Downhole Flow Conditioning to Improve Well Production Economics

SPE Calgary Section Reservoir Evaluation and Production Optimization Luncheon

November 2016
Agenda

1. Challenges producing horizontal wells
2. Root cause analysis
3. Development of the HEAL System
4. Case histories
Common challenges with artificial lift in horizontal wells

High Total Well Capital Expenditure
- Large artificial lift equipment due to production rate, depth and low efficiency
- Multiple lift systems required after natural flow period
- Complex directional profile to achieve production and geological objectives

High Operating Expenses
- Excessive workover frequency due to poor reliability and downhole equipment failures
- Excessive energy consumption due to pump depth and low pump efficiency
- Excessive gas interference and poor runtimes

Production and Reserves not Maximized
- Inadequate drawdown due to lift system limitations (gas lift, “pump limited”)
- Pump placement limiting ability to pump off well to very low bottomhole pressures
- Persistent high annular fluid levels or pump inlet pressure
OPEX risks

Complexity of depth, temperature, fluid composition (gassy), rapidly declining rates has greatly increased risks to the artificial lift system:

- **Down Time Risk** – pump gas interference, gas slugs (dry operation, gas lock)
- **Run Life Risk** – solids, frac sand and fines, pump gas interference
- **Installation Risk** – debris from pervious well interventions, solids, precipitates, high DLS, casing issues
- **Downhole Flow Restriction Risk** – drilling cost reduction initiatives have reduced casing ID’s, limiting production drawdowns (the “600 psi producing BHP barrier”)
- **Excessive Operating Cost Risk** – frequent workovers and operator attention
- **Type Curve Risk** – production rate and drawdowns compromised with pumps landed above Hz section
Production engineer’s predicament

Intermediate artificial lift required before transitioning to rod pump

1. Production rate at bottom end of natural flow period is greater than top end of rod pumping capacity
   • Intermediate artificial lift required

2. Want to natural flow as long as possible (lowest OPEX)

3. Want to transition to rod pump as quickly as possible to minimize OPEX

4. Want to transition to rod pump as quickly as possible to maximize drawdown and well NPV
Reserves predicament identified

1. Artificial lift challenges are leading to a reserve write down risk:
   • actual production post high initial decline (tail phase) is below reserve booking
   • gas lifting limits drawdown, thus forced to transition to rod pump
   • gas lifting has higher OPEX, which reduces reserves booking
   • eventually must transition to rod pump for more drawdown and lower OPEX.

“We need a solution that maximizes drawdown reliably at lowest OPEX possible, while minimizing artificial lift system transitions”
Root cause of challenges: slug flow

Slug Flow Mechanisms:

1. **Hydrodynamic Based** – flow regime (rates, GLR and pressure)

2. **Terrain Based** – well geometry (undulations and toe-up trajectory)

3. **Operational Based** – interruptions, stops/starts, pump on timer = bad plan, pump over-stroking practices
How a well is drilled impacts slug flow

**Toe-up**
- Large gas bubble forms at toe
- Gas bubble eventually becomes unstable and releases in violent manner
- Large, extended gas flow periods

**Wellbore Undulations**
- Liquid traps compound slugging
- Liquid traps do not create material pressure drops, rather they exacerbate slugging
Gas expansion in an oil reservoir
Below 600 psi bottomhole pressure gas expansion is exponential

When producing BHP is < 600 psi:

- Slug flow severity increases dramatically
- Flow restrictions around downhole components amplifies slug flow
- Solids transport increases significantly

Gas expansion from 300 psi to 30 psi is 12 times
Slug flow transports solids along horizontal

Solids are transported in dunes along horizontal due to wave mechanics associated with slug flow.

Transported solids accumulate at the heel of the horizontal well, where pumps are commonly positioned – high risk of solids damage to pumps.

Solids dunes in horizontal caused by slug flow.

Source: www.evcam.com
Solids transport mechanism is slug flow

Reference:
Slug flow mitigation techniques

1. **Choke**
   Controlled pressure drop used to eliminate slugs (minimum 500 psi often required)

2. **Slug Catchers**
   Common in pipeline industry; large piping and process equipment required

3. **Flow Conditioning**
   Application of specific multiphase flow regimes to achieve the benefits of choking but without the pressure loss

Reference:
http://fluidsengineering.asmedigitalcollection.asme.org/data/Journals/JFEA/A/927034/fe_135_8_081304_f007.png
Slug flow mitigation techniques

Surface Choke Simulation

Impact of Horizontal Surface Choke Size
Total Liquid Production, Res Pres = 6000 psia, Toe-down

Fig. 10

Downhole Flow Conditioning Simulation

Impact of Production Tubing Size on Liquid Production
Insertion of 1.5 in Coiled Tubing String
Res Pres = 6000 psia, Toe-Up

Fig. 11

Reference:
H. Lee Norris III, SPE 158500, “The Use of a Transient Multiphase Simulator to Predict and Suppress Flow Instabilities in a Horizontal Shale Oil Well”, SPE Annual Technical Conference and Exhibition, San Antonio Texas, USA, 8-10 October 2012
Downhole flow conditioning

Development of the HEAL System

Reference: TriAxon Oil Corp. Harmattan East Viking Unit well 02/04-28-032-03W5
1. Flow conditioning (slug flow mitigation)

- Apply flow regime that suppresses slug flows
- Apply flow regime that reduces fluid density to lift liquids from horizontal to vertical
- Avoid foam generation
- Maximize gas separation efficiency
- Size for life of well

Mitigate slug flows with the HEAL System
Sized regulating string flow conditioning

Bubble Flow
Slug Flow
Annular Transition
Mist

Source: Purdue University http://bit.ly/1OxEjm3
Mitigate slug flows with the HEAL System

2. Place traditional artificial lift systems in vertical
   - Place moving parts (pump) in vertical for reliability
   - Smaller lift equipment or more capacity out of existing equipment
   - Lowers power consumption
   - Maximize drawdown

3. Solids control
   - Control solids transport mechanism in hz
   - Solids separator with large sump for collection of solids (to protect pump)
Longevity: HEAL system sized for life of well

Depleted Reservoir Operating Conditions:
- Same or Lower Sandface Pressure
- High Production Rate Relative to $Q_{\text{max}}$
- Remains Frictionally Dominated throughout Well Life (Ideal for Stable Flow)
HEAL System results and challenges

HEAL System demonstrates attractive value proposition of highly capital efficient production and reserves uplift.
Case Study: Reliability

• Ran pumps deep to maximize drawdown
  - multiple pump failures

• Ran pumps shallow for reliability
  - poor drawdown, rod breaks from gas interference

• Pre-HEAL
  - 9 pump changes in 2.25 years costing $600k

• Post-HEAL
  - Zero changes in 2+ years
Case Study: Reliability

Improved pump life and rod life in multiple installs in several basins:

- **Wolfcamp, Permian Basin**
  - longest running rod pump install for client and ongoing

- **Niobrara, DJ Basin**
  - for 2 years prior to the HEAL System, rod failures every 6 months
  - 12 months post-install, no rod failures, ongoing

- **Viking, Central Alberta, Canada**
  - multiple solids related pump failures post-flowback
  - since installs (20+) no failures

- **Belly River, Central Alberta, Canada**
  - multiple solids related pump failures
  - since installs (10+) no failures

- **Glauconite, Central Alberta, Canada**
  - multiple solids related pump failures
  - since installs no failures
Case Study: Gas interference, NEBC Basin

- Severe gas interference
- In the field, tried multiple downhole separator types (poor boy, packer style) with no improvement
- HEAL System has allowed same pump/rods/jack to more than double production
- Multiple wells in field with HEAL Systems with consistent production uplift
Case Study: Gas interference, Permian Basin

- HEAL System solves the root cause of erratic pump fillage
- Regardless of the performance of the downhole separator, like a properly designed packer style gas separator, slug flow leads to gas interference
- Erratic pump fillage compromises rod and pump life
Case Study: Gas interference, Niobrara DJ Basin

- HEAL System solves the root cause of erratic pump fillage
- Mitigating slug flows improves both downhole separation and pump performance
- Increase in pump efficiency and a shallower pump placement reduces energy consumption up to 40%
Slug flow is a major impediment to achieving a pumped off condition.

HEAL System positions pump in vertical section ~1200 feet above hz

- achieved lower producing BHP than a pump positioned at 80° inc

Pump placed at or above KOP to improve reliability and lower cost

- reduced size of pump / rods / jack (cost), while achieved reliable lower producing BHP

Case Study: Low producing BHP, SE Sask
Case Study: Low producing BHP vs gas lift, Montney

- Gas lift has attractive reliability, but high OPEX and producing BHP
- HEAL System + rod pumping sustained attractive reliability of gas lift, but at significantly lower OPEX and producing BHP
Case Study: Low BHP vs gas lift, Anadarko Basin

- Transition from ESP to gas lift resulted in undesirable production performance and higher OPEX
- HEAL System + rod pump maximized drawdown and the well production potential
Case Study: Production enhancement, Montney

- Montney suffers major rod pumping challenges: deep, high GOR, some areas have very high initial rates, high decline rates
- HEAL System installed in +18 wells with multiple operating companies
- Long term (>12 months) average result is +100% increase in production over previous trend
- Moving towards installing immediately after initial completion, full cycle
Case Study: Production enhancement, gas lift transition to rod pump, Permian Basin

- Wolfcamp formation is challenged by depth, high total fluid rates, high watercuts and severe high GOR gas interference
- Installation in 7 Wolfcamp wells resulted in a sustained +40% increase in production
HEAL ESP System Pad Field Trial … *Installed Sept 2016*

**Project Objective**
- Drilled a 3 Well Horizontal Pad (~3000' to 7200' Hz sections)
- 2 wells conventional ESPs, 1 with HEAL ESP System
- Compare performance / cost reductions of HEAL System
- **HEAL System Goal**: Extend MTTF from 0.5 months to > 2 yrs

**Production Challenges**
- $\text{H}_2\text{S}$ up to 2%
- Solids production (frac sand) and scaling tendencies
- High liquid and gas rates / GOR’s (2000 to 3,000 scf/bbl)

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**DLS vs Inclination Comparison**

**102/14-23 Survey**
- ESP Landing Depths:
  1. 1042.9 m T.D. @ 0°
  2. Series 1760 Pump

**15-23 Survey**
- ESP Landing Depth:
  1. 1443.66 m T.D. @ 47°
  2. Series 2250 Pump

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3 Well ESP Pad Comparison

SHUT DOWN PERIODS TO REMOVE SAND

Initial start-up @ 52 Hz
3 Well ESP Pad Comparison

Initial Observations

- All wells suggest consistent drawdown
- Pipeline restrictions have impacted continuous operations @ 15-23 & 16-23
- Average Reductions at 14-23’s HEAL ESP System:
  1. 33% less HP/power
  2. 20% less pump stages
  3. 30% less tubing/cable
  4. Smaller Motor – 456 vs 562 series
  5. Considerably less solids in produced fluids

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<tr>
<th>WELL</th>
<th>GAS RATE (MCF/D)</th>
<th>TOTAL FLUID (BBL/D)</th>
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<tbody>
<tr>
<td>14-23 (HEAL)</td>
<td>900</td>
<td>1145</td>
</tr>
<tr>
<td>15-23</td>
<td>760</td>
<td>1182</td>
</tr>
<tr>
<td>16-23</td>
<td>500</td>
<td>1750</td>
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Summary

Flow conditioning for slug mitigation adds value

- Over 130 HEAL System installs across North America

Benefits of flow conditioning using Heal System

- Mitigate down time risks
- Mitigate run life risks (extend to 2-3 years target)
- Reduce OPEX and CAPEX
- Mitigate production type curve risks
  - Controlled drawdown, drawdown reliability and managing high GORs
  - Achieve very low producing BHP’s, reliably
Questions?

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