Methane to Markets

Reduced Emission Completions / Plunger Lift and Smart Automation

Oil & Gas Subcommittee Technology Transfer Workshop

January 28, 2009
Monterrey, Mexico
Well Venting Agenda

- Methane Losses
- Methane Recovery
- Is Recovery Profitable?
- Industry Experience
- Discussion

Source: Williams
Methane Losses (U.S.): Gas Well Completions and Workovers

- An estimated 45 Billion cf of natural gas lost annually due to well completions and workovers\(^1\)
- An estimated total of 480,000 Bbl condensate lost annually due to venting and flaring

\(^1\)Percentage that is flared and vented is not known
Methane Loss During Gas Well Completions

- It is necessary to clean out the well bore and formation following hydraulic fracturing
  - After new well completion
  - After well workovers

- Produce the well to an open pit or tank to collect sand, cuttings and reservoir fluids for disposal

- Vent or flare the natural gas produced
  - Venting may lead to dangerous gas buildup
  - Flaring is preferred where no fire hazard or nuisance
Methane Recovery by Reduced Emission Completions

- Recover natural gas and condensate produced during flow-back following hydraulic fracture
- Portable equipment separate sand and water, processes gas and condensate for sales
- Direct recovered gas through permanent dehydrator and meter to sales line, reducing venting and flaring
Reduced Emission Completions: Equipment

- Truck or trailer mounted equipment to capture produced gas during cleanup
  - Sand trap
  - Three-phase separator
- Use portable desiccant dehydrator for workovers requiring glycol dehydrator maintenance
Reduced Emission Completions: Preconditions

- Permanent equipment required on site before cleanup
  - Piping to well head
  - Dehydrator
  - Lease meter
  - Stock tank
- Sales line gas can be used for energy and/or gas lift in low pressure wells
Reduced Emission Completions: Low Pressure Wells

- Use portable compressors when pressure in well is low
  - Artificial gas lift to clear fluids
  - Boost gas to sales line
  - Higher cost to amortize investment
Reduced Emission Completions: Benefits

- Reduced methane emissions during completions and workovers
- Sales revenue from recovered gas and condensate
- Improved relations with government agencies and public neighbors
- Improved safety
- Reduced disposal costs
Is Recovery Profitable?

- Partners report recovering 2% - 89% (average of 53%) of total gas produced during well completions and workovers.

- Estimate 7 – 12,500 Mcf (average of 3,000 Mcf) of natural gas can be recovered from each cleanup.

- Estimate 1- 580 Bbl of condensate can be recovered from each cleanup.

Note: Values for high pressure wells.
Anadarko Experience

- Produces gas from “tight” formations in Wyoming, Colorado, and Utah
- 1998 to 2005 implemented conventional completions
  - 421 wells/year completed average
  - 2,072 MMcf/year lost average
  - 12 days venting/completion average
- Lost US$ 82.9 million\(^1\) of gas in 8 years
  - US$10.4 million/year average

\(^1\) Gas valued at US$5/Mcf
Anadarko Experience

- In 2006 started implementing RECs
- 2006 to 2008 RECs:
  - 613 wells/year completed
  - Net savings: 2,052 MMcf/year
    - Despite 45% increase in well completions
  - Less than 2 hours venting/completion on average
- US$10.3 million/year\(^2\) increased revenue

\(^1\) Gas valued at US$5/Mcf
Devon Energy Experience

- Implemented Reduced Emission Completion (REC) in the Fort Worth Basin
- REC performed on 30 wells at an average incremental cost of US$ 8,700
- Average 11,900 Mcf of natural gas sold vs. vented per well
  - Natural gas flow and sales occur 9 days out of 2 to 3 weeks of well completion
  - Low pressure gas sent to gas plant
  - Conservative net value of gas sold is US$ 59,500 per well at Mexico gas price\(^1\)
- Expected emission reductions of 1.5 to 2 Bcf per year moving forward

\(^1\) Gas valued at US$5/Mcf
Williams Experience

- Implemented 1,064 completions with flowback from 2002 through 2006
- Total implementation cost: US$17.41 million
- Recovered a total of 23,700 MMcf (23,700 BBtu\(^1\))
  - Equal to 91.1% recovery
  - Worth US$118.5 million at Mexico gas value\(^2\)

---

\(^1\) Assumes 1 Mcf = 1 MMBtu
\(^2\) Gas valued at US$5/MMBtu
Discussion Questions

- To what extent are you implementing this opportunity?
- Can you suggest other approaches for reducing well venting?
- 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 this practice?
Liquid Unloading

- Accumulation of liquid hydrocarbons or water in the well tubing reduces, and can halt, production
- Operators blow wells to atmosphere to expel liquids

Source: BP
Plunger lift recovers liquids with less gas venting

- 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
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

Plunger Lifts Installed
What is the problem?

- Fixed timer requires manual adjustments of the plunger cycle time
  - 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
Smart Automation Well Venting

- Automation can enhance the performance of plunger lifts by monitoring wellhead parameters
  - Tubing and casing pressure
  - Sales line 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
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
Methane Savings

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

\(^1\) Reported by Weatherford

Source: BP
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: ~US$15,000
  - Conventional plunger lift timer: ~US$7,000
- Personnel savings: double productivity
- Production increases: 10% to 20% increased production
- Production increase from avoided venting: 1%

\[
\text{Savings} = (\text{MMBtu/year}) \times (10\% \text{ increased prod.}) \times \text{(gas price)} \\
+ (\text{MMBtu/year}) \times (1\% \text{ emissions savings}) \times \text{(gas price)} \\
+ (\text{personnel hours/year}) \times (0.5) \times \text{(labor rate)}
\]

$ \text{savings per year}$
Economic Analysis

- Non-discounted savings for average well =
  (50,000 MMBtu/year) x (10% incr. prod.) x (US$5/MMBtu)
+ (50,000 MMBtu/year) x (1% emissions savings) x (US$5/MMBtu)

US$27,500 savings / year

- 6.6 months simple payback at US$ 5/MMBtu

<table>
<thead>
<tr>
<th>Gas Price (US$/MMBtu)</th>
<th>3</th>
<th>5</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Payback (months)</td>
<td>12.3</td>
<td>8.1</td>
<td>6.1</td>
</tr>
<tr>
<td>NPV (US$)</td>
<td>50,077</td>
<td>86,955</td>
<td>123,833</td>
</tr>
</tbody>
</table>
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
  - ~US$15,000 per well Remote Terminal Unit (RTU) installment cost
  - US$50,000 - US$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
  - Total of 3.1 Bcf/year savings (3,100 Bbtu/year)
  - Worth US$15.5 million/year\(^1\)

\(^1\) Gas valued at US$5/MMBtu
BP Experience

Asset Vent Volume

Production (Mscf/d)

Sales Volume
Line Press ('10)
Vent Mscf/d

5% of Production

Jan 2006
Mar 2006
May 2006
Jul 2006
Sep 2006

220,000
230,000
240,000
250,000
260,000
270,000
280,000
290,000
300,000

14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
BP Experience

Daily Vent Volumes

Vent Rate (Mscf/d)

2001 2002 2003 2004 2005 2006 2007
Discussion

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