UGV: Production Optimization by PipeSim @Schlumberger

Mykhailo Bratakh
Midstream Department
September, Monaco
UGV: “mature fields” VS “green field”

90% brown fields

- No pigging
- Coupled flowlines
- Production coefficient ≥ 85%
- Skin-factor effect
- Liquid loading
- Great back pressure
- Operation pressure ≤25 bar

Gas depletion drive mechanism

- 90% of total production
- More than 4000 wells
- Tight gas mostly
- Operation pressure ≤25 bar

Need of HF

- 10% green fields
- HP transmission lines

Location far from the exiting facilities

- 10% of total production
- 90% brown fields
- No pigging
- Coupled flowlines
- Production coefficient ≥ 85%
- Skin-factor effect
- Liquid loading
- Great back pressure
- Operation pressure ≤25 bar

More than 4000 wells
PipeSim – UGV production optimization pilot project (2018)

PipeSim screening criteria to choose:
- MS Excel: ≈ 10 days for 1 well
- Analogue software: ≈ 2 days for 1 well
- PipeSim: 1 day for 1 well

PipeSim Pilot Project results:
- Modelling accuracy: 3.5%
  - 185 MSCMD – actual ΔQ
  - 191 MSCMD – model ΔQ
- Proper candidates to pressure decreasing
- Overage ΔQ in 2018 – 2019 + 10%
Brown fields: Production and Gathering system. Bottleneckings vs debottlenecking

Nodal analysis: find bottlenecking (to estimate the impact on production)
- Local resistance in CPF and FPF;
- Backpressure in trunk-lines, brunch-lines and flow-lines;
- Liquid loading on the wellbore;
- Hydrates, paraffin and salts.

Sensitivity analysis: debottlenecking (to model how the wells will react on):
- Pigging of trunk lines and flow-lines;
- Choosing optimal liquid unloading method;
- Flow-lines decoupling;
- Booster installation;
- Tubing changing.
Actual pressure drop in gathering system: optimal vs backpressure

Backpressure:
- Liquid slugs inside the flow-lines;
- Chocking at the FPF;
- Local resistance in the outdated valves;
- Liquid loading in the lowest spots of the pipelines;
- Excessive pressure drop in the orifice plates

ΔP=-1,55bar

ΔQ=+120 млн. м³/год
+2 % годовой добычи
Flowlines’ pigging

Actual average wellhead pressure 7.5 bar

$\Delta P_{\text{actual}} = 1.75$ bar

Liquid hold-up level up to 80 %

$w_{\text{actual}} = 3.5$ m/sec

Actual inlet pressure 5.75 bar

Forecasting $P_{\text{act}} = 5.9$ bar

After pigging $\Delta P = 0.24$ bar

Expecting production +7% to actual production

Pigging
Liquid unloading

<table>
<thead>
<tr>
<th>Well#</th>
<th>GWR, %</th>
<th>GWR, scm/MMscm</th>
<th>Bottom hole pressure, bar</th>
<th>Liquid hydrostatic pressure, bar</th>
<th>Liquid volume, scm</th>
<th>Flowrate, MSCMD</th>
<th>Expected additional production, MSCMD</th>
<th>Expected additional production, MSCMY</th>
</tr>
</thead>
<tbody>
<tr>
<td>202</td>
<td>actual</td>
<td>26,90</td>
<td>96,442</td>
<td>41,020</td>
<td>0,6229</td>
<td>54,486</td>
<td>15,127</td>
<td>5,521</td>
</tr>
<tr>
<td></td>
<td>75</td>
<td>20,18</td>
<td>95,725</td>
<td>40,133</td>
<td>0,6016</td>
<td>55,960</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>13,45</td>
<td>95,030</td>
<td>39,276</td>
<td>0,5824</td>
<td>57,378</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>6,73</td>
<td>94,400</td>
<td>38,491</td>
<td>0,5684</td>
<td>58,655</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>0</td>
<td>88,812</td>
<td>30,813</td>
<td>0,3726</td>
<td>69,613</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Continuous**: ESP, Plunger lift, Tubing change, Gas-lift continuous, Foaming through capillary tube
- **Periodic**: Gas-lift periodic, Vents (WH pressure decreasing), Coiled tubing, Foaming (solid based)

Actual production → Expecting production - up to 30% to actual
Flow-lines decoupling

Early stage – green field

Before decoupling (1)

<table>
<thead>
<tr>
<th>Well #</th>
<th>P, bar</th>
<th>Q, MSCMD</th>
</tr>
</thead>
<tbody>
<tr>
<td>56</td>
<td>27.96</td>
<td>3.909</td>
</tr>
<tr>
<td>58</td>
<td>54.88</td>
<td>43.456</td>
</tr>
</tbody>
</table>

After decoupling (2)

<table>
<thead>
<tr>
<th>Well #</th>
<th>P, bar</th>
<th>Q, MSCMD</th>
</tr>
</thead>
<tbody>
<tr>
<td>56</td>
<td>18.02</td>
<td>4.014</td>
</tr>
<tr>
<td>58</td>
<td>41.87*</td>
<td>58.847</td>
</tr>
</tbody>
</table>

Δ 2-1

| Well # | | |
|--------| | |
| 56     | -9.94 | 0.105 |
| 58     | -13.01| 15.391 |

Brown field

FPF

FPF

# 58

P₁ = P₂ = P₁\text{\textsubscript{\text{wh}}}-high enough to ensure Q↑

P₁ ≤ P₂

Q₁ ≤ Q₂

P₂

P₂

Q_{\text{total}}↓
Boosters

Suction pressure 8 bar
Suction pressure 2 bar
Production 88 MSCMD
Production 125 MSCMD
16 wells large capacity boosters at CPF
16 wells 5 small boosters
Payback period – 6 months additional production + 37 MSCMD
Tubing change

Текущее состояние

МДКС

Замена НКТ
Further cooperation in production optimization

- To work with each well
- To choose the optimal liquid unloading methods
- To estimate the impact of sidetracking, new drilling or HF effect on production from LP wells
- Which will ensure 85% of UGV production
- Expected additional production +5-7%

Further cooperation in «green field» development

- To choose the proper artificial method
- To choose proper equipment
- To size production gathering system
- Which is goal of company strategy
- Oil & HC production increasing
Дякуємо за увагу!