The Challenges of Pumping Horizontal Fractured Wells (Cardium, Bakken, etc.)

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With the dominance of drilling horizontal/fractured wells, comes a new combination of challenges to effectively/economically produce them.

<table>
<thead>
<tr>
<th></th>
<th>Alberta</th>
<th>Sask.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Spuds</td>
<td>3006</td>
<td>3166</td>
</tr>
<tr>
<td>Horizontal</td>
<td>2339</td>
<td>2174</td>
</tr>
</tbody>
</table>
Reciprocating Pump Systems
Just a few of the Problems/Challenges for Reciprocating Pump Systems

A. High initial production rates followed by steep declines

B. Gas interference

C. Difficult to understand/calculate the IPR

D. Deviated wellbore
High IP’s require larger pumping systems – followed by steep production declines –

What are your options:

1. Install large/different pumping system to capture high IP
   A. Leave it in anticipation of increased production later (waterflood or EOR potential)
   B. Move larger equipment to a new location and backfill with smaller system
   C. Leave it – too expensive (or too busy) to move

2. “Live” with lower rates early in well life

3. Ensure that system efficiency will provide necessary net pump displacement to achieve desired rates.
Challenges Of Rapid Declines

- How does my pumping system react to the change(s) in production rates – match displacement to inflow
  - How do I know if it needs to change??
- What is the cost of reducing displacement
- What is the cost of NOT reducing displacement in a timely manner
  - Fluid pound
  - System efficiency losses
  - High operating costs
  - Other operational issues
Dynamic inflow rates and Gas-Liquid-Ratios (GLR) – Erratic Pump Efficiency/Production rates

• “Erratic” production rates may be due to:
  • Horizontal leg is not “flat”
  • Horizontal leg is “toe down”
  • Poor downhole gas separator design
  • Erratic inflow
  • Damaged formation
Results Utilizing Dynamic Changes

**TABLE 1—WELL A: COMPARISON OF PUMP PERFORMANCE FOR CONSTANT AND OPTIMAL VARIABLE SPEED**

<table>
<thead>
<tr>
<th>Pumping Parameters</th>
<th>Speed Profile</th>
<th>Change (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Constant</td>
<td>Optimal</td>
</tr>
<tr>
<td>SPM</td>
<td>3.9</td>
<td>6.9</td>
</tr>
<tr>
<td>Plunger stroke length (in.)</td>
<td>74</td>
<td>86</td>
</tr>
<tr>
<td>Pump leakage (B/D)</td>
<td>27.4</td>
<td>27.1</td>
</tr>
<tr>
<td>Pumped volume (B/D)</td>
<td>107</td>
<td>249</td>
</tr>
<tr>
<td>Max. Goodman factor (%)</td>
<td>92</td>
<td>92</td>
</tr>
<tr>
<td>Energy consumption (kWh/bbl)</td>
<td>1.61</td>
<td>1.56</td>
</tr>
</tbody>
</table>

Reference 2
Gas Interference – What's the big deal??

The traditional vertical well typically offered a “sump or cellar” which enable the pump intake to be below the producing interval – creating a natural gas separator.

Horizontal wells typically do not have a “sump/cellar”
Gas Interference

• Gas in the pump may result in:
  • Poor pump efficiency causes reduced displacement and potentially lost production
  • Gas locking resulting in reduced equipment life and additional production problems – surface and downhole
  • Poor energy efficiency
  • Increased failure rates
Traditional methods to combat Gas Interference

- Tap the pump
- Dip Tube
- Mechanical devices to “open” the traveling valve (i.e. gas lock breaker)
- Poor Boy Design of gas separator
Understand Your Pump Efficiency
The Basic Calculation

\[ V = 0.0119 \times \frac{GD}{ID^2 - OD^2} \]

Where:

- \( V \) = velocity of fluids
- \( GD \) = gross pump displacement, BPD (not actual production)
- \( ID \) = inside diameter of large tube, in
- \( OD \) = outside diameter of small tube, in

**Important Note:** Gas bubbles rise at a maximum velocity of about 0.4 ft/sec. If fluid velocity is 0.4 ft/sec or greater, separation will be poor.
Why doesn’t my separator work?

Poor Boy Separator

Production = 300 bbls
Constant = 0.0199
ID of poor boy = 1.995 in
OD of the dip tube = 1 in

\[
\frac{300 \times 0.0199}{1.995 \times 1.995 - 1 \times 1} = \frac{5.97}{2.98}
\]

Downward Fluid Velocity = \textbf{2.003 ft/sec}
Various types of separators are available – do your homework

Investigate various types/styles of separators – different applications/well “needs”

• Poor boy/modified poor boy
• Packer style separator
• Weighted intake
• Natural gas separator
Not one style works for every case!

**Weighted Inner Mandrel**
Orients with gravity so only liquids can enter the flow tube ports
Effect of Gas Interference on System Design

Oil Production Rate at Pump Conditions (bpd): 203
Water Production Rate at Pump Conditions (bpd): 0
Free Gas Production Rate Through Pump (ft³/d): 104
Pump Capacity Lost Due To Mechanical Slippage (bpd): 0
Total Pump Capacity Required (bpd): 308
Equivalent Stock Tank Liquid Volume (bpd): 200
Apparent Pump Efficiency (%): 65
Volume Of Free Gas Vented (ft³/d): 4,975

Diagram:
- Pump Capacity for Oil (BPD)
- Stock Tank Oil (BOPD)
- Pump Capacity/Stock Tank For Water (BPD)
- Pump Leakage (BPD)
- Pump Capacity for Free Gas (BPD)
To Combat Gas Interference

- Ensure your pump spacing is minimized
- Utilize pump accessories as required
  - Top gas check
  - Gas lock breaker
- Use small diameter pumps in combination with long stroke length to maximize compression
Difficult to understand/calculate the IPR

Traditional Vogel IPR often may not “work” for horizontal wells

Why doesn’t it work??
• Heterogeneous reservoir
• Static pressure has changed
• Inaccurate producing pressure
The Value of Maximizing Drawdown

• Ensure that fluid level (drawdown) is understood and pumped down effectively
• Evaluate pump efficiency and ensure net pump capacity is adequate
• Minimize casing pressure – utilize casing gas compression – results may exceed what you would calculate with IPR
Results of Increased Drawdown

TO DATE WITH THE HELP OF THE GASJACK, THE WELL HAS PRODUCED 48,000 BO AND 55 MMCF OF GAS

SET GASJACK ON CASING SIDE OF PUMPING OIL WELL

PROJECTED DAILY OIL RATE WITHOUT GASJACK AND CALCULATED CUMULATIVE PRODUCTION OF 2,000 BO AND 20 MMCF OF GAS WITHOUT THE GASJACK.

2009
2010
2011
2012

Oil (Mcfd)

1
2
3
4
5
6
7
8
9
10

Oil (bbl)

1
2
3
4
5
6
7
8
9
10

Gas (MMcf)

1
2
3
4
5
6
7
8
9
10

Proj Oil Cum: 85.62 Mbbbl
Oil Rem: 0.00 Mbbbl
Oil EUR: 85.62 Mbbbl

Proj Gas Cum: 66.62 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 66.62 MMcf
### Understand the Fluid Level and PIP

<table>
<thead>
<tr>
<th>No.</th>
<th>Column Length (m)</th>
<th>Average Gradient (kPa/m)</th>
<th>Column Pressure (kPa)</th>
<th>Column Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>872.1</td>
<td>0.126</td>
<td>105.7</td>
<td>Gas Column</td>
</tr>
<tr>
<td>2</td>
<td>283.9</td>
<td>1.602</td>
<td>454.8</td>
<td>Oil Column</td>
</tr>
<tr>
<td>3</td>
<td>106.3</td>
<td>2.890</td>
<td>307.2</td>
<td>Oil Column</td>
</tr>
<tr>
<td>4</td>
<td>79.6</td>
<td>5.293</td>
<td>421.3</td>
<td>Oil Column</td>
</tr>
<tr>
<td>5</td>
<td>20.2</td>
<td>5.802</td>
<td>118.8</td>
<td>Emulsion Column</td>
</tr>
</tbody>
</table>

![Graph showing fluid level and pressure interface](image)

**PBHP = 2,805.4 kPaa @ MPP**
The Cost of Low Drilling Costs

The desire/economics to drill less expense/smaller diameter wellbores may create problems for the pumping system:

- Tighter annular area may create problem for gas separation – fluid velocity
- Smaller ID does not allow for installation of “large” diameter gas separator
- May create “tighter” radius through deviation creating areas that are difficult to effectively pump
Deviated wellbores may result in very high rod-tubing contact (friction) which often leads to premature equipment failures.

- Optimization starts before you drill the well – design a well bore that can be pumped!!!
- Friction does not “go away” – we must design a system and utilize “tools” to minimize wear and extend equipment life.
Dogleg severity, DLS $^\circ$/30m

Combination of build and turn rate; normalized measure of curvature (bend and turn) at a certain point. High doglegs pose difficulty in tripping and running casing or liner.
“Other” Artificial Lift Options – what will work or help in your case??
Summary

To effectively optimize horizontal wells:

- Design the well (prior to drilling) acknowledging the ongoing production challenges
- Continuously evaluate and understand the changing conditions – with particular emphasis during the high IP and decline phase(s)
- Apply technologies and methods that enable the pumping systems and personnel to react to change
- Understand that each well may have its own unique (and potentially peculiar) set of challenges – and they change!!
- Measure before and after – understand what works – and what doesn’t – don’t be afraid to change tactics
Q & A

Insanity: doing the same thing over and over again and expecting different results.
Albert Einstein
Acknowledgements/References

• Prime Pump Industries
• Spirit Global Energy Solutions
• Compressco Canada
• NR-Tec Ltd.
• Lufkin – SROD
• Tundra Solutions
• Premium ALS

References

• Improved Downhole Gas Separators, J. McCoy & A.L. Podio
• Optimizing Downhole Fluid Production of Sucker-Rod Pumps with Variable Motor Speed – K. Palka, J Czyz
Canadian Artificial Lift School
Hyatt Regency | Calgary, AB | April 2-3, 2013

Who Should Attend:
- Production Engineers
- Field Operators
- Production Technologists
- Field Foremen
- Engineering Firms
- Optimization Personnel
- Service/Production Suppliers

Topics Covered:
- Design Considerations/Selection
- Optimization & Trouble Shooting
- Automation & Control Systems
- Progressive Cavity Pumping
- Electric Submersible Pumping
- Rod Pumping
- New Technologies
- Gas Well Dewatering
- Plunger Lift
- Wellhead Compression

Registration Now Open!
Keynote Speaker
Olympic Gold Medalist
Jon Montgomery

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Thank You

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