Methane to Markets

Reduced Emission Completions / Plunger Lift and Smart Automation

IAPG & US EPA Technology Transfer Workshop

November 5, 2008
Buenos Aires, Argentina
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 1,27 Bm³ of natural gas lost annually due to well completions and workovers¹
- An estimated total of 480,000 Bbl condensate lost annually due to venting and flaring

¹Percentage 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 tankage 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

Temporary, Mobile Surface Facilities, Source: BP
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

![Image of portable compressor](JERRY_MCBRIDE_Herald)
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 0.2 – 354 Mm$^3$ (average of 85 Mm$^3$) 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
  - 59 MMm³/year lost average
  - 12 days venting/completion average
- Lost US$33.2 million\(^1\) of gas in 8 years
  - US$4.1 million/year average

\(^1\) Gas valued at US$70.63/MMm³
Anadarko Experience

- In 2006 started implementing RECs
- 2006 to 2008 RECs:
  - 613 wells/year completed
  - Net savings: 58 MMm$^3$/year
    - Despite 45% increase in well completions
  - Less than 2 hours venting/completion on average
- $4.1$ million/year$^1$ increased revenue

$^1$ Gas valued at US$70.63/Mm$^3$
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 337 MMm³ 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$23,800 per well at Argentina gas price¹
- Expected emission reductions of 43 to 57 MMm³ per year moving forward

¹ Gas valued at US$70,63/MMm³
Williams Experience

- Implemented 1.064 completions with flowback from 2002 through 2006
- Total implementation cost: US$17.41 million
- Recovered a total of 671 MMm³
  - Equal to 91.1% recovery
  - Worth US$47.4 million at Argentina gas value¹

¹ Gas valued at US$70.63/Mm³
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 expell 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
Potential Continuous
without Plunger Lift
Production with Plunger Lifts

Plunger Lifts Installed

Well Blowdowns
Potential Incremental Production with Plunger Lift
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

14 Mm\(^3\)/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%

Savings =
\[
\text{(Mm}^3/\text{year}) \times (10\% \text{ increased prod.}) \times (\text{gas price}) + \text{(Mm}^3/\text{year}) \times (1\% \text{ emissions savings}) \times (\text{gas price}) + \text{(personnel hours/year}) \times (0.5) \times (\text{labor rate})
\]

$ savings per year
Economic Analysis

- Non-discounted savings for average well =

\[(1.416 \text{ Mm}^3/\text{year}) \times (10\% \text{ incr. prod.}) \times (\text{US}\$70,63/\text{Mm}^3)\] 
\[+ (1.416 \text{ Mm}^3/\text{year}) \times (1\% \text{ emissions savings}) \times (\text{US}\$70,63/\text{Mm}^3)\]

US\$11,000 savings / year

- 16.5 months simple payback at Argentina gas price
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
  - 40 Mm$^3$ reported annual savings per well
  - Total of 88 MMm$^3$/year savings
  - Worth US$6,2 million/year
BP Experience

Daily Vent Volumes

2001 2002 2003 2004 2005 2006 2007

0 2,000 10,000 12,000
Discussion

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