C02 / Acid Gas Injection Well Conversion

Prepared for the 5th Well Bore Integrity Network Meeting.

Calgary Alberta

May 14, 2009
Agenda

• Wellbore integrity
• Well design with annular integrity
• Well design without annular integrity
• Elastomers
• Coatings
• Threads
• Risk & Cost
• Best practices
• Conclusions
The issue of cement integrity and bonding as well as cap rock competency/ integrity are outside the scope of this presentation and will therefore focus on the conversion and repair of wells for injection!
Well Bore Integrity

Well bore failures are either external or internal.

• External failure could occur as a result of:
  • Leakage via cement channeling/deteriation (poor primary cement)
  • External casing corrosion (incorrect cement formulation)
  • Casing thread leaks (wet C0₂ in reservoir)

• Internal failure
  • Packer leak
  • Tubing leak
  • Corrosion (wet C0₂ in flow stream and or reservoir)
• This injection well example assumes that cement quality and bond were acceptable, external casing condition is good and is suitable for internal conversion.

• The existing completion is pulled and the well is prepped for conversion to injection by cleaning and stimulating if necessary.

• An injection packer is set high enough to facilitate monitoring logging but must be kept within the injection zone to provide annular pressure isolation to the top of that zone.
This example assumes that near well bore annular communication/channelling exists and must be repaired outside the well bore but within the bore hole.

- Existing production casing must be of fair or better condition.
- Previous failed completion to be removed and well prepped for workover.
- Set composite material bridge plug above the perforations to isolate injection interval.
- Section mill (remove) the production casing across the upper section of the injection zone and past the cap rock.
- Under ream back to the original bore hole to expose uncontaminated rock.
Run a conventional rotating liner hanger with standard cementing float equipment

Liner hanger and float equipment can be low alloy carbon steel

The liner pipe across the injection zone and into the cap rock should be CRA (corrosion resistant alloy) to prevent internal/external corrosion and facilitate setting of the injection packer thereby mitigating internal corrosion as well
• Rotate the liner during cement displacement to improve the cement bond with the pipe and bore hole by reducing laminar flow

• Keep the liner well centralized to improve liner concentricity within bore hole

• Use CO₂ and acid gas resistant cement
Design Without Annular Integrity

- Drill out excess cement from the production casing to top of liner
- Drill out cement inside the liner and float equipment
- Pressure test the liner and cement job to confirm integrity
- Drill to top of the composite bridge plug and circulate clean
- Run under reamer and drill out the composite bridge plug and clean to bottom.
- Stimulate the perforated interval if required
- Run cement integrity, tracer & temp logs to confirm annular integrity
Design Without Annular Integrity

- Run the injection packer on wireline or work string
- Set the packer near the bottom of the CRA casing
- Run the internally coated injection tubing and latch onto the packer
- Pressure tested to confirm annular integrity and land in the optimum (modeled) condition to minimize or eliminate tubing cycling
Design Without Annular Integrity

- This example assumes the original production is poor to very poor condition and will not allow downhole tools to be set.
- The well is underreamed across the perforated interval and the liner cemented accordingly.
- Re-perforating and possible stimulation will be required.
- Controlling fluid and cement losses will be difficult in depleted reservoirs and may require creative temporary plugging techniques to hold cement in place while setting.
- Need to consider how those losses will affect the injectivity post workover.
• API Connections
  • Round thread type
  • Buttress thread type
  • Sealing relies on thread compound/dope
  • Examples; EUE, LTC, BTC
  • Should not be used without additional sealing aids for C0₂ & Acid Gas injection
  • Should not be used for casing threads
• Premium connections
  • Metal to metal seal
  • Gas-tight, resistance to severe well conditions, expensive
• Manufactured outside API specification
• Examples; Vam, Hydri, Teneris, Hunting
Commonly used anti corrosion coatings for tubing

- Coating types, phenolic, epoxy, urethane, nylon, fiberglass (GRE), HDPE & EXPE
- Thick film up to 25 – 30 mils
- Susceptible to damage from intervention
- Premium threads pose coating challenges
- Suppliers, Tuboscope, Bison, MasterKote & Rice Engineering
Tubing/ Coupling Protection

Reference band

Corrosion Barrier Ring

Grout

Flare

Liner

Rice Engineering “DUOLINE” EUE Connection With CB Ring
ENC Coatings

- Electroless nickel coating (ENC).
  - Has been used for coating downhole tools in CO₂ injection applications since the mid 1980’s in West Texas
  - Has excellent performance in CO₂ injection applications & is now being used in Acid Gas injection but too soon to determine long term performance
  - Resistant to C0₂ & moderate H₂S
  - Thickness ranges between .0001” and .003”
  - Surface hardness = 480 to 600 HV (resistant to erosion)
  - Cost is comparable to PFA & FEP coatings
  - An excellent alternative to CRA (corrosion resistant alloys) in many applications but not a replacement
• CO₂ has no chemical effect on elastomers but is easily compressed and can lead to explosive decompression damage in seals
• HNBR was in part developed to combat the effects of CO₂ exposure by offering better resistance to explosive decompression and to amine corrosion inhibitors
• Exposure to higher H₂S concentrations (>2%) tends to harden most elastomers such as NBR & HNBR therefore materials such as TFE/P (Aflas) are recommended for packer elements
• FFKM materials such as Kalrez and Chemraz are well suited for acid gas injection at all temperature ranges up to ~260°C (500°F)
• TFE/P (Aflas) is well suited for CO₂ but may be effected by the cool bottom hole temperatures on shallow and high rate injection wells
• Use the highest possible Shore A Durometer (hardness) elastomer as possible to minimize gas impregnation
• Both test samples were 90 durometer HNBR material but different blends from different vendors
• Autoclave Environment; 98% CO\textsubscript{2}, 2% H\textsubscript{2}S, 60K ppm Cl H\textsubscript{2}O for 40 hrs
## C02/ Acid Gas Injection Well Risk & Cost Matrix

<table>
<thead>
<tr>
<th>Casing Size</th>
<th>Injection Is Contained Within The Zone</th>
<th>Injection Out Of The Zone</th>
<th>Ability To Rotate During Cementing Ops.</th>
<th>Suitable For Use With Standard Injection Packer</th>
<th>Containment Confirmation With RA Tracer Log</th>
<th>Containment Confirmation With Temp Survey</th>
<th>Time Expected</th>
<th>Cost Expected</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Casing Size 177.8mm</strong></td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Red" /></td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Orange" /></td>
<td><img src="#" alt="Orange" /></td>
<td>19 Days</td>
<td>$460K</td>
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<tr>
<td>Liner cemented across the injection zone, cap rock and upper formation</td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Red" /></td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Orange" /></td>
<td><img src="#" alt="Orange" /></td>
<td>19 Days</td>
<td>$450K</td>
</tr>
<tr>
<td>Liner cemented across the injection zone, cap rock and upper formation with under reaming</td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Red" /></td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Green" /></td>
<td><img src="#" alt="Orange" /></td>
<td><img src="#" alt="Orange" /></td>
<td>23 Days</td>
<td>$670K</td>
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<td><strong>Casing Size 139.7mm</strong></td>
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<td><img src="#" alt="Orange" /></td>
<td><img src="#" alt="Orange" /></td>
<td>Under Review</td>
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<td><strong>Casing Size 114.3mm</strong></td>
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**Probability Of Success Legend**

- **Excellent**: Yes
- **Good**: Yes
- **Fair**: No
- **Poor**: Yes
- **N/A**: No

**Suitability Legend**

- **Yes**: Green
- **No**: Red

**Containment Confr. Legend**

- **Yes**: Green
- **No**: Red

*Simplified Version For Presentation Purposes*
Best Practices

- Accurately determine the wellbore pressure/ temperature changes and model the optimum state to land the tubing in (tension where possible)
- Minimize (eliminate) the dynamic movement of down hole tool seals to improve performance and life expectancy of equipment
- Cement CRA casing joints across and well above the storage formation for setting of tools and external corrosion management
- Manage abrupt pressure changes to avoid explosive decompression of elastomers
- Properly selected permanent packer will perform better and out last retrievable packers and plugs
A well bore of a minimum size and most any condition can be repaired and or converted for the purpose of CO₂ & acid gas injection

Depleted reservoirs may be difficult to effectively cement (new or old wells)

Better cement placement practices will yield better results regardless of cement type

Proper material selection can balance costs with reliability & performance

Risk and cost increase as casing size decreases
Conclusions

Thank you

Questions?

mwoitt@rpsgroup.com