Producer Best Management Practices

Lessons Learned from the Natural Gas STAR Program

EnCana Oil and Gas Inc.,
The Petroleum Association of Wyoming, and
The Independent Petroleum Association of Mountain States

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epa.gov/gasstar

Best Management Practices: Agenda

- Plunger Lifts and Smart Automation Well Venting
  - Methane Losses
  - Methane Savings
  - Is Recovery Profitable?
  - Industry Experience

- Compressors
  - Methane Losses
  - Methane Savings
  - Is Recovery Profitable?
  - Industry Experience

- Discussion
Methane Losses

- 395,000 natural gas and condensate wells (on and offshore) in the U.S.\(^1\)
- Blow-downs to unload fluids can vent 80 to 1,600 Mcf/year\(^2\) to the atmosphere per well
- 9 billion cubic feet (Bcf)/year from onshore well venting\(^1\)

\(\text{Pneumatic Devices} = 57 \text{ Bcf}\)
\(\text{Offshore Operations} = 34 \text{ Bcf}\)
\(\text{Dehydrators and Pumps} = 17 \text{ Bcf}\)
\(\text{Compressor Fugitives, Venting, and Engine Exhaust} = 14 \text{ Bcf}\)
\(\text{Well Venting and Flaring} = 9 \text{ Bcf}\)
\(\text{Meters and Pipeline Leaks} = 6 \text{ Bcf}\)
\(\text{Storage Tank Venting} = 9 \text{ Bcf}\)
\(\text{Other Sources} = 10 \text{ Bcf}\)
\(\text{Liquid Unloading Source: BP}\)

Accumulation of liquid hydrocarbons or water in the well bores reduces, and can halt, production

\(^1\) Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 - 2005
\(^2\) Mobil Big Piney Case Study 1997
Conventional Plunger Lift Operations

- Manual, on-site adjustments tune plunger cycle time to well’s parameters
  - Not performed regularly
  - Do not account for gathering line pressure fluctuations, declining well performance, plunger wear
- Results in manual venting to atmosphere when plunger lift is overloaded

Source: BP

What is the Problem?

- Conventional plunger lift systems use gas pressure buildups to repeatedly lift columns of fluid out of well
- Fixed timer cycles may not match reservoir performance
  - Cycle too frequently (high plunger velocity)
    - Plunger not fully loaded
  - Cycle too late (low plunger velocity)
    - Shut-in pressure can’t lift fluid to top
    - May have to vent to atmosphere to lift plunger

Source: Weatherford
Smart Automation Well Venting

- Automation can enhance the performance of plunger lifts by monitoring wellhead parameters such as:
  - Tubing and casing pressure
  - Flow rate
  - Plunger travel time
- Using this information, the system is able to optimize plunger operations
  - To minimize well venting to atmosphere
  - Recover more gas
  - Further reduce methane emissions

Methane Recovery: How Smart Automation Reduces Methane Emissions

- Smart automation continuously varies plunger cycles to match key reservoir performance indicators
  - Well flow rate
    - Measuring pressure
  - Successful plunger cycle
    - Measuring plunger travel time
- Plunger lift automation allows producer to vent well to atmosphere less frequently
Automated Controllers

- Low-voltage; solar recharged battery power
- Monitor well parameters
- Adjust plunger cycling

Remote well management
- Continuous data logging
- Remote data transmission
- Receive remote instructions
- Monitor other equipment

Plunger Lift Cycle

Well Blowdowns | Potential Incremental Production with Plunger Lift
---|---
1999 | 1000
2001 | 12000
2002 | 14000
2003 | 15000
2004 | 17000
2005 | 19000
2006 | 21000
2007 | 23000
2008 | 25000
2009 | 27000
2010 | 29000
2011 | 31000
2012 | 33000
2013 | 35000
2014 | 37000
2015 | 39000
2016 | 41000
2017 | 43000
2018 | 45000

Plunger Lifts Installed

Potential Continuous Production with Plunger Lifts

Production Control Services
Spiro Formation Well 9N-27E

Source: Weatherford
Methane Savings

- Methane emissions savings a secondary benefit
  - Optimized plunger cycling to remove liquids increases well production by 10 to 20%\(^1\)
  - Additional 10%\(^1\) production increase from avoided venting
- 500 Mcf/year methane emissions savings for average U.S. well

\(^1\) - Reported by Weatherford

Other Benefits

- Reduced manpower cost per well
- Continuously optimized production conditions
- Remotely identify potential unsafe operating conditions
- Monitor and log other well site equipment
  - Glycol dehydrator
  - Compressor
  - Stock Tank
  - Vapor Recovery Unit

Source: BP
Is Recovery Profitable?

- Smart automation controller installed cost: ~$11,000
- Conventional plunger lift timer: ~$5,000
- Personnel savings: double productivity
- Production increases: 10% to 20% increased production

Savings =

\[ (\text{Mcf/year}) \times (10\% \text{ increased production}) \times (\text{gas price}) + (\text{Mcf/year}) \times (1\% \text{ emissions savings}) \times (\text{gas price}) + (\text{personnel hours/year}) \times (0.5) \times (\text{labor rate}) \]

$ savings per year

Economic Analysis

- Non-discounted savings for average U.S. Well =

\[ (50,000 \text{ Mcf/year}) \times (10\% \text{ increased production}) \times ($7/\text{Mcf}) + (50,000 \text{ Mcf/year}) \times (1\% \text{ emissions savings}) \times ($7/\text{Mcf}) + (500 \text{ personnel hours/year}) \times (0.5) \times ($30/hr) - ($11,000) \text{ cost} \]

$35,000 savings in first year

3 month simple payback
BP Experience

- BP’s first automation project designed and funded in 2000
- Pilot installations and testing in 2000
  - Installed plunger lifts with automated control systems on ~2,200 wells
  - ~$15,000 per well Remote Terminal Unit (RTU) installment cost
  - $50,000 - $750,000 host system installment cost
- Achieved roughly 50% reduction in venting from 2000 to 2004

BP Experience

- BP designed two pilot studies in 2006 to further improve well scientific control
  - Interviewed control room staff and worked closely with the field automation team leader
  - Established a new procedure based on plunger lift expertise and pilot well analysis
- In mid 2006, “smarter” automation was applied to wells
  - 1,424 Mcf reported annual savings per well
BP Experience

Asset Vent Volume

Source: BP

BP Experience

Daily Vent Volumes

Source: BP
Compressors: Agenda

- Compressors
  - Methane Losses
  - Methane Savings
  - Is Recovery Profitable?
  - Industry Experience

Compressor Methane Emissions
What is the problem?

- Methane emissions from the ~51,500 compressors in the natural gas industry account for 89 Bcf/year or about 24% of all methane emissions from the natural gas industry.
Methane Losses from Reciprocating Compressors

- Reciprocating compressor rod packing leaks some gas by design
  - Newly installed packing may leak 60 cubic feet per hour (cf/hour)
  - Worn packing has been reported to leak up to 900 cf/hour

Reciprocating Compressor Rod Packing

- A series of flexible rings fit around the shaft to prevent leakage
- Leakage may still occur through nose gasket, between packing cups, around the rings, and between rings and shaft
Impediments to Proper Sealing

Ways packing case can leak
- Nose gasket (no crush)
- Packing to rod (surface finish)
- Packing to cup (lapped surface)
- Packing to packing (dirt/lube)
- Cup to cup (out of tolerance)

What makes packing leak?
- Dirt or foreign matter (trash)
- Worn rod (.0015”/per inch dia.)
- Insufficient/too much lubrication
- Packing cup out of tolerance ($\leq 0.002”$)
- Improper break-in on startup
- Liquids (dilutes oil)
- Incorrect packing installed (backward or wrong type/style)

Methane Losses from Rod Packing

| Emission from Running Compressor | 99 cf/hour-packing |
| Emission from Idle/Pressurized Compressor | 145 cf/hour-packing |

| Leakage from Idle Compressor Packing Cup | 79 cf/hour-packing |
| Leakage from Idle Compressor Distance Piece | 34 cf/hour-packing |

<table>
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<tr>
<th>Packing Type</th>
<th>Bronze</th>
<th>Bronze/Steel</th>
<th>Bronze/Teflon</th>
<th>Teflon</th>
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<tr>
<td>Leak Rate (cf/hour)</td>
<td>70</td>
<td>63</td>
<td>150</td>
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<tr>
<td>Leak Rate (cf/hour)</td>
<td>70</td>
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<td>147</td>
<td>22</td>
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</table>

PRCI/ GRI/ EPA. Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations
Steps to Determine Economic Replacement

- Measure rod packing leakage
  - When new packing installed – after worn-in
  - Periodically afterwards
- Determine cost of packing replacement
- Calculate economic leak reduction
- Replace packing when leak reduction expected will pay back cost

Cost of Rod Packing Replacement

- Assess costs of replacements
  - A set of rings: $135 to $1,080
    (with cups and case) $1,350 to $2,500
  - Rods: $2,430 to $13,500
  - Special coatings such as ceramic, tungsten carbide, or chromium can increase rod costs

Source: CECO
Calculate Economic Leak Reduction

Determine economic replacement threshold

- Partners can determine economic threshold for all replacements
- This is a capital recovery economic calculation

Economic Replacement Threshold (cf/hour) = \( \frac{CR \times DF \times 1,000}{(H \times GP)} \)

Where:
- \( CR \) = Cost of replacement ($)
- \( DF \) = Discount factor at interest \( i = \)
- \( H \) = Hours of compressor operation per year
- \( GP \) = Gas price ($/thousand cubic feet)

Economic Replacement Threshold

Example: Payback calculations for new rings and rod replacement

\( CR = $1,620 \) for rings + $9,450 for rod
\( H = 8,000 \) hours per year
\( GP = $7/Mcf \)

One year payback

\( ER = \frac{11,070 \times 1.1 \times 1,000}{(8,000 \times $7)} = 217 \text{ scf per hour} \)
Is Rod Packing Replacement Profitable?

- Replace packing when leak reduction expected will pay back cost

  - “leak reduction expected” is the difference between current leak rate and leak rate with new rings

<table>
<thead>
<tr>
<th>Leak Reduction Expected (cf/hour)</th>
<th>Payback (months)</th>
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<tbody>
<tr>
<td>Rings Only</td>
<td>Rod and Rings</td>
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<td>Rings: $1,620</td>
<td>Rings: $1,620</td>
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<td>Rod: $0</td>
<td>Rod: $9,450</td>
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<tr>
<td>Gas: $7/Mcf</td>
<td>Gas: $7/Mcf</td>
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<tr>
<td>Operating: 8,000 hours/year</td>
<td>Operating: 8,000 hours/year</td>
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<td>61</td>
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<td>32</td>
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</tbody>
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- Based on 10% interest rate

- Mcf = thousand cubic feet

Industry Experience – Northern Natural Gas

- Monitored emission at two locations
  - Unit A leakage as high as 301 liters/min (640 cf/hour)
  - Unit B leakage as high as 105 liters/min (220 cf/hour)

- Installed Low Emission Packing (LEP)
  - Testing is still in progress
  - After 3 months, leak rate shows zero leakage increase
Northern Natural Gas - Leakage Rates

Northern Natural Gas Packing Leakage Economic Replacement Point

- Approximate packing replacement cost is $3,000 per compressor rod (parts/labor)
- Assuming gas at $7/Mcf:
  1 cubic foot/minute = 28.3 liters/minute
  - 50 liters/minute/28.316 = 1.8 scf/minute
  - 1.8 x 60 minutes/hour = 108 scf/hr
  - 108 x 24/1000 = 2.6 Mcf/day
  - 2.6 x 365 days = 950 Mcf/year
  - 950 x $7/Mcf = $6,650 per year leakage
- This replacement pays back in <6 months
Low Emission Packing

- Low emission packing (LEP) overcomes low pressure to prevent leakage
- The side load eliminates clearance and maintains positive seal on cup face
- LEP is a static seal, not a dynamic seal. No pressure is required to activate the packing
- This design works in existing packing case with limited to no modifications required

LEP Packing Configuration
Orientation in Cup

Reasons to Use LEP

- Upgrade is inexpensive
- Significant reduction of greenhouse gas are major benefit
- Refining, petrochemical and air separation plants have used this design for many years to minimize fugitive emissions
- With gas at $7/Mcf, packing case leakage should be identified and fixed.
Discussion Questions

- To what extent are you implementing these opportunities?
- How could these opportunities be improved upon or altered for use in your operation?
- What are the barriers (technological, economic, lack of information, regulatory, focus, manpower, etc.) that are preventing you from implementing these practices?