Producers Best Management Practices and Opportunities

Lessons Learned from the Natural Gas STAR Program

Anadarko Petroleum Corporation and the Domestic Petroleum Council

Producers Technology Transfer Workshop
College Station, Texas
May 17, 2007

epa.gov/gasstar
Agenda

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

- There are 395,000 natural gas and condensate wells (on and offshore) in the U.S.¹
- Accumulation of liquid hydrocarbons or water in the well bores reduces, and can halt, production
- Common “blow down” practices to restore production can vent 80 to 1,600 thousand cubic feet per year (Mcf/year)² to the atmosphere per well
- Estimated 9 billion cubic feet per year (Bcf/year) methane emissions from U.S. onshore well venting¹

² – Mobil. *Big Piney Case Study 1997*. 
Methane Recovery: Plunger Lifts

- Fluids can impede or halt gas production in mature wells
- Plunger lifts remove liquids
  - Well is shut-in
  - Well pressure builds up under plunger
  - Pushes it to surface, collecting liquids
- Benefits include
  - Continuous production
  - Lower maintenance
  - Increased efficiency
  - Reduced methane emissions
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
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
Methane Recovery: Smart Automation Well Venting

- Automation can further 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 optimizes 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

Source: Weatherford
Plunger Lift Cycle

Production Control Services
Spiro Formation Well 9N-27E

Well Production without Plunger Lift
Potential Continuous Production with Plunger Lifts

Well Blowdowns
Potential Incremental Production with Plunger Lift

TIME

Mcf/Month

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

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\(^1\) 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 (VRU)
Is Recovery Profitable?

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

Savings =

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

$ savings per year
**Economic Analysis**

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

  \[(50,000 \text{ Mcf/year}) \times (10\% \text{ increased production}) \times ($7/\text{Mcf}) \]

  + \[(50,000 \text{ Mcf/year}) \times (1\% \text{ emissions savings}) \times ($7/\text{Mcf}) \]

  + \[(500 \text{ personnel hours/year}) \times (0.5) \times ($40/\text{hour}) \]

  - ($11,000) cost

  $37,500 savings in first year

  3 month simple payback
Industry Experience

- BP reported installing plunger lifts with automated control systems on about 2,200 wells
  - 800 Mcf reported annual savings per well
  - $12 million costs including equipment and labor
  - $6 million total annual savings

- Another company shut in mountaintop wells inaccessible during winter
  - Installed automated controls allowed continuous production throughout the year

Vapor Recovery Units Agenda

- Vapor Recovery Units
  - Methane Losses
  - Methane Recovery
  - Is Recovery Profitable?
  - Industry Experience
Methane Losses

- **Flashing losses**
  - Occur when crude is transferred from a gas-oil separator at higher pressure to a storage tank at atmospheric pressure

- **Working losses**
  - Occur when crude levels change and when crude in tank is agitated

- **Standing losses**
  - Occur with daily and seasonal temperature and barometric pressure changes

- **Combine for 6 Bcf/year emissions**

Methane Recovery: Vapor Recovery

- Vapor recovery can capture up to 95% of hydrocarbon vapors from tanks
- Recovered vapors have higher heat content than pipeline quality natural gas
- Recovered vapors are more valuable than natural gas and have multiple uses
  - Re-inject into sales pipeline
  - Use as on-site fuel
  - Send to processing plants for recovering valuable natural gas liquids
Types of Vapor Recovery Units

- Conventional vapor recovery units (VRUs)
  - Use rotary compressor to suck vapors out of atmospheric pressure storage tanks
  - Require electrical power or engine driver

- Venturi ejector vapor recovery units (EVRU™) and Vapor Jet
  - Use Venturi jet ejectors in place of rotary compressors
  - Contain no moving parts
  - EVRU™ requires source of high pressure gas and intermediate pressure system
  - Vapor Jet requires high pressure water motive
Venturi Jet Ejector*

High-Pressure Motive Gas (about 850 psig)

Low-Pressure Vent Gas from Tanks (0.10 to 0.30 psig)

Discharge Gas (about 40 psia)

Suction Pressure (-0.05 to 0 psig)

*EVRU™ patented by COMM Engineering

Adapted from SRI/USEPA-GHG-VR-19

psig = pound per square inch, gauge

psia = pounds per square inch, atmospheric
Vapor Recovery with Ejector

5,000 Mcf/day gas
5,000 barrels/day Oil

Oil & Gas Well

LP Separator

Compressor

Gas to Sales @ 1000 psig

281 Mcf/day net recovery

300 Mcf/day gas

(19 Mcf/day incremental fuel)

Ejector

Ratio Motive / Vent = 3
= 900/300

6,200 Mcf/day

900 Mcf/day

Crude Oil Stock Tank

Oil to Sales

Oil
Vapor Jet System*

*Patented by Hy-Bon Engineering
Vapor Jet System*

- Utilizes produced water in closed loop system to effect gas gathering from tanks
- Small centrifugal pump forces water into Venturi jet, creating vacuum effect
- Limited to gas volumes of 77 Mcf / day and discharge pressure of 40 psig

*Patented by Hy-Bon Engineering
Criteria for Vapor Recovery Unit Locations

- Steady source and sufficient quantity of losses
  - Crude oil stock tank
  - Flash tank, heater/treater, water skimmer vents
  - Gas pneumatic controllers and pumps
- Outlet for recovered gas
  - Access to low pressure gas pipeline, compressor suction, or on-site fuel system
- Tank batteries not already subject to air regulations
Quantify Volume of Losses

- Estimate losses from chart based on oil characteristics, pressure, and temperature at each location (± 50%)
- Estimate emissions using the E&P Tank Model (± 20%)
- Engineering equations – Vasquez-Beggs (± 20%)
- Measure losses using recording manometer and well tester or ultrasonic meter over several cycles (± 5%)

This is the best approach for facility design
Estimated Volume of Tank Vapors

Vapor Vented from Tanks, cubic foot / barrel

Gas/Oil Ratio

Pressure of Vessel Dumping to Tank (Psig)

API Gravities

40° API and Over
30° API to 39° API
Under 30° API

°API = API gravity
**Vasquez-Beggs Calculation**

Atmospheric tanks may emit large amounts of tank vapors at relatively low separator pressure.

**Vasquez-Beggs Equation**

\[ \text{GOR} = A \times (G_{\text{flash \ gas}}) \times (P_{\text{sep}} + 14.7)^B \times \exp \left( \frac{C \times G_{\text{oil}}}{T_{\text{sep}} + 460} \right) \]

where,

- \( \text{GOR} \) = Ratio of flash gas production to standard stock tank barrels of oil produced, in scf/bbl oil (barrels of oil corrected to 60°F)
- \( G_{\text{flash \ gas}} \) = Specific gravity of the tank flash gas, where \( \text{API} = 1 \). A suggested default value for \( G_{\text{flash \ gas}} \) is 1.22 (INRCC; Vasquez, 1980)
- \( G_{\text{oil}} \) = API gravity of stock tank oil at 60°F
- \( P_{\text{sep}} \) = Pressure in separator, in psig
- \( T_{\text{sep}} \) = Temperature in separator, °F

For \( G_{\text{oil}} \leq 30^\circ \text{API} \): \( A = 0.0362 \); \( B = 1.0937 \); and \( C = 25.724 \)

For \( G_{\text{oil}} > 30^\circ \text{API} \): \( A = 0.0178 \); \( B = 1.187 \); and \( C = 23.931 \)

**Example for WTI Crude**

- \( G_{\text{oil}} = 40^\circ \text{API} \)
- \( G_{\text{flash \ gas}} = 1.22 \)
- \( T_{\text{sep}} = 100^\circ \text{F} \)
- \( P_{\text{sep}} = 3 \text{ psig} \)
- \( \text{GOR} = 3.6 \text{ scf/bbl} \)

psig – pounds per square inch, gauge
scf – standard cubic feet
bbl – barrels
Is Recovery Profitable?

<table>
<thead>
<tr>
<th>Peak Capacity (Mcf / day)</th>
<th>Installation &amp; Capital Costs¹ ($ / year)</th>
<th>O &amp; M Costs ($ / year)</th>
<th>Value of Gas² ($ / year)</th>
<th>Annual Savings</th>
<th>Simple Payback (months)</th>
<th>Return on Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td>25</td>
<td>26,470</td>
<td>5,250</td>
<td>$ 51,465</td>
<td>$ 46,215</td>
<td>7</td>
<td>175%</td>
</tr>
<tr>
<td>50</td>
<td>34,125</td>
<td>6,000</td>
<td>$ 102,930</td>
<td>$ 96,930</td>
<td>5</td>
<td>284%</td>
</tr>
<tr>
<td>100</td>
<td>41,125</td>
<td>7,200</td>
<td>$ 205,860</td>
<td>$ 198,660</td>
<td>3</td>
<td>483%</td>
</tr>
<tr>
<td>200</td>
<td>55,125</td>
<td>8,400</td>
<td>$ 411,720</td>
<td>$ 403,320</td>
<td>2</td>
<td>732%</td>
</tr>
<tr>
<td>500</td>
<td>77,000</td>
<td>12,000</td>
<td>$ 1,029,300</td>
<td>$ 1,017,300</td>
<td>1</td>
<td>1321%</td>
</tr>
</tbody>
</table>

¹ Unit Cost plus estimated installation at 75% of unit cost
² $11.28 x 1/2 capacity x 365, Assumed price includes Btu enriched gas (1.289 MMBtu/Mcf)

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**Vapor Composition**

<table>
<thead>
<tr>
<th>Mixture (MMBtu/Mcf)</th>
<th>Value ($/Mcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane 1.012</td>
<td>$ 7.22</td>
</tr>
<tr>
<td>Ethane 1.773</td>
<td>$ 16.18</td>
</tr>
<tr>
<td>Propane 2.524</td>
<td>$ 27.44</td>
</tr>
<tr>
<td>n Butane 3.271</td>
<td>$ 43.16</td>
</tr>
<tr>
<td>iso Butane 3.261</td>
<td>$ 46.29</td>
</tr>
<tr>
<td>Pentanes+ 4.380</td>
<td>$ 59.70</td>
</tr>
</tbody>
</table>

| Total               | 1.289         |
|                     | $ 11.28       |
Industry Experience: EVRU™

Facility Information
- Oil production: 5,000 Barrels/day, 30° API
- Gas production: 5,000 Mcf/day, 1060 Btu/cf
- Separator: 50 psig, 100° F
- Storage tanks: Four 1500 barrel tanks @1.5 ounces relief
- Measured tank vent: 300 Mcf/day @ 1,850 Btu/cf

EVRU™ Installation Information
- Motive gas required: 900 Mcf/day
- Gas sales: 5,638 MMBtu/day
- Reported gas value: $28,190/day @ $5/MMBtu
- Income increase: $2,545/day = $76,350/month
- Reported EVRU™ cost: $75,000
- Payout: <1 month
Discussion

- Industry experience applying these technologies and practices
- Limitations on application of these technologies and practices
- Actual costs and benefits