Backflow and Clean-up of Golden Eagle water injection wells using Nitrogen gas-lift

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Background

- Golden Eagle water injection wells were completed with standalone screens run in an oil based mud. Some wells were single zone, others were 3-zone with interval control valves (ICV’s).
- Punt intervals were oil bearing, Burns intervals were in the aquifer (water bearing).
- Removal of the drilling fluid and filter cake prior to water injection was key to good injection performance.
- Back-flowing was considered a better option than mud breaker fluids.
- 4 Platform wells and 1 Subsea well were back-flowed in this way.
Velocity & Flowrate required to Clean Up Solids from Well

- 200 micron solids particle lifted from well if flow velocity > 0.5 m/s*
- 4000 b/d (~3bpm) target rate gives 0.6 m/s
- Maximum backflow rate is limited by three factors:
  - 2” temporary pipework between the injector and production well.
  - Filtration capacity on the temporary well test package (to achieve <30 mg/L oil in water prior to discharge).
  - N₂ tank storage, which is limited by deck space
- Backflow up to 5 tubing volumes to clean up the well (~10 hrs)

* Flow velocity must be greater than the particle settling velocity. Stokes Law for spherical objects is typically used to calculate settling velocity but Jimenez & Madsen (2003 Journal of Waterway, Port, Coastal & Ocean Engineering) formula gives a higher velocity i.e. worst case

\[
W_\ast = \frac{w_s}{\sqrt{(s-1)g d_N}} = \left( A + \frac{B}{S_\ast} \right)^{-1}
\]

\[
S_\ast = \frac{d_N}{4v} \sqrt{(s-1)g d_N}
\]
Gas-Lift Design Parameters & Workflow

<table>
<thead>
<tr>
<th>Input</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Design Backflow / Clean-Up Rate</td>
<td>4000 b/d oil or water</td>
</tr>
<tr>
<td>N₂ Lift Rate</td>
<td>1 MMscf/d (~750 scf/min)</td>
</tr>
<tr>
<td>THP min</td>
<td>300 psi</td>
</tr>
<tr>
<td>CHP max (A Annulus HP Alarm set point)</td>
<td>2500 psi</td>
</tr>
<tr>
<td>Unloading Gradient</td>
<td>9.6 - 9.8 ppg (~0.5 psi/ft)</td>
</tr>
<tr>
<td>Max IPO Valve depth</td>
<td>~4500 ft TVD to stay closed against a column of brine in Water Injection mode</td>
</tr>
</tbody>
</table>
IPO Valve Design Objectives

• During gas lift/backflow operation:
  • Check valve to remain fully open during N₂ injection and the bellows are fully compressed and protected
  • Dome pressure set to ensure full valve stem opening (7.5 mm travel) achievable during backflow with available CHP
  • Over-pressure of IPO bellows during backflow is sufficient and achievable with available annulus pressure

• Post gas lift/backflow operations (injection):
  • Retain a column of completion brine once the annulus was topped up with 9.3 ppg brine prior to water injection
  • Dome pressure is set high enough to ensure that the valve does not re-open once on injection causing the annulus fluid level to drop (a standard orifice valve will open with minimal ∆P between annulus and tubing)
  • Dome pressure required to accommodate the temperature range between back flow (~70°C) and minimum water injection (~20°C)
Tubing Shearable IPO Unloading Valve
Gas-Lift Design

- Evaluate sensitivity on injection rate and depth

- Three cases with varying PRes / PI & WC considered

- Maximum depth of injection limited to ~4500 ft TVD to ensure IPO valve holds a column of brine during water injection phase

- Maximum lift gas rate limited by Nitrogen tank on deck storage capacity (3 tanks gives ~ 1.5 MMscf working volume, 24 hrs pumping)

- 4000 b/d minimum backflow rate not achievable in all cases
- Use IPO valve to unload annulus of brine
- Inject $N_2$ at 100 psi above the valve opening pressure during clean-up (c. 2215 psi on surface)
- Opening/closing pressures calculated at 68°C (flowing temperature)
- Slight IPO over-pressure (7 bar) to ensure protection of bellows from cyclic stress
Gas-Lift Valve Opening/Closing range during Water Injection

- IPO opening & closing pressures re-calculated at 20 °C (lowest water injection temperature)
- Annulus brine gradient c. 290 psi lower than Valve Closing Pressure (worst case @ 20 °C)
- A deeper IPO would give higher back-flow rates but reduce the safety factor for holding a brine column
Gas-Lift Design

- Orifice sizing for 1 MMscf/d (~700 scf/min)
- 10/64” minimum size available
- Flow is critical for design case
- Injection of 2215 psi at surface required to fully compress the IPO bellows and protect from cyclic stress
Backflow Upper Zone (Zone 1) With Nitrogen Assist

Initial Status: kill weight fluid in well

1. ICV1 open
2. ICV 2,3 closed

Kick-off & unload brine/drilling fluid with N₂

Backflow 5 tbg volume of oil
Backflow Middle & Lower Zones (2 & 3) With Nitrogen Assist

- ICV 1 Closed
- ICV 2 Open then Closed
- ICV 3 Closed then Open

Backflow Zone 2 with N\textsubscript{2} assist

Backflow Zone 3 with N\textsubscript{2} assist

Tubing full of formation water at end of backflow

Nitrogen to be displaced back to 9.3ppg brine after backflow

- NaCl brine
- Drilling Fluid
- Oil
- Formation Water
• Start \( N_2 \) injection, CHP increasing [1]
• First flow from well at CHP = 2370 psi, higher pressure than expected [2]
• Test separator level control valve (LCV) opened. Large liquid slug and sharp drop in CHP [3]
• Stable brine unloading rate established at c. 0.3 bpm (< 1 bpm limit for valve flow cutting) [5]
• Annulus unloaded, a sharp drop in BHP and a large slug of fluid in the separator [6]
• Stable flow achieved at an average rate of 6400 bpd, 700-750 scf/min [9]
• \( N_2 \) injection stopped after 5-6 tubing volumes well shut-in [10]
## Summary Results

<table>
<thead>
<tr>
<th>Well</th>
<th>Zones</th>
<th>Valve MD ft</th>
<th>Valve TVD ft</th>
<th>Orifice Size</th>
<th>TRO @ 18 °C (psi)</th>
<th>N₂ Rate (scf/min)</th>
<th>Back Flow Rate (b/d)</th>
<th>Backflow to</th>
</tr>
</thead>
<tbody>
<tr>
<td>HIE</td>
<td>1</td>
<td>3574</td>
<td>3200</td>
<td>10/64</td>
<td>1773</td>
<td>1000</td>
<td>5000 (water)</td>
<td>Well Test Package to burners or filtration</td>
</tr>
<tr>
<td>BIA</td>
<td>3</td>
<td>3998</td>
<td>3978</td>
<td>13/64</td>
<td>2070</td>
<td>1300</td>
<td>3500 (water) 4000 (oil)</td>
<td>Platform Test Separator via piggy back well</td>
</tr>
<tr>
<td>BIB</td>
<td>3</td>
<td>4227</td>
<td>3665</td>
<td>12/64</td>
<td>2063</td>
<td>1000</td>
<td>3000 (water) 3800 (oil)</td>
<td>Platform Test Separator via piggy back well</td>
</tr>
<tr>
<td>DIA (subsea)</td>
<td>3</td>
<td>4051</td>
<td>3769</td>
<td>12/64</td>
<td>2195</td>
<td>750</td>
<td>5000 (oil &amp; water)</td>
<td>Well Test Package to burners or filtration</td>
</tr>
<tr>
<td>CIA</td>
<td>1</td>
<td>4522</td>
<td>3616</td>
<td>10/64</td>
<td>2088</td>
<td>750</td>
<td>6400 (oil)</td>
<td>Platform Test Separator via piggy back well</td>
</tr>
</tbody>
</table>

### Observations:

- The CHP limit of 2500 psi should be reviewed and if possible increased to give a wider operational window to work with.
- 2” temporary flowline creates a higher THP than expected (450 psi vs 300 psi design).
- 10/64” orifice has a nitrogen injection limit of around 750 scf/min (injecting at higher rates increased the pressure in the annulus, with no rate increase through the valve).
- Water injection achieved target rates with no evidence of mud impairment.
Acknowledgements

Successful implementation of this project required the teamwork and co-operation of numerous individuals, in particular within the Drilling, Completion, and Production Engineering teams.

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