Preventing High Separator Level Events Without Sacrificing Well Performance

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Horizontal Well Flow Behavior


- The flow behavior of long horizontal wells is similar to pipelines (well horiz section) + riser (vertical section)
Cause of The High Level Problem

- **Riser-Induced Slugging**
  - A. Slug formation
  - B. Slug production
  - C. Gas penetration
  - D. Gas blow-down

- **Terrain Slugging**
  - A: Low spots fills with liquid and flow is blocked
  - B: Pressure builds up behind the blockage
  - C&D: When pressure becomes high enough, gas blows liquid out of the low spot as a slug

Feb. 4 - 8, 2007
2007 Gas-Lift Workshop

Feb. 4 - 7, 2018
2018 Artificial Lift Strategies for Unconventional Wells Workshop
Oklahoma City, OK
A “blowdown” induced tubing gradient reduction has consequences

- Wells much deeper than risers, so .05 psi per foot gradient decrease is
  - 25 psi pressure drop in a 500 foot riser
  - 500 psi pressure drop in a 10,000 foot well

Gas blowdown creates short term BHP drop
What happens when BHP drops?

- If no packer, casing pressure drops as gas rapidly enters the tubing, further reducing tubing gradient.
- Additional terrain slugging likely to occur as trapped gas in lateral expands, penetrating seals.
- Series of expanding gas slugs can seriously reduce tubing gradient.
- Reduced tubing gradient manifests as high tubing pressure for given BHP.
Punkin Chunkin

- What happens when a high pressure gas source is connected to a pipe with something inside it?

- "Big 10 Inch" takes world record shot of 5545 feet in Moab, Utah, September 9, 2010

- The Punkin Chunker barrel is your flowline

Aircraft Catapult
Velocity / Pressure Graph of 9mm round in 16” barrel

- Velocity increasing until round leaves barrel (Blue Line)
Before horizontal wells, installing a high level ESD switch was a uncommon
Impact to the Production Separator

- High pressure gas in tubing expands towards lower pressure separator, increasing velocity of flowline contents
- High velocity turbulent gas sweeps liquid from flowline rapidly into separator (in seconds)
- Separator designed to dump liquids at rates typically 2 to 10 BPM
- 48” x 10’ Separator holds 24 barrels, normally half full, leaving 12 barrels

20 barrel volume in less than 60 seconds = ESD
The Math of a mile long 4” Flowline

- Assume wellhead at 150 psi, separator at 100
- Weymouth formula predicts 51 ft/sec for gas
- Line capacity per foot: .014 barrel per foot
- Result is .71 barrel per second, or 20 barrels in 28 seconds
- 20 barrels is 1428 feet of 100% liquid flowline
- 20 barrels is 2856 feet of 50% liquid flowline, requiring 56 seconds

20 barrel volume in less than 60 seconds = ESD
How to Prevent the ESD Event

- Choke back wellhead flow during gas blowdown phase
  - Prediction of high level event needed as they happen fast, and choke may not react in time
  - Automated high pressure chokes expensive
  - Chokes exposed to all well fluids including sand, therefore prone to wear / cutout
How to Prevent the ESD Event

- Elevate the separator pressure commensurate with tubing pressure rise
  - Applies backpressure to the flowline and wellhead, reducing the driving force
  - Liquids depart separator faster
  - Common practice used to prevent ESD’s
  - Normally implemented by operator changing setpoint on pneumatic pressure controller
  - Results in extra well back pressure 24/7
How to Prevent the ESD Event

- Kimray liquid capacity chart
  - Rates double when pressure drop quadrupled
- Square Root of $\Delta P$ relationship
- Viable method to remove liquids quicker

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Pilot Test – Separator Pressure

- New high oil rate Delaware test well had high level ESD’s 3-4 times per week
- Automated separator pressure control system chosen over wellhead choke due to lower implementation cost and increased liquid removal rates
- Method needed to predict high liquid level events regardless of method chosen
  - Detecting level increases deemed too late to affect vessel pressure increase
Automating Separator Pressure

- Kimray 75 PG manual pilot replaced with Fisher I2P 4-20 mA transducer
Automating Separator Pressure

- All wellhead, flowline, and separator pressures monitored at high frequency (5 seconds) during two high separator level ESD events

- Data enabled statistical determination of indicators correlating pressure behavior to high level ESD events

- Algorithms installed in IoT enabled device controlling I2P transducer on separator gas backpressure valve, with calculations every 5 seconds
Algorithm Logic

- Detection of PLSGR Event
  - Observe normal difference between flowline pressure at wellhead, and separator pressure
  - Observe casing pressure, looking for slight drop
    - Can follow tubing gradient drop due to “terrain” blowdown
    - Drop severity an indication of gas blowdown severity
  - Employ statistics to tie observed high level events to observed pressure data, establishing correlation
- Wellhead flowmeters a more expensive option
- Separator level sensors “catching bullet”
  - If level sensors catch the level increase, it is too late
Algorithm Logic

- Completion of PLSGR Event
  - Once wellhead flowline pressure begins to drop, separator pressure setpoint is lowered
  - Separator level sensors confirm normal levels before lowering setpoint
  - Process repeats
Algorithm Logic

- **Optimal Separator Pressure Selection**
  - Separator pressure setpoint lowered until level sensors indicate level building
  - Pressure of oil and water receiving systems monitored
  - Statistics employed to determine lowest optimal separator pressure
  - No more guessing by operator on the separator pressure needed for liquids to dump

Result: Flowline Backpressure Optimization
Results

- High Level ESD frequency once per month from 3-4 times per week (93% drop)
- Separator pressure only elevated following PLSGR events
  - Minimizing back-pressure on reservoir
  - Maximizing well performance
- Well runtime significantly elevated
- Paid out project with first ESD prevention
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Slug Mitigation Method

- Increase GL gas rate
- Reduction of flowline and/or riser diameter
- Splitting the flow into dual or multiple streams
- Gas injection in the riser
- Use of mixing devices at the riser base
- Subsea separation (requires two separate flowlines and a liquid pump)
- Internal small pipe insertion (intrusive solution)
- External multi-entry gas bypass
- Choking (reduce production capacity)
- Increase of backpressure
- External bypass line
- Foaming