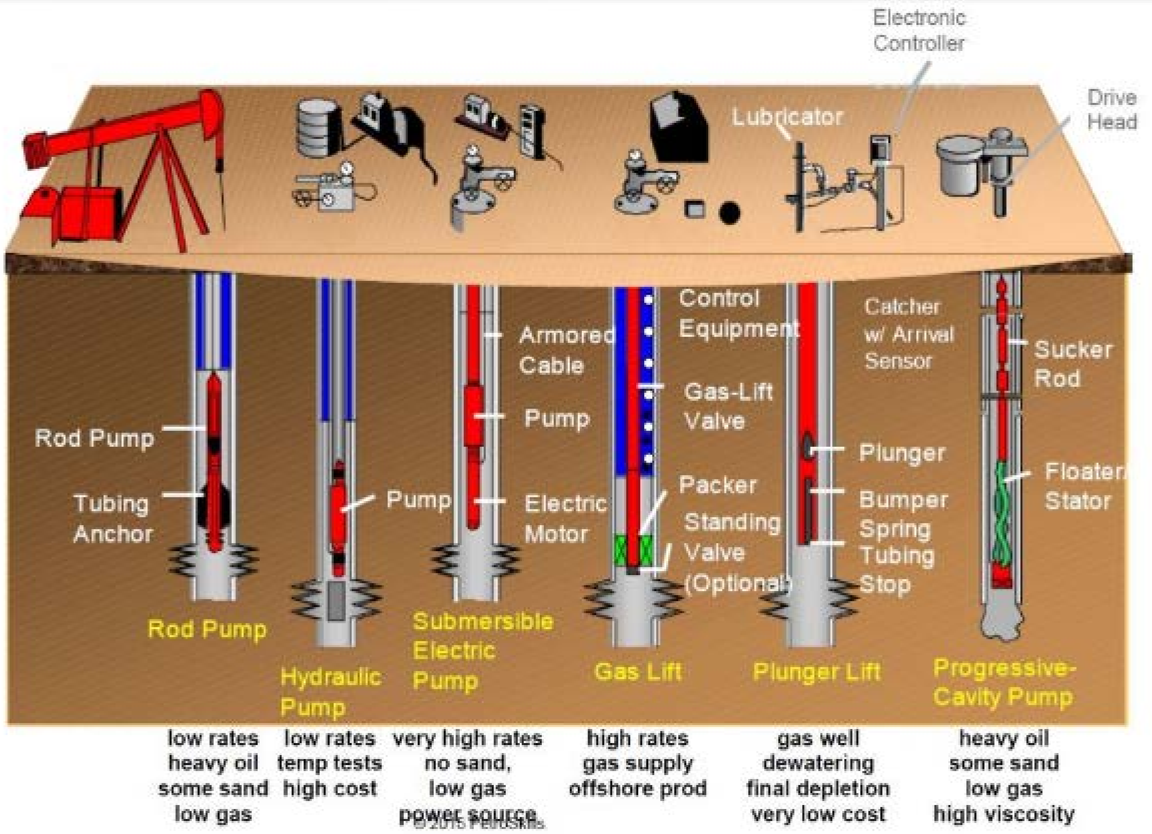

Figure 1-1 *Examples of the primary methods of artificial lift.*

Source: https://www.petroskills.com/blog/entry/00_totm/sept17-sub-totm-artificial-lift?page=5#.XZO2dm9KjIU

As shown above the various artificial lift methods have limitations and drawbacks. It is critically important to consider the application of artificial lift on an individual well basis.

What are the pros and cons of the alternatives?

Pro: The act of liquids unloading increases production. Mitigating unloading emissions increases production and minimizes emissions. Artificial lift engines can prolong the life of a well and operate at lower pressures than plunger lifts (i.e., wider operating range). (*source*: https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-liquids-unloading.pdf)

Con: external power source required, higher cost

What is needed and available for new wells?

See above

What is needed and available for existing wells?

See above

What technology alternatives exist for this equipment or process itself?

Plunger lifts (See above schematic)

There are many artificial lift options available and must be selected based on the well parameters and wellsite conditions.

What are the pros and cons of the alternatives?

See above

Pro: The act of liquids unloading increases production. Mitigating unloading emissions using plunger lifts increases production and minimizes emissions. Estimates indicate production increase of 3 to 300,000 scf/day.

Con: Plunger lifts can operate at low-pressure wells but they do have pressure limits.

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

The cost to achieve methane emission reductions by monitoring the manual venting of a well is tied to the incremental labor cost associated with monitoring each event. The cost to monitor each event is unique in terms of the well configuration, associated pressures (tubing, casing and line).
The cost to reduce the wellbore pressure prior to a workover operation is minimal and is usually offset by the sales proceeds of the gas being sold.

Depends on reduction technology, effectiveness and gas price. Increased productivity in addition to cost benefits of the saved gas can lead to overall savings for artificial lift engines or plunger lift systems.

What would be the implementation cost?
For new wells?

N/A

Based on results reported by Natural Gas STAR Partners, the cost of implementing artificial lift systems range from $41,000 - $62,000. This is an old report and estimates have likely decreased.[4]

Gas STAR estimates for plunger lift installation range from $2,500 to $10,000 (*Installing Plunger Lift Systems In Gas Wells* http://epa.gov/gasstar/documents/ll_plungerlift.pdf). Some operators estimate $15,000 (ICF 2014).

For existing wells?

The cost of monitoring the manual liquids unloading events depends on how long it takes to unload the well.

Are there low-cost solutions available?

Some BMPs, like having an operator onsite to monitor unloading events, are very low cost.

[4] The cost of artificial lift installation is highly variable depending on the application. The range provide from the Gas STAR Partners does not reflect the cost of all artificial lift cost. The cost of a rod pump installation could exceed $500,000.00 depending on well depth and production desired pump capacity.

Other methods (like plunger lifts or lift engines) have higher implementation costs, but are often paid for by the additive benefits of increased productivity and saved gas. In fact, ICF estimates an overall benefit of $0.05/Mcf of methane reduced by installing plunger lifts.
(Source: https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf)

If a solution is high-cost, why is that the case?

Artificial lift engines and plunger lifts require technology implementation.

Are there additional technical analyses needed to refine benefits/costs estimates?
N/A

Can develop cost-benefit estimates with industry input.

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

Manual Liquids Unloading:
The lease operators are already deployed in the field to monitor manual liquids unloading events; it is a matter of prioritizing the efforts for monitoring manual liquids unloading events. Recompletion and Workover rig supervisors are experienced and trained in the best ways to minimize venting during the initial well blowdown.

Plunger Lifts and Artificial lift engines:
Many operators already utilize plunger or artificial engine lifts for liquids unloading (deliquification) activities. Indeed, one of these technologies is likely to result in less unloading emissions than manual unloading. In the event that either plunger lifts or artificial lift engines would lead to less methane emissions relative to manual unloading, an operator should verify that the lift option is technically feasible and implement that technology mitigation option for unloading at the facility.[5]

What is the useful life of equipment?
N/A

What are the maintenance and repair requirements for equipment required for methane reduction?
N/A

How would emissions be detected, reductions verified and reported?
Each venting event is timed and the emission volume calculated and reported to EPA under the GHGRP program and can be trended over time as illustrated below.

[5] The application of artificial lift is very dependent on the specific characteristics of each well. The operating parameters of the wells will dictate the appropriate artificial lift application. The misapplication of artificial lift could result in an increase in emissions in the case of plunger lift installations.

As EDF has noted, due to the reporting threshold and fluctuations in well counts, production, location, and age, the GHGRP data does not reflect all facilities or unloading events or trends thereof. Therefore, GHGRP trends should be considered in that context and not relied upon to accurately represent true liquids unloading emissions trends over time.

In addition to current estimation and reporting methods (see section 2), operators can also directly measure unloading event emissions.[6]

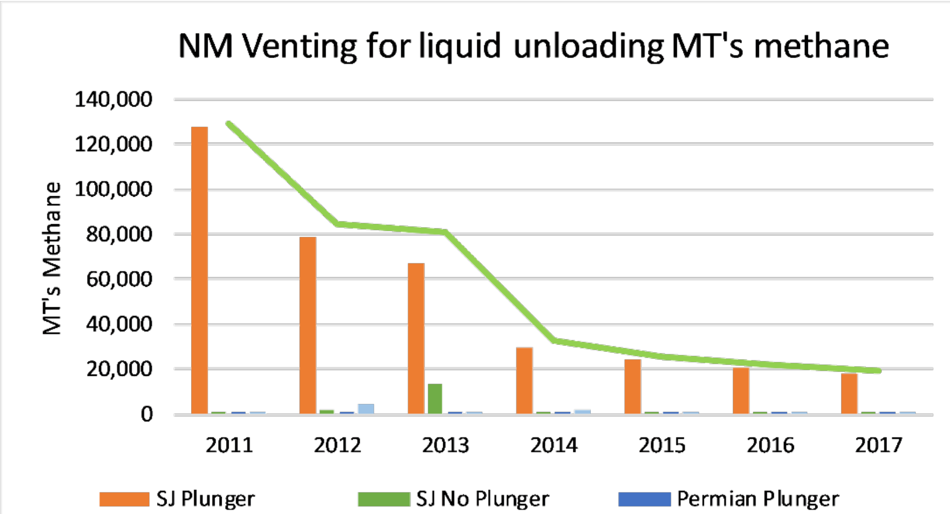

Figure 1: NM LU venting trends

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

EPA does not regulate liquids unloading.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

N/A

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

N/A

[6] Accurate direct measurement is difficult and can result in backpressure that will impede the process of unloading or blowing down a well.

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc?):

Safety is a core value for the industry. Being able to safely and effectively unload or blow down a well is a key point to keep in mind with methane reduction efforts during these activities.