A Longer Lasting Flowing Gas Well

New Dual-Tubing Flowing Design

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Purpose of This Presentation

- To share a new flowing gas well design and associated data
- To invite interested minds to build upon the technology
Gas / Liquid Flow Regimes
(This presentation focuses on Mist Flow)

Mist Flow

Slug Flow

Liquid with gas bubbles
Options To Unload Well
(This presentation focuses on ‘Fit for purpose tubing size’)

Soap Injection
1/4” capillary tubing

Plunger Lift

Fit for purpose tubing size
Dual Tubing Wellbore Diagrams

Conventional, Two Formation Dual

New, Single Formation Dual
Wellhead and Tree

Single Tubing String

Conventional Dual (2 Formations)

New Dual (1 Formation)
Why This New Dual?

- Economics
- To reduce long term operating cost
- To provide efficient flow over a wide range of gas rates
BP Current Dual Status, San Juan Basin

- 11 installations to date
  - 5 in 2014
  - 6 more since, 1 removed
  - 4 years of data, learning, and experience
- 4 in deviated wells (max angle 41°)
- 1 as an initial completion
- LGRs between 2 and 110 bbl per mmcf
- Gas rates between 200 and 650 mcfd
One of the Original Duals

Liquid loading w/ 2 7/8” prior to rig event. Stable production since.

1.315” OD tubing
1.66” OD tubing

Flowing 600+ mcfd up both tubing strings
Well Name: Colvin, Bruce Gas Unit A 3
Location: SW/4, SEC. 19, T34N, R7W La Plata County, Colorado
Elevation: GL 6712', KB 6728'
Date: 12-Mar-2014
Spud Date: 13-Jun-2008

TOC = surface (circulated) behind 8.625" casing
1.9 x 1.66" crossover at 297'
8.625", 28#/ft, J-55 Casing
Casing set at 398'

This is a directional well (build and hold, max 41 degrees). Measured depths are shown on this diagram. For directional aspects, please see the deviation survey.

Perforations:
3098' - 3100'
3154' - 3162'
3198' - 3210'
3266' - 3270'
3286' - 3292'

.875" Q nipple at 3193'
Small tubing landed at 3197'
1.18" F nipple at 3253'
Large tubing landed at 3257'

1.9x1.66x1.315", 2.76x2.33x1.72 #/ft, J-55 Tubing
1.9x1.66", 2.76x2.33 #/ft, J-55 Tubing
5.5", 15.5 #/ft, J-55 Casing
TD: 3677'
5.5", 15.5 #/ft, J-55 Casing
Casing set at 3668'

FTP psig
SIBHP psig
SICP psig
FTP psig

WGR = 10 bbl/mmcf
Slope = 140 psi/ml

Pressure: psig; Temperature: deg F

10 bbl/mmcf
140 psi/ml

Large Tub Pressure
Small Tub Pressure
Large Tub Temp
3rd Gear, Both Tubings Open

Dual Flowing Production

Combined Flow
C.R. = 430 mcfd

Gas Production
Water Production
Gas Forecast
2nd Gear, Large Tubing Only
1st Gear, Small Tubing Only

Dual Flowing Production

- Gas Production
- Water Production
- Gas Forecast

Small String Flow
C.R. = 190
Designed Rate Range, With Actuals

Dual Flowing Production

- Combined Flow: C.R. = 430 mcf/d
- Large String Flow, 1.66" OD: C.R. = 240
- Small String Flow, 1.315" OD: C.R. = 190
Initial Completion, Dual Flow

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- Large
- Small
- Large
- Both

Changed landing depth (deeper)
Comparing Pressure Loss (Dual and Single)

Flowing Well Pressure Loss (Tubing Intake to Surface)
All Wells in Same Geographic Area
Dual Wells Highlighted

- Blue - Single String
- Purple - Dual, Flowing Both
- Green - Dual, Flowing Large
Comparing Pressure Loss (Dual and Single)

Observation: Similar pressure loss behavior between dual and single tubing flow under similar conditions.

Flowing Well Pressure Drop Comparison
LGR < 25 bbl/mmcf

- Blue - Single String
- Purple - Dual, Flowing Both

Tubing Pressure Drop, PSI / MILE
Flowing Gas Rate, MCFD
Casing / Tubing Combinations

- 7” casing
  - Any two of 2 3/8, 2 1/16, 1.9, 1.66, and 1.315”
- 5 ½” casing
  - Any two of 1.9, 1.66, and 1.315” (outside diameters)
**Cost / Value / Risk**

- **Cost**
  - Dual wellhead equipment
  - Rig cost to modify wellhead (if on an existing well)
  - Tubing
  - Flowline re-fab including valves / chokes

- **Value**
  - Up to three designed flow paths in one installation
  - Reduced expense by delaying/skipping future rig events
  - Seamless transition from one flow path to the next

- **Risk**
  - Restricted production if 3\(^{rd}\) gear planned but not reached
  - Shorter life if tubing develops hole
  - Complex fishing job
Operational Considerations

- Uses existing dual well technology
- Simple design
- Intuitive operation
- No need to monitor separate flow rates
  - The well will tell you when it’s time to switch
- Provides options for ramping up production after a downtime event
- Shut-in tubing can be used for chemical injection
Where To From Here?

- Share with industry, academia, see innovation
- More new wells
- Higher gas rates
- Different tubing combinations, casing flow
- Logic controllers
  - Automated chokes and valves
- Measure separate flow rates during 3\textsuperscript{rd} gear
- Modeling 3\textsuperscript{rd} gear critical rate

- Thank you for your attention
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Expected gas and liquid rates? Verify mist flow regime
- Non absolute guideline: Gas rate > 400 mcfd, LGR < 60 bbl / mmcf?
- Dry LGR wells provide best candidates

Casing size? Must be 5 ½” or greater.
- 5 ½”
  - Tubing sizes to consider: 1.9”, 1.66”, 1.315” ODs
  - Ask wellhead vendor for API 2.781” (2 50/64”) center to center dual equipment
    - Tubing hangers, adapter flange, master-valves, flow tees
- 7”
  - Tubing sizes to consider: 2 3/8”, 2 1/16”, 1.9”, 1.66”, 1.315”
  - Ask wellhead vendor for API 3.547” (3 35/64”) center to center dual equipment

Determine critical rate of each possible tubing size at well conditions
Supplemental: How To (Design)

- Choose two different sized tubing strings
  - To maximize operating economics and installation life based on expected production profile
- Determine landing depths
  - Use local single-string experience to guide this decision
  - If not to be landed at the same depth, consider landing the large tubing deeper
- Secure dual wellhead equipment from vendor
  - Tubing head or adapter spool w/ alignment pins, tubing hangers, adapter flange, dual master-valves and flow-tees
  - Flowline valves and chokes
- Rig operations follow existing dual well practices
If well is loaded, start in 1st gear
  ▪ Switch to next gear as production stream improves (liquids removed)
Once in stable 3rd gear, monitor / watch
If well won’t stay in 3rd gear, one tubing string will log off, the other will continue
Get well back into stable 2nd gear
  ▪ Open the other string, but through a choke
    ▪ Over time, open choke more
Wellhead Options

Dual tubing head (minimum height)

... or ...

Add spool w/ alignment pins and hanger above existing tubing head (adds to total height)
Experiences

- Install a jumper (with isolation valves) between flow lines for pressure measurement, and equalizing purposes
- Pay attention to landing depths
- Be prepared to choke one string to achieve optimized flow between 2\textsuperscript{nd} and 3\textsuperscript{rd} gears
- Avoid flowing one tubing above 2x its critical rate
- Consider higher grade steel tubing for longevity
Critical Rate of 3\textsuperscript{rd} Gear, Field Measurement

Critical Rate Observation, Both Tubings Combined
Dollahon 18U-11, LGR = ?, Vertical Well

Large tub, then opened both

Critical rate of both strings combined
491 mcfd, 9\% above 450

CR Small  190 mcfd
CR Large  260 mcfd
Add the two  450 mcfd

Water rate is unreliable. Do not assume water rate was zero because measurement says so.
Critical Rate of 3\textsuperscript{rd} Gear, Field Measurement

![Graph showing critical rate observation for both tubings combined.]

- **Critical Rate Observation, Both Tubings Combined**
  - Preston EE 4, LGR = 23 bbl/mcfd, Directional Well - 37°

- **Critical rate of both strings combined**: 406 mcfd, 23% above 330

- **Large tbg, then opened both**

- **CR Small**: 130 mcfd
- **CR Large**: 200 mcfd
- **Add the two**: 330 mcfd

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Sample Questions

- Have you considered casing flow too?
- Do you have to pull both strings to work on one?
- Which string do you land deeper?
- Could you put chokes on the separate flowlines for in-between flow periods?
- What if you don’t want a dual later?
- Are you consistent with the “sides” of the wellhead you land them on?
- What if your LGR turns out to be wetter than you predicted?
Sample Questions

- Is the critical rate of 2 combined strings as simple as adding the critical rates of each?
- Why do you show tapered tubing strings?
- Did you make any rookie mistakes?
- Can you swab or run a plunger?
- How do you design your tubing strings?
- Have you measured separate gas / water rates during 3rd gear flow?
- Could you install 3 tubing strings? A triple?