Minimizing Emissions While Manually Unloading Unconventional Shale Gas Wells: An Applied Practice – Appalachian Basin

2019 Natural Gas Star and Methane Challenge Workshop

Jeff Formica VP – EHSQ

Seneca Resources

Safe Harbor For Forward Looking Statements

This presentation may contain "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995, including statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," and similar expressions. Forward-looking statements involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished.

In addition to other factors, the following are important factors that could cause actual results to differ materially from those discussed in the forward-looking statements: changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing; delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators; governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal; financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions; changes in the price of natural gas or oil; impairments under the SEC's full cost ceiling test for natural gas and oil reserves; factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; changes in price differentials between similar quantities of natural gas or oil sold at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations; other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date; the cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company; uncertainty of oil and gas reserve estimates; significant differences between the Company's projected and actual production levels for natural gas or oil; changes in demographic patterns and weather conditions; changes in the availability, price or accounting treatment of derivative financial instruments; changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities; changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services; the creditworthiness or performance of the Company's key suppliers, customers and counterparties; the impact of information technology, cybersecurity or data security breaches; economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war; significant differences between the Company's projected and actual capital expenditures and operating expenses; or increasing costs of insurance, changes in coverage and the ability to obtain insurance.

Forward-looking statements include estimates of oil and gas quantities. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. Other estimates of oil and gas quantities, including estimates of probable reserves, possible reserves, and resource potential, are by their nature more speculative than estimates of proved reserves. Accordingly, estimates other than proved reserves are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosure in our Form 10-K available at www.nationalfuelgas.com. You can also obtain this form on the SEC's website at www.sec.gov.

For a discussion of the risks set forth above and other factors that could cause actual results to differ materially from results referred to in the forward-looking statements, see "Risk Factors" in the Company's Form 10-K for the fiscal year ended September 30, 2018 and the Forms 10-Q for the quarter ended December 31, 2018, March 31, 2019, and June 30, 2019. The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date thereof or to reflect the occurrence of unanticipated events.

Outline

- Seneca Resources Company and National Fuel Gas Overview
- Area of Study
- Loading Causes
- Prevention is a Huge Part of the Cure
- Benefits of Going Ventless – Field Example
- Early Action Steps – Plunger Lift
- Manual Unloading
- Take Aways

Company Overview

Upstream	Midstream	Downstream
		
Exploration & Production	**Gathering**	**Utility**
SENECA RESOURCES	National Fuel Gas Midstream	National Fuel Distribution Corporation
	Pipeline & Storage	**Energy Marketing**
	National Fuel SUPPLY CORPORATION; empire pipeline A National Fuel Gas Company	NFR NATIONAL FUEL RESOURCES, INC. DEREGULATED NATURAL GAS EXPERTISE www.NFRinc.com

Area of Study

E&P and Gathering

National Fuel

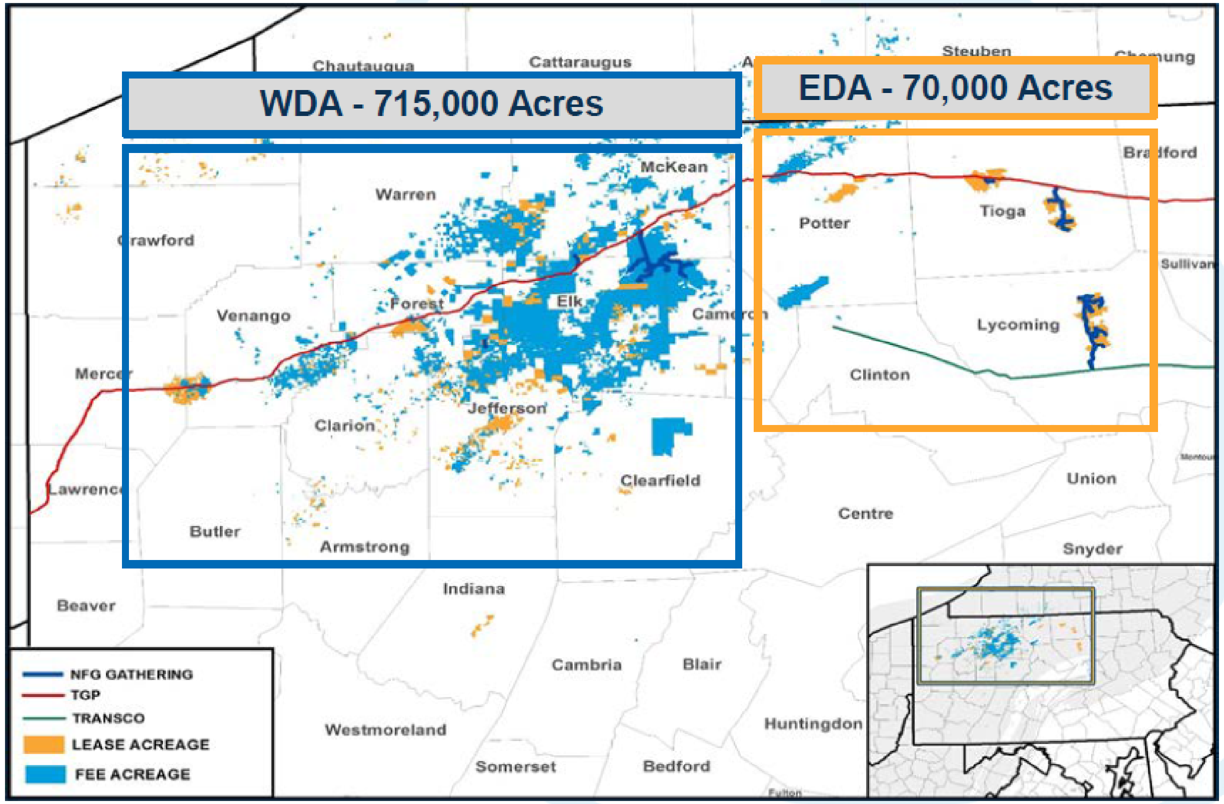
Significant Appalachian Acreage Position

Western Development Area (WDA)

- Average gross production[1]: ~326 MMcf/d
- Large inventory of Marcellus & Utica locations economic at ~$2.00/Mcf
- Royalty free mineral ownership enhances well economics
- Highly contiguous nature drives cost and operational efficiencies

Eastern Development Area (EDA)

- Average gross production: ~311 MMcf/d
- Mostly leased (16-18% royalty) with no significant near-term lease expirations
- ~84 remaining Marcellus & Utica locations economic at ~$1.82/Mcf
- Additional Marcellus (Tioga Co.) & Geneseo (Lycoming Co.) potential



(1) Average EDA and WDA gross production, as well as WDA-CRV Utica production (see slide 20) and Covington/Tract 595 Production (see slide 24), is for the quarter ended March 31, 2019.

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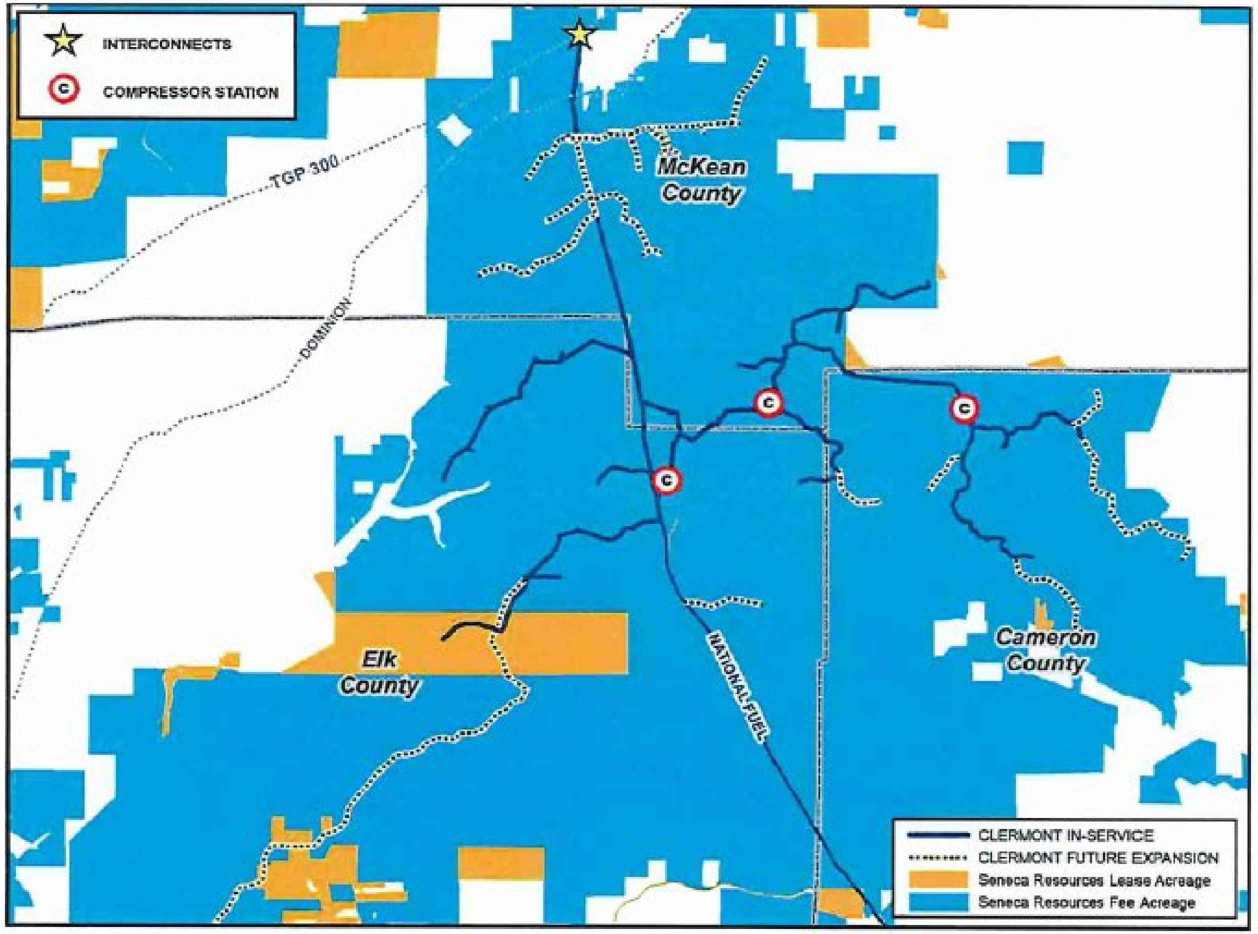
National Fuel

Integrated Development – WDA Gathering System

Gathering System Build-Out Tailored to Accommodate Seneca's WDA Development

Clermont Gathering System Map



Current System In-Service

- ~98 miles of pipe / 36,220 HP of compression
- Current Capacity: 470 MMcf per day
- Interconnects with TGP 300 and NFG Supply
- Total Investment to Date: $306 million

Future Build-Out

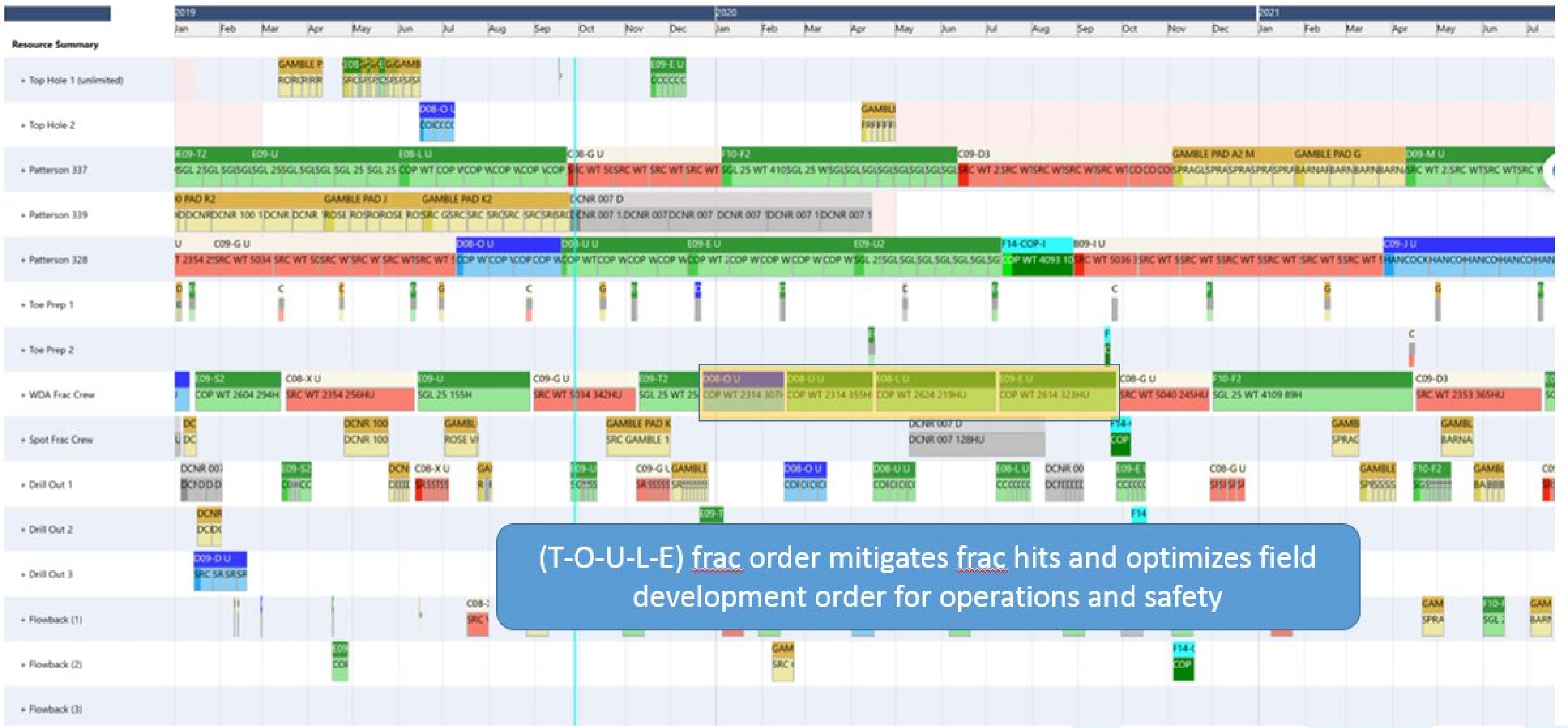
- FY 2019 CapEx: $9 - $12 million
- Modest gathering pipeline and compression investment required to support Seneca's Utica development
- Opportunity for 300 miles of pipelines and six compressor stations (+60,000 HP installed) as Seneca's drilling activity continues

Loading Causes – Prevention Part of the Cure

- Frac Hits
- High Line Pressures
- Operational Upsets - Compression
- Declining Reservoir Pressure
- High Water Cuts
- Long Laterals
- Full Life Cycle Challenges – 30 Years +

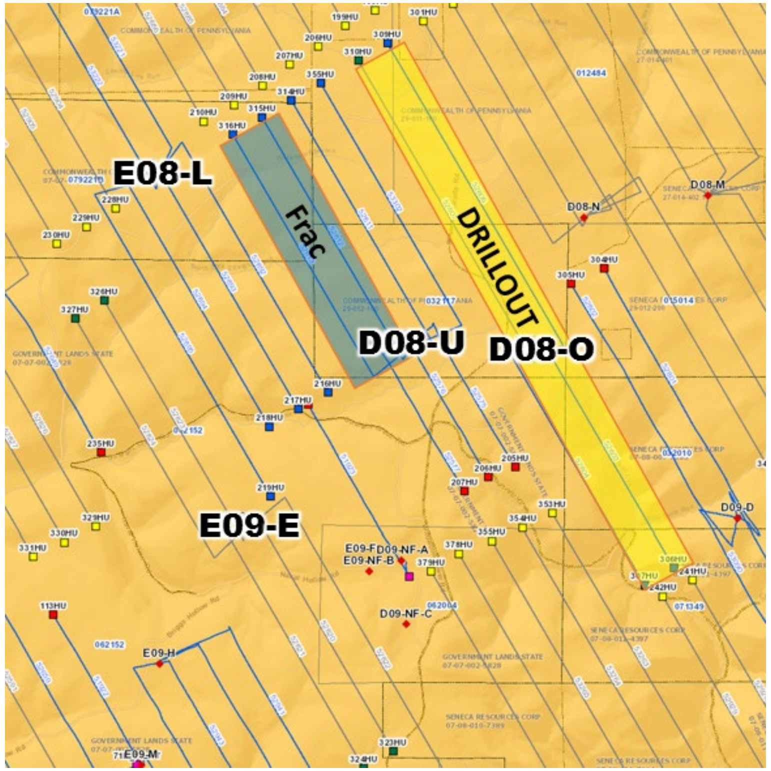
Minimize Frac Hits

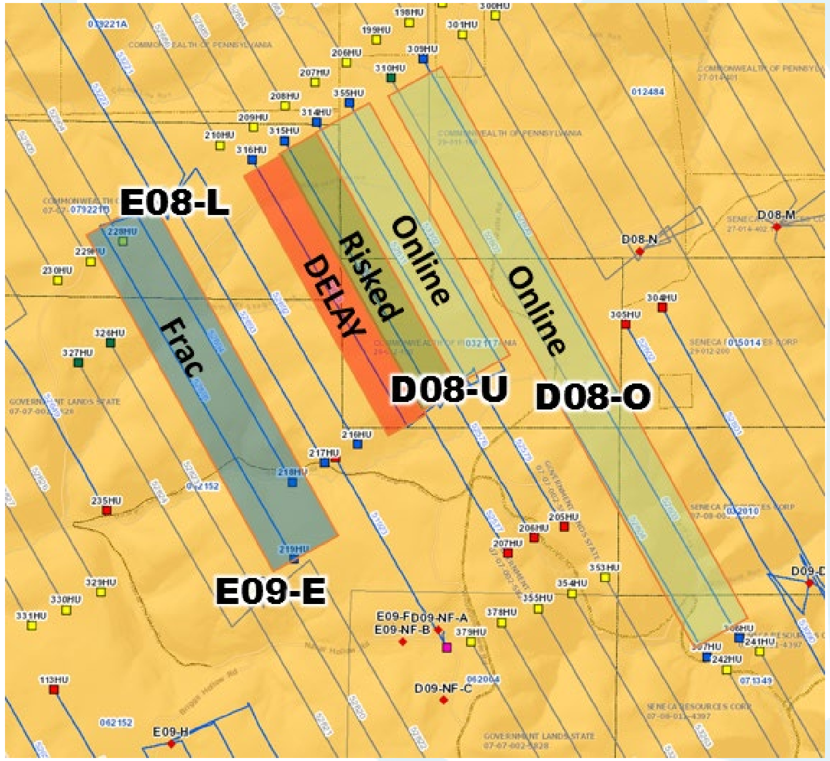
- Development Schedule



Minimize Frac Hits

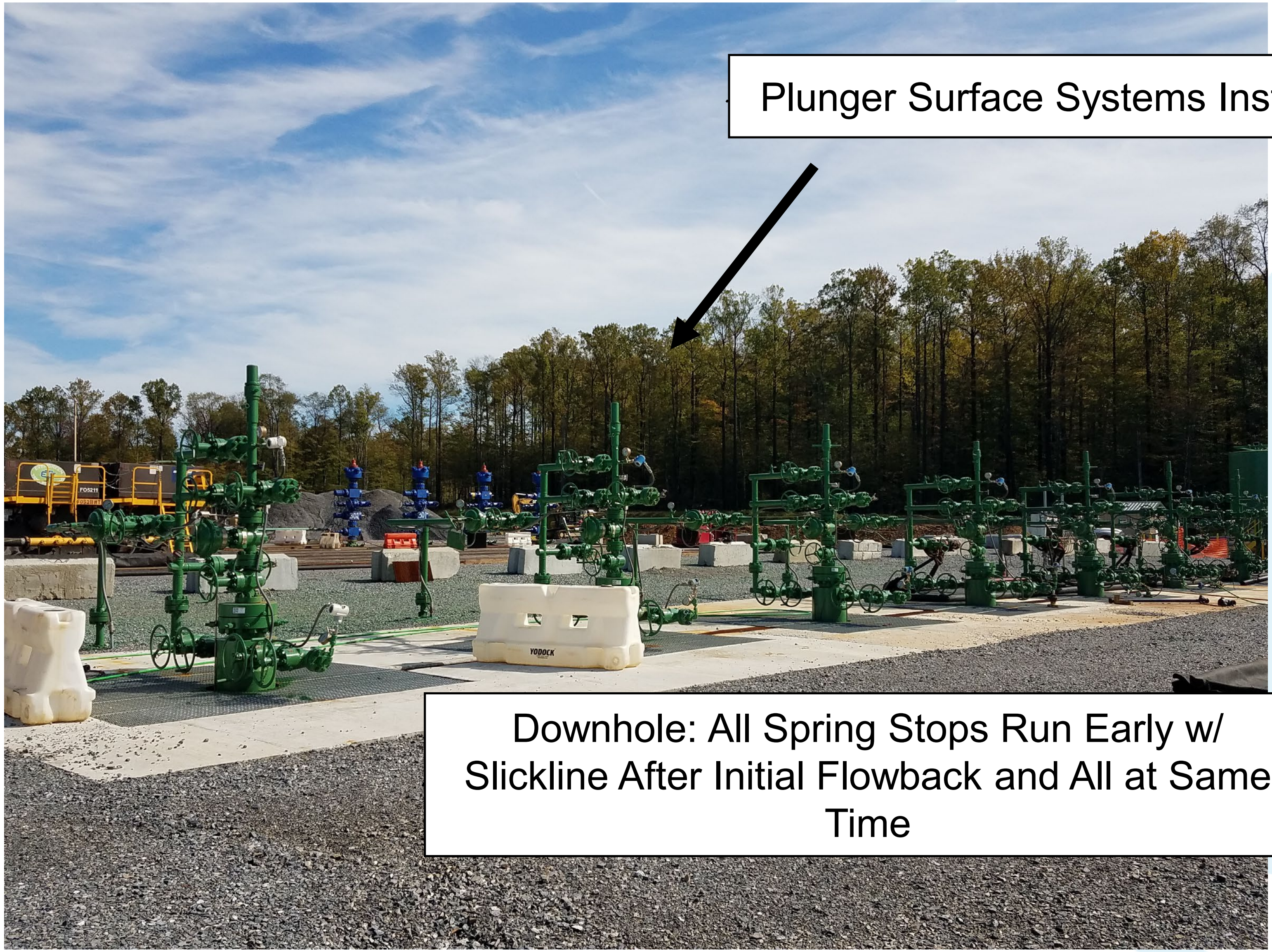
- Keep 2 well buffer between frac and drillout ops
  - Ops delayed based on this timing
- 1 well delay online until halfway through drillout of adjacent pad



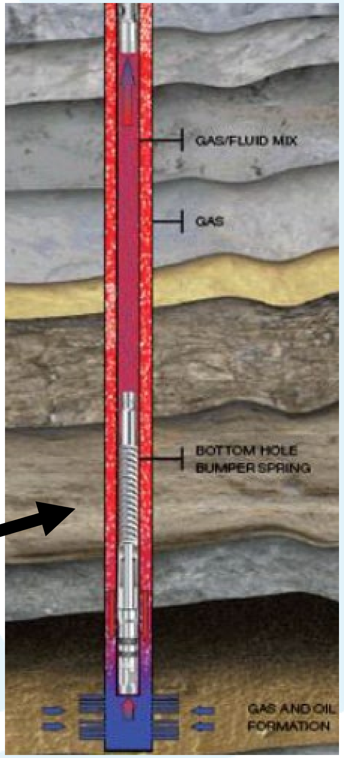


Typical Multi Well Pad – Proactive Plunger Installation

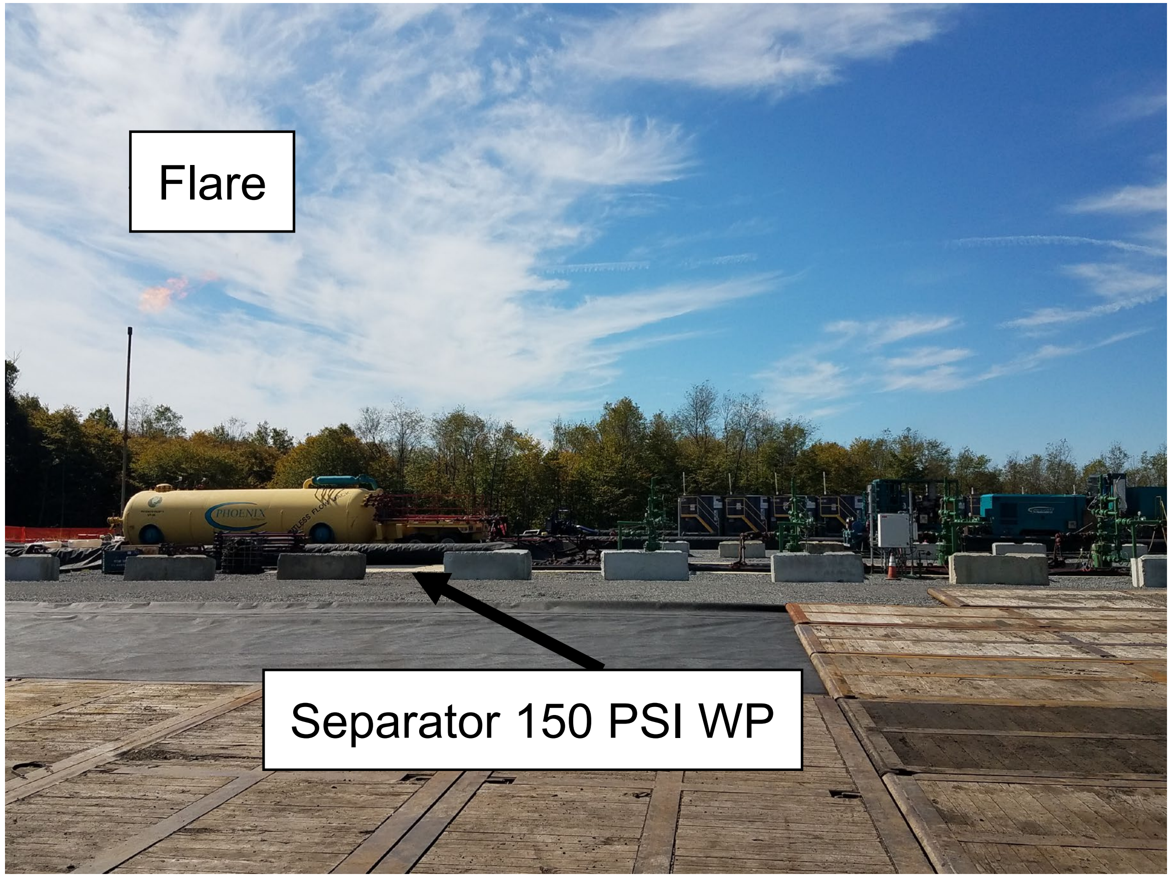
Plunger Surface Systems Installed With All Initial Wellheads

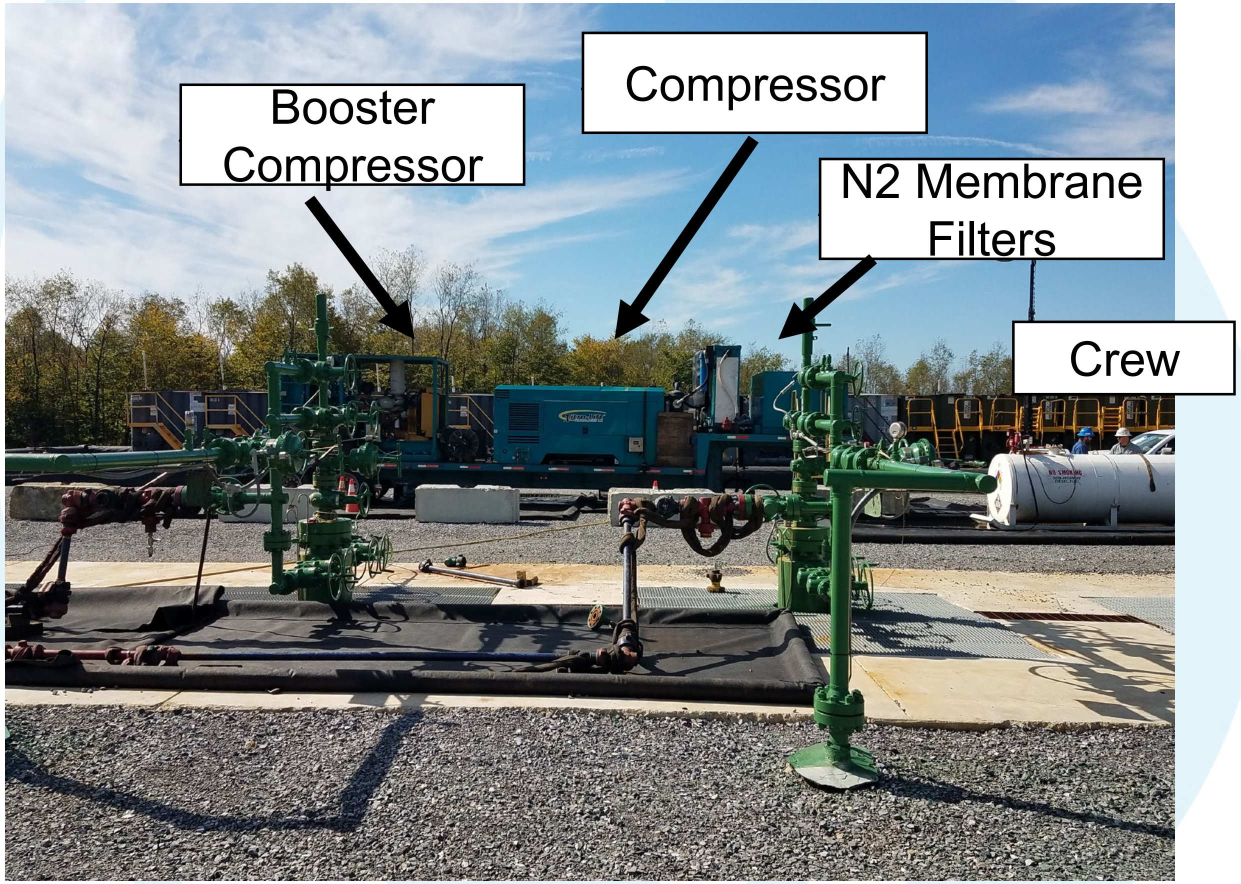


Downhole: All Spring Stops Run Early w/ Slickline After Initial Flowback and All at Same Time



Ventless N2 Membrane Unit - Unloading Frac Hit Wells





Multi- Well Capabilities

Measure – Measure - Measure

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Emerson has launched a new smaller version of its Roxar Multiphase Meter (MPFM) 2600. High Resolution Image

Emerson extends flow range and increases compactness of multiphase flow meter for effective well production, allocation and cost reductions in shale fields

STAVANGER, NORWAY (October 26, 2017) -- Emerson has launched a new smaller version of its industry-leading Roxar Multiphase Meter (MPFM) 2600 - a small size, cost-effective and modular flow meter specifically designed to address the flow profiles of North American shale fields and provide a meter suitable for the lifetime of the wells. Through switching from one separator per well to one Roxar multiphase meter per well, operators can reduce facilities capital investments at the well pad by over 50 percent, supporting Emerson's Project Certainty initiative as operators strive for Top Quartile Performance in capital efficiency in unconventional assets.

Other operator benefits include improved and more accurate well allocation; a reduced well pad footprint; and reduced environment exposure as tanks are pushed downstream to central facilities where they can be more efficiently monitored for regulatory and environment compliance, delivering operational excellence.

Coriolis Mass Flow Meter OMEGA™

Mass Flow, Density, Temperature and Volume Flow Meter

FMC-5000 Series

2 YEAR WARRANTY CE

- **15 to 150 mm (½ to 6") Sizes**
- **Mass Flow Rate, Volume, Density and Temperature Measurements**
- **Rugged Meters with No Moving Parts Results in Minimal Maintenance**
- **Accuracy Over a Wide Flow Range From a Single Meter Optimizes Plant Efficiency**
- **No Flow Conditioning or Straight Pipe Runs Required, Making Installation Simplified and Less Expensive**

The FMC-5000 Coriolis Mass Flow Meter is designed according to the Coriolis Force Principle. It is widely used for flow measurements and

FMC-5000 shown smaller than actual size.

ALRDC Resource & Recommended Practices

Guidelines & Recommended Practices
Selection of Artificial Lift Systems
for Deliquifying Gas Wells
P Prepared by Artificial Lift R&D Council

Status

- Document written and edited
- Chair: Cleon Dunham, cleon@oilfieldautomation.com
- Team: Not applicable
- Comments: Not applicable

2.0 General Guidelines for Artificial Lift Systems

This section addresses general information, tools, guidelines, and recommended practices for artificial lift in general and for each particular type of artificial lift system in particular.

Many different types of artificial lift are used to deliquify gas wells. Some are best used when liquid loading first occurs in a well. Some are better used later in the life of a well, when the initial method(s) may no longer work effectively. Some are best used near the end of the life of a well, when no other methods will work or are economical.

This section is intended as a brief tutorial on the types of artificial lift that are generally used for gas well deliquification. Personnel involved in artificial lift of gas wells must be fully conversant with this information.

Sub-sections contained in this section are:

2.1 Fundamentals of Gas Well Deliquification

This covers such topics as what is liquid loading, how does it inhibit gas production, when is some form of artificial lift required?

2.2 Pertinent Types of Artificial Lift

ALRDC – Know the “KNOWS” – Operational Excellence

Artificial Lift R & D Council (ALRDC)

Search for this Information:

ALRDC Organization

Upcoming Artificial Lift Workshops

- Feb. 2020 Artificial Lift Workshop
- Sep. 2019 Sucker Rod Workshop - Oklahoma City

Past Artificial Lift Workshops

- June 2019 Gas-Lift Worksop - Houston
- Feb. 2019 Art. Lift for Unconventional Wells
- Sept. 2018 Sucker Rod Workshop - Oklahoma City
- April 2018 Southwestern Petroleum Short Course
- Feb. 2018 Art. Lift for Unconventional Wells

ALRDC Sponsored R&D and JIP Projects

- Sponsored R&D and JIP Projects Home
- Univ. of Missouri Proposed Project
- HWDDDA R&D Project

Upcming ALRDC Seminars

- 2019 ALRDC Seminar for New Art. Lift Technology

Past ALRDC Seminars

- 2018 ALRDC Seminar for New Art. Lift Technology
- 2017 ALRDC Seminar for New Art. Lift Technology

ALRDC Links Updatded

- Dec. 30, 2017 --- Seeking Jobs, Jobs Available
- Feb. 20, 2017 --- ALRDC Award of Excellence
- Feb. 19, 2017 --- Interesting Articles
- Jan. 31, 2017 --- Artificial Lift Selection

1 Things that Must be Known to Create an Optimum Artificial Lift Selection Process

1.0 Final Introduction
1.1 Final Know Your Business
1.2 Final Know Your Company
1.3 Final Know Your Economics
1.4 Final Know Your Staff
1.5 Final Know Your Suppliers
1.6 Final Know Your Reservoirs
1.7 Final Know Your Wells
1.8 Final Know the Performance of Your Wells
1.9 Final Know Your Surface System

Plunger Lift – EPA Gas Star – Lessons Learned 2006

Exhibit 1: Plunger Lifts

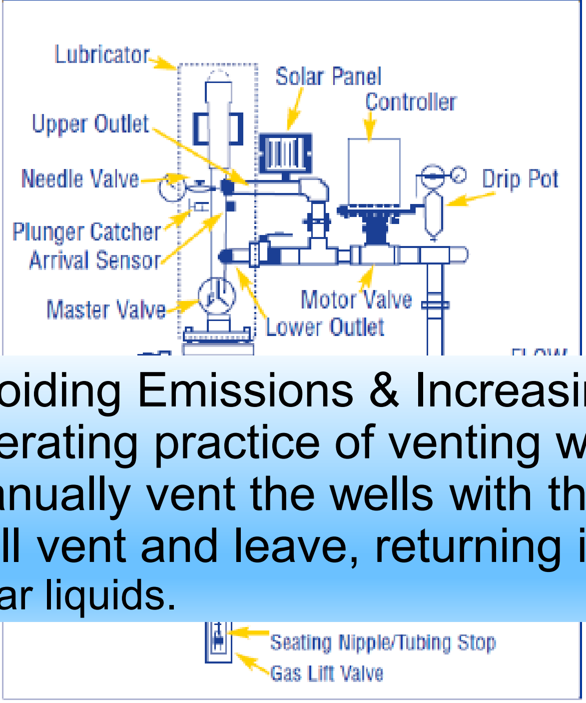

Exhibit 2: Common Requirements for Plunger Lift Applications

- ★ Well blowdowns and other fluid removal techniques are necessary to maintain production.
- ★ Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.
- ★ Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.
- ★ Wells with scale or paraffin buildup.

Lessons Learned
from Natural Gas STAR Partners

Installing Plunger Lift Systems In Gas Wells

Executive Summary

In mature gas wells, the accumulation of fluids in the well can impede and sometimes halt gas production. Gas flow is maintained by removing accumulated fluids through the use of a beam pump or remedial treatments, such as swabbing, soaping, or venting the well to atmospheric pressure (referred to as "blowing down" the well). Fluid removal operations, particularly well blowdowns, may

reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well by avoiding blowdowns. In addition, increased gas production following plunger lift installation has yielded total gas benefits of up to 18,250 Mcf per well, worth an estimated $127,750. Benefits from both increased gas production and emissions savings are well- and reservoir-specific and will vary considerably.

Technology Background

Liquid loading of the wellbore is often a serious problem in aging production wells. Operators commonly use beam lift pumps or remedial techniques, such as venting or "blowing down" the well to atmospheric pressure, to remove liquid buildup and restore well productivity. These techniques, however, result in gas losses. In the case of blowing down a well, the process must be repeated over time as fluids

buildup of pressure in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must be sufficiently higher than the sales-line pressure to lift the plunger and liquid load to the surface. A valve mechanism, controlled by a microprocessor, regulates gas input to the casing and automates the process. The controller is normally powered by a solar recharged battery and can be a simple timer-cycle or have solid state

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Potential Gas Savings from Increased Gas Production and Avoided Emissions (Mcf)	Value of Natural Gas Production and Savings ($)			Implementation Cost ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Install a Plunger Lift System	4,700 - 18,250[a] per year per well	$14,100 - $54,750 per year	$23,500 - $91,250 per year	$32,900 - $127,750 per year	$2,591 - $10,363 per year per well	1 - 9	1 - 6	1 - 4

General Assumptions:
[a] Based on results reported by Natural Gas STAR Partners.

- Avoiding Emissions & Increasing Revenue: The most important variable, however, is the normal operating practice of venting wells. Some operators put wells on automatic vent timers, while others manually vent the wells with the operator standing by monitoring the vent, and still others open the well vent and leave, returning in hours or up to days, depending on how long it typically takes the well to clear liquids.

Plunger Lift

Figure 3 shows a conventional plunger cycle:

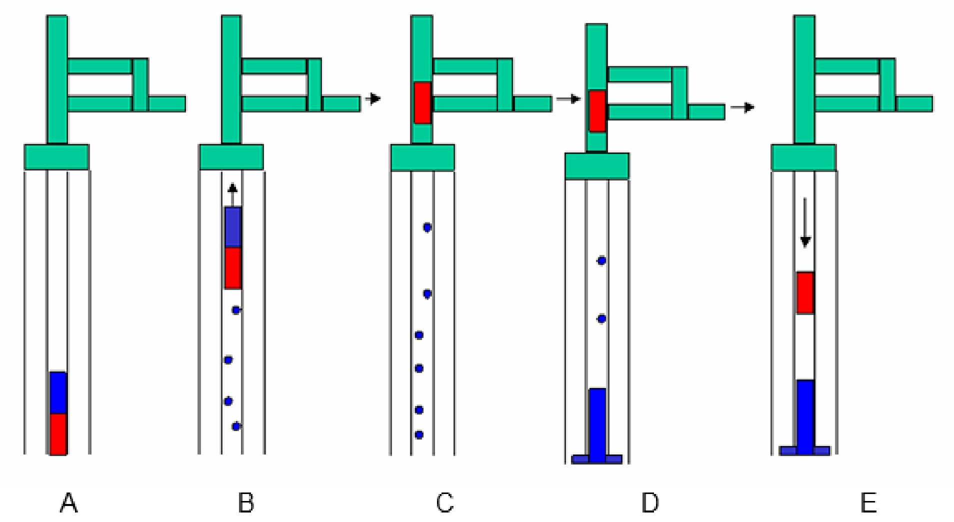

Figure 3: A conventional plunger cycle

A- Plunger at bottom with some liquid above plunger. Surface valve closed.
B- Surface valve opens and plunger rises with liquid above it.
C- Well flows at high rate for a while
D- Well begins to liquid load
E- Well shut in for plunger to fall through (1) gas and (2) liquid. A pressure build up period is controlled if needed.

Plungers used for this cycle include brush plungers, grooved plungers, wobble washer plungers, padded plungers, and other special types.

Figure 4 shows a free-cycle plunger cycle or continuous plunger cycle. It can be achieved by use of a two piece plunger as below or other contained ball and seat or contained valve type plungers.

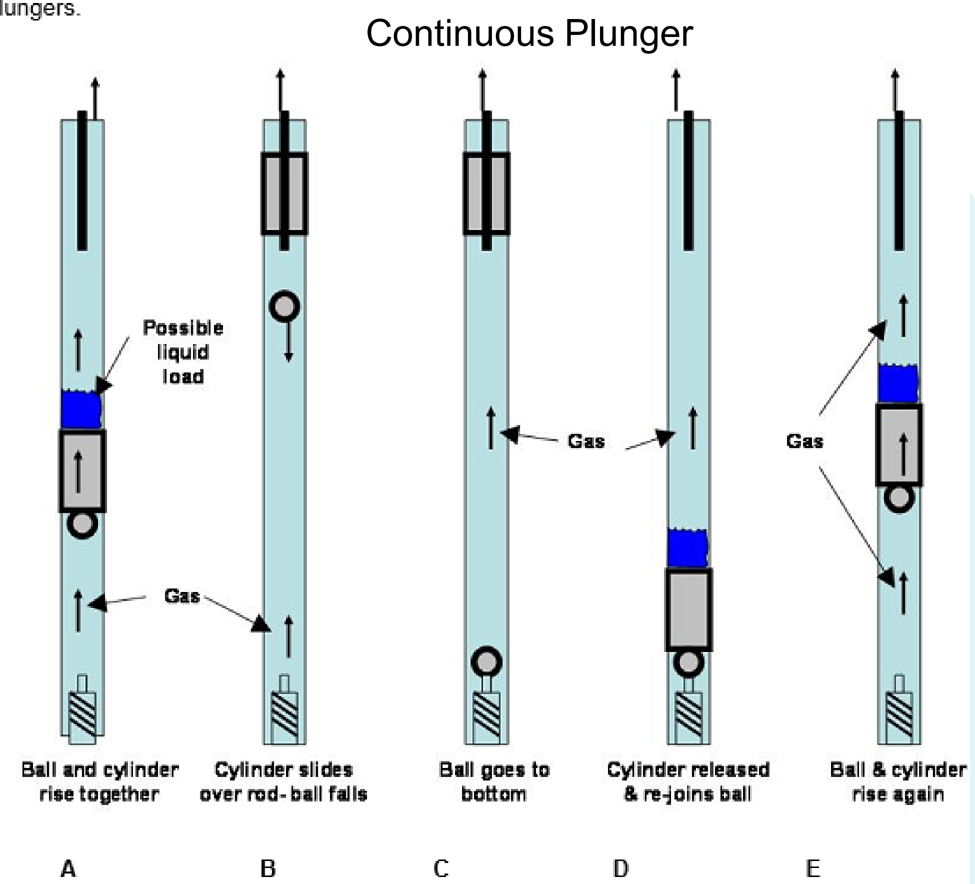

Figure 4: A "free cycle" or "continuous flow" plunger cycle operation.

This figure shows a two-piece plunger (sleeve and ball) but this cycle could also work with a valved plunger such as the Weatherford RapidFlo™ Plunger, the FB FreeCycle™ Plunger, the McClain™ Plunger, or as shown above, the Pacemaker™ (two-piece) plunger. Other plungers that are not mentioned here may also work on this cycle.

A- The plunger is sealed by the ball at the bottom of a sleeve or a valve is closed in the plunger. It is carrying up a slug of liquid with the surface valve open.
B- The plunger arrives at the surface. If the two-piece plunger is used, the sleeve is held on a receiving rod and the ball falls against the flow. If a valve-type plunger is used, the plunger is held on a receiving rod with the flow.

AL Requires Collaboration

Gas Well Deliquification Workshop

Sheraton Hotel, Denver, Colorado

February 23 – 26, 2014

Development of a Plunger Lift Playbook

Shane Myers & Kelli Poppenhagen

Encana

"At Encana, sustainability is exemplified in our efforts towards innovative and efficient business practices. The Environmental Partnership provides a forum for collaborating with industry partners on the use of technologies and best management practices to reduce emissions without dictating solutions. Encana's participation in **The Environmental Partnership demonstrates our commitment to reducing VOC emissions through innovation and deployment of efficient, sustainable business practices.**"

MICHAEL MCALLISTER
Executive Vice President & Chief Operating Officer
Encana Services Company Ltd.

Charter – Problem Statement

- Limited communication and uniformity company-wide regarding plunger lift operation
- Lacking consistent set of operating practices:
  - Encana currently operates ~5300 (36%) plunger lift wells and counting
  - 91% of surveyed prod ops personnel believe plunger operation is somewhat consistent to not at all consistent
- Successes and failures of formal and informal testing of tools, techniques and concepts are not always shared effectively

Best Management Practices

- Build momentum early
  - Build and involve focus group early and often
  - Start small and advertise achievements, especially initially
  - Meet regularly and often, especially at the onset
  - Continually solicit group feedback for improvements or ideas
- Keep it fun!
  - Face-to-face meetings, ice-breakers
- Use technology to bridge distance gap, i.e. SharePoint, video conference, and WebEx

CCAC Reference Document

CLIMATE & CLEAN AIR COALITION
TO REDUCE SHORT-LIVED CLIMATE POLLUTANTS

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> Solution centre > Resource Library

Technical Guidance Document Number 7: Well Venting For Liquids Unloading

Authors:
Climate and Clean Air Coalition (CCAC)

Resource type:
Guidelines & Tools

Publishing year:
2017

INITIATIVES

OIL AND GAS

POLLUTANTS (SLCP)

> Methane

CCAC Mitigation Table

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 operator has optimized the plunger lift operations such that vented emissions are substantially less than manual liquids unloading venting (Option C). Exhibit B	Mitigated
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

EPA Reference Document

Oil and Natural Gas Sector

Liquids Unloading Processes

Report for Oil and Natural Gas Sector
Liquids Unloading Processes
Review Panel
April 2014

Prepared by
U.S. EPA Office of Air Quality Planning and Standards (OAQPS)

This information is distributed solely for the purpose of pre-dissemination peer review under applicable information quality guidelines. It has not been formally disseminated by EPA. It does not represent and should not be construed to represent any Agency determination or policy.

4.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of VOC and methane emissions from liquids unloading and the emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding this source of VOC and methane emissions:

- A majority of gas wells (conventional and unconventional) must perform liquids unloading at some point during the well's lifetime. As gas wells age and well pressure declines, the need for liquids unloading to enhance well performance becomes more likely.
- The 2014 GHG Inventory estimates the 2012 liquids unloading emissions to be 14% of natural gas production sector emissions.
- The majority of emissions from liquids unloading events come from a small percentage of wells. Some of the characteristics that affect the magnitude of liquids unloading annual emissions from a well are the length of time of each event and the frequency of events.
- A wide range of emission rates from blowdowns have been reported from the limited available well-level data. In the Allen et. al. study, when emissions are averaged per event, emissions from four of the nine events included in the study contribute more than 95% of the total emissions. This result is consistent with the API/ANGA 2012 Survey data and 2012 data reported to the GHGRP; all suggest that certain wells produce more emissions during blowdowns than others. Some suggested causes of this variation are the length of the blowdown and the number of blowdowns per year, which are affected by underlying geologic factors.
- Industry has developed several technologies that effectively remove liquids from wells and can result in fewer emissions than blowdowns. Plunger lifts are the most common of those technologies.
- The emissions reduction efficiency plunger lifts can achieve varies greatly depending on how the system is operated. It is not clear to the EPA what the conditions are that lead to wells with plunger lifts to be vented during plunger lift operation.
- The two liquids unloading techniques that result in vented emissions that the EPA is aware of are plunger lifts when vented to the atmosphere and blowdowns.

Lower Line Pressure Example w/ Multiphase Compressor

How the multiphase compressor compares to other technologies

Technology	Multiphase Compressor	Reciprocating Piston / Axial	Rotary Screw Pump Multiphase
Typical Max Boost Ratio per Stage	40:1	4:1	~ 4:1
Multiphase Capability	YES	NO	YES
High Efficiency Dry Gas Capability	YES	YES	NO
Flexible operating envelope	YES	NO	NO

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Significant reduction in methane emissions through wellhead multiphase compression

Traditional Operations:

Compressor stations typically responsible for 43% of emissions across natural gas supply chain.[1]

Significant Reduction in Methane Emissions

[1] Joint Institute for Strategic Energy Analysis. "Estimating U.S. Methane Emissions from the Natural Gas Supply Chain: Approaches, Uncertainties, Current Estimates, and Future Studies". August 2015

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Simplified Manual Unloading

- Know Your Wells Behavior – Some Need Immediate Attention Others Benefit From Longer Shut Ins
- Open Well To Sales and Sell Head Gas
- Route Well To Tank and Manually Unload
- Monitor Pressures for Up to Three Hrs
- If Well Does Not Unload Shut In and Take Next Step
- Next Step May Include Soaping Down Tbg, Injecting Soap In Annulus, or Longer SI Times
- Attempt For 2-3 Times
- If Well Still Not Unloading Then Need Additional Energy
- Call in N2 Membrane Unit
- Unload Manually

API Environmental Partnership

Program Summary

TARGETING EMISSIONS THROUGH COLLABORATION, PROVEN METHODS, AND ADVANCED TECHNOLOGY

MISSION

To continuously **improve the industry's environmental performance by taking action, learning about best practices and technologies, and fostering collaboration** in order to responsibly develop our nation's essential natural gas and oil resources.

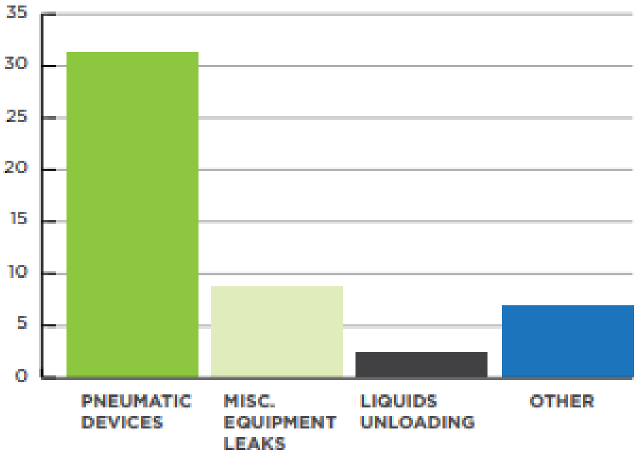
PRINCIPLES

Learn
Participants have committed to continuous learning about the latest industry innovations and best practices that can further reduce their environmental footprint while safely and responsibly growing energy production.

Collaborate
Participants have committed to collaborate with one another and with academics, researchers, and regulators, on the best strategies, tools, and tactics to improve environmental performance.

Take Action
Participants have committed to taking action to improve their environmental performance. This is being accomplished through The Partnership's three environmental performance programs, which companies can implement and phase into their operations.

EPA's GHGRP 2017 CH_4 Emissions (MMT CO_2E*)



*MMT CH_4 to MMT CO_2E using IPCC-AR5 GWP of 28
Source: *U.S. EPA Greenhouse Gas Reporting Program. Accessed April 29, 2019*

The Partnership is focused on reducing emissions from natural gas and oil production and is designed to evolve and advance, using innovations, science, and data to identify new initiatives to help the industry further reduce its environmental footprint, while safely and responsibly growing energy production.

- **Leak Detection and Repair:** *Participants committed to leak monitoring, followed by timely repair, at select sites using detection methods and technologies such as portable analyzers or optical gas imaging cameras.*
- **Focus on High-Bleed Pneumatic Controllers:** *Participants committed to replace, remove, or retrofit high-bleed pneumatic controllers with intermittent, low-, or zero-emitting devices.*
- **Improving the Manual Liquids Unloading Process:** *Participants committed to implement an industry best practice that minimizes emissions associated with the removal of liquids that, as a well ages, can build up and restrict natural gas flow.*

API Environmental Partnership

Implementation of Best Practices to Minimize Emissions During Removal of Liquids

Participants commit to monitoring the manual unloading process on-site or in close proximity and close all wellhead vents to the atmosphere as soon as practicable.

Program Specifics:

Emissions Source: Existing onshore gas well sites that conduct manual liquids unloading operations.

Method:

Operators will monitor the manual unloading process and close all wellhead vents to the atmosphere. This method will not apply to the following operations: swabbing, plunger lifts, or an episode where remaining on site might be considered a safety hazard.

Program Reporting and Content: The Environmental Partnership will report the number of monitored manual unloading procedures conducted on an annual basis.

- See link to API Environmental Partnership Annual Report.

https://www.api.org/~/media/Files/Policy/Environment/TEP/The-Environmental-Partnership-Annual-Report-2019.pdf

Conferences

The Environmental Partnership is a collaborative effort of the U.S. oil and natural gas industry. Its participants are working together in pursuit of improving environmental performance while responsibly developing our nation's essential oil and natural gas reserves.

The Environmental Partnership promotes information sharing to highlight individual company efforts and technology. In addition, The Environmental Partnership will host workshops and conferences to share ideas, learn from subject matter experts, and encourage improvement in operational practices and technologies.

Annual Conference 2018

The Environmental Partnership held its first annual conference on Wednesday, October 10th, 2018 in Denver, Colorado. Collaboration is one of the three pillars of the Environmental Partnership, and that was on full display at the conference which included 42 different organizations and companies.

Learn More

Collaboration With METEC

On Thursday, October 11th, 2018, participants in the Environmental Partnership had the opportunity to visit METEC, a research and testing facility located at Colorado State University. More than 20 members of the Partnership joined the tour.

- 2019 Conference In Houston

  23 & 24 Oct

Take Aways

- Minimize Frac Hits
- Manage Line Pressure – Consider Multi Line Systems,
- Manage Compression – Consider Multi Station Suction Pressure Options, Mulitphase Compression
- Plan for Inevitable Plunger Use – Surface & Downhole Equip.
- Activate AL Before Loading…eg. Continuous Plunger Lift, Soaping Systems, Gas Lift
- Measure, Measure, Measure
- Keep Your Flares Lit and Efficient
- Manually Unload Wells
- Keep Thief Hatches Closed
- Maintain ALL Tank Pressure Vacuum Relief Valves, Tank Vents, Arrestors, & Thief Hatches
- Challenge requires teamwork, use of collective experience, and knowledge sharing. Operational excellence.
- Know the “KNOWS”