Workshop: Minnelusa I

Day 3
10:40 – 11:40 am
ASP Blend Optimization Challenges and Strategies
Outline

- Introduction: Critical Issues
- Issues specific to Minnelusa reservoirs
- Minnelusa ASP Design Example
- Minnelusa SP/ASP at higher temperature
- Summary
Issues specific to Minnelusa

- **Chemical methods critical constraints:**
  - Reservoir characterization → Conformance & location of ROIP.
  - Water source → Fresh vs. produced
  - Rock-fluid interaction → Calcium sulfate!

- **What about Minnelusa sands?**
  Foxhill water is not a major issue, except for exacerbation of anhydrite dissolution. This sustains calcium concentration at equilibrium.
Issues specific to Minnelusa

- Most reservoirs contain measurable fractions of calcium sulfate in the form of anhydrite.
- Water source typically employed ranges in salinity from 100’s to less than 2000 ppm, which leads to dissolution of anhydrite.
- As a result, salinity can be low, but calcium concentration can be high.
Low-salinity conditions complicates attainment of optimum salinity, which can be mitigated with the use of alkali.

Inexpensive alkalis will tend to precipitate and high-pH conditions can accelerate anhydrite dissolution.
MINNELUSA ASP EXAMPLE
Parameter
• Salinity
• Surfactant blend ratio
• Soap/surfactant ratio

Winsor Type - I
Winsor Type - II
Winsor Type - III

Optimal parameter

Brine + surfactant
Pipette (bottom sealed)

Initial interface

Oil

24 hr
Materials and Methods

- Constate brine

<table>
<thead>
<tr>
<th>Component</th>
<th>Wt (gr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MgSO₄</td>
<td>0.313</td>
</tr>
<tr>
<td>KCl</td>
<td>0.136</td>
</tr>
<tr>
<td>CaCl₂.2H₂O</td>
<td>1.676</td>
</tr>
<tr>
<td>NaCl</td>
<td>0.697</td>
</tr>
<tr>
<td>Na₂SO₄</td>
<td>4.661</td>
</tr>
<tr>
<td>TDS</td>
<td>7100 ppm</td>
</tr>
</tbody>
</table>

- Injection brine

Only 1600 ppm NaCl
Materials and Methods

<table>
<thead>
<tr>
<th>DC Crude Oil</th>
<th>Viscosity at 48°C = 83 cP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surfactant</td>
<td>0.75wt%PS13-D + 0.25wt%PS3B</td>
</tr>
<tr>
<td>Polymer</td>
<td>Flopaam-3330s</td>
</tr>
<tr>
<td></td>
<td>2000 ppm (ASP)</td>
</tr>
<tr>
<td></td>
<td>1000 ppm (P)</td>
</tr>
<tr>
<td>Alkali</td>
<td>1wt% NaOH</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Core</th>
<th>Berea: (ASP 1)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>L= 7.904 cm</td>
</tr>
<tr>
<td></td>
<td>D= 3.73 cm</td>
</tr>
<tr>
<td></td>
<td>PV= 22.12 cc</td>
</tr>
<tr>
<td></td>
<td>Φ= 25.62%</td>
</tr>
<tr>
<td></td>
<td>K_{air}= 366.9 md</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Minnelusa: (ASP 2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>L= 7.017 cm</td>
</tr>
<tr>
<td>D= 3.728 cm</td>
</tr>
<tr>
<td>PV= 16.41 cc</td>
</tr>
<tr>
<td>Φ= 21.43%</td>
</tr>
<tr>
<td>K_{air}= 808.2 md</td>
</tr>
</tbody>
</table>
Results (ASP#1: Model Rock)
Results (ASP#2: Minnelusa Rock)
Observed precipitation at effluent samples:

As we expected some secondary minerals was produced (here calcite, also some sulfur was produced which is a really evidence for anhydrite dissolution)
MITIGATION OF ANHYDRITE DISSOLUTION
Mitigation of Anhydrite Dissolution
Mitigation of Anhydrite Dissolution

Kazempour et al., 2012, 2013

Model Rock

Anhydrite-Rich Rock

Traditional Design

Designed Brine
MINNELUSA ASP/SP AT HIGH TEMPERATURE
## TC formation brine composition (25°C)

<table>
<thead>
<tr>
<th>Ions</th>
<th>Concentration (mg/lit)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Na⁺</td>
<td>35,545</td>
</tr>
<tr>
<td>Ca²⁺</td>
<td>1,124</td>
</tr>
<tr>
<td>Mg²⁺</td>
<td>328</td>
</tr>
<tr>
<td>SO₄²⁻</td>
<td>3,309</td>
</tr>
<tr>
<td>Cl⁻</td>
<td>54,200</td>
</tr>
<tr>
<td>pH</td>
<td>7</td>
</tr>
<tr>
<td>TDS</td>
<td>94,506</td>
</tr>
</tbody>
</table>
Calcium mineral saturation ratio of TC brine (25°C < T < 71°C)
### Phase-behavior (coarse screening)

- TC crude oil
- Aqueous: 0.5wt% surfactant + 50% diluted TC brine

<table>
<thead>
<tr>
<th>Surfactant</th>
<th>Bulk</th>
<th>Precipitation</th>
<th>Phase-behavior</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surf1</td>
<td>Cloudy</td>
<td>+</td>
<td>OK</td>
</tr>
<tr>
<td>Surf2</td>
<td>Cloudy</td>
<td>+</td>
<td>OK</td>
</tr>
<tr>
<td>Surf3</td>
<td>Cloudy (not very)</td>
<td>-</td>
<td>OK</td>
</tr>
<tr>
<td>Surf4</td>
<td>Clear (but not 100%)</td>
<td>-</td>
<td>OK</td>
</tr>
<tr>
<td>Surf5</td>
<td>Cloudy</td>
<td>-</td>
<td>Not satisfactory</td>
</tr>
<tr>
<td>Surf6</td>
<td>Cloudy</td>
<td>-</td>
<td>OK</td>
</tr>
</tbody>
</table>
➢ TC crude oil
➢ Aqueous: 0.5wt% surfactant + 50% diluted TC brine
Phase-behavior results

Surf. 3 (1wt%)- at 71°C (Stability test)

NaCl increases (ppm)

Aqueous phase is Cloudy (but no precipitation)
<table>
<thead>
<tr>
<th>NaCl Increases (ppm)</th>
<th>Initial Interface</th>
<th>Opt. Salinity Range (σ &gt; 10)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>20K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>30K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>40K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>50K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>60K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>70K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>80K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>90K</td>
<td></td>
<td></td>
</tr>
<tr>
<td>100K</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Effect of hardness (Ca$^{2+}$ and Mg$^{2+}$)

Surf. 4 (1wt%) - at 71°C

NaCl conc. = 70K ppm

- **Sample 1**
  - Ca$^{2+}$ = 600 ppm
  - Mg$^{2+}$ = 200 ppm

- **Sample 2**
  - Ca$^{2+}$ = 1200 ppm
  - Mg$^{2+}$ = 600 ppm

Initial interface
Effect of alkali
Surf. 4 (1wt%) + Na4EDTA.2H2O (1.1wt%) - at 71°C

Initial interface

Opt. salinity range (σ>10)
Surf. 4 (1wt%) + NaBO2.H2O (1wt%) - at 71 C

---

NaCl increases (ppm) ---

10K 20K 30K 40K 50K 60K 70K 80K 90K 100K

Initial interface

---

Opt. salinity range
(σ>10)
Surf. 4 (1wt%) + NaBO2.H2O (1wt%) - at 71 C

<table>
<thead>
<tr>
<th>NaCl increases (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10K</td>
</tr>
</tbody>
</table>

Initial interface
Effect of hardness ($\text{Ca}^{2+} \text{ and } \text{Mg}^{2+}$)

Surf. 4 (1wt%) + NaBO2.H2O (1 wt%) - at 71 C

- **NaCl conc.** = 70K ppm
  - **Sample 1**
    - $\text{Ca}^{2+}$ = 600 ppm
    - $\text{Mg}^{2+}$ = 200 ppm
  - **Sample 2**
    - $\text{Ca}^{2+}$ = 1200 ppm
    - $\text{Mg}^{2+}$ = 600 ppm

Initial interface
Surf. 4 (1wt%) + NaOH (1wt%) - at 71 C

Opt. salinity range ($\sigma > 10$)
Surf. 4 (1wt%) + NaOH (1wt%) - at 71 C

NaCl increases (ppm)

Initial interface
Surf. 4 (1wt%) + NaOH (0.3wt%) + Na2SO4 (29.58gr/lit) - at 71 C

Opt. salinity range ($\sigma$ > 10)
Effect of hardness (Ca$^{2+}$ and Mg$^{2+}$)

Surf. 4 (1wt%) + NaOH (0.3wt%) + Na$_2$SO$_4$ (29.58gr/lit) - at 71°C

NaCl conc. = 70K ppm

- Sample 1
  - Ca$^{2+}$ = 600 ppm
  - Mg$^{2+}$ = 200 ppm
- Sample 2
  - Ca$^{2+}$ = 1200 ppm
  - Mg$^{2+}$ = 600 ppm
Effect of surfactant concentration↓
Surf. 4 (0.5wt%) - at 71°C

NaCl increases (ppm)

Initial interface

Opt. salinity range ($\sigma > 10$)
Effect of hardness (Ca$^{2+}$ and Mg$^{2+}$)

Surf. 4 (0.5wt%) - at 71 C

NaCl conc. = 70K ppm
- Sample 1
  - Ca$^{2+}$ = 600 ppm
  - Mg$^{2+}$ = 200 ppm
- Sample 2
  - Ca$^{2+}$ = 1200 ppm
  - Mg$^{2+}$ = 600 ppm

Initial interface
Rheological behavior of different SP blends varying water chemistry

(1wt% Surf. 4 +2,250 ppm Flopaam 3330s at 71 °C)

 Ionic strength increases
Rheological behavior of SP blend & chasing polymer at 71 °C

- **Injected SP:**
  - 1wt% Surf. 4 + 2,250 ppm Flopaam 3330S prepared in injected water (IW)

- **Injected chasing polymer (P):**
  - 1,000 ppm Flopaam 3330S prepared in injected water (IW)
Water composition during different flooding steps

<table>
<thead>
<tr>
<th>Waters</th>
<th>Connate water (CW)</th>
<th>Water flooding (WF)</th>
<th>Injected water (IW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ions</td>
<td>Concentration (mg/lit)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Na⁺</td>
<td>35,545</td>
<td>29,363</td>
<td>17,698</td>
</tr>
<tr>
<td>Ca²⁺</td>
<td>1,124</td>
<td>955.4</td>
<td>627</td>
</tr>
<tr>
<td>Mg²⁺</td>
<td>328</td>
<td>278.8</td>
<td>162</td>
</tr>
<tr>
<td>SO₄²⁻</td>
<td>3,309</td>
<td>2,812.7</td>
<td>2,876</td>
</tr>
<tr>
<td>Cl⁻</td>
<td>54,200</td>
<td>46,070</td>
<td>25,085</td>
</tr>
<tr>
<td>pH</td>
<td>7</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>TDS</td>
<td>94,506</td>
<td>80,330</td>
<td>46,448</td>
</tr>
</tbody>
</table>
First chemical flooding condition

- Flow rate: 0.5 cc/min
- Confining pressure: 2,000 psi
- Back-pressure: 1,500 psi
- Temperature: 71 °C
- Utilized core: core 104-b
  - Contains anhydrite
  - L = 6.671 cm and D = 3.805 cm
  - Porosity = 16.2% and PV = 14.13 cc
  - $K_{air} = 139$ mD
- Flooding steps:
  1. Aging the core in connate brine (TDS = 95K) for one week at above conditions and then measuring brine permeability ($Sw = 1$)
  2. Establishing $Sw_i$ by injecting TC crude oil and then aging the core for one more week for any possible of wettability alteration in presence of crude oil
  3. Measuring oil permeability at $Sw_i$ at the end of aging period
  4. 8 PV injection of WF brine in secondary mode (TDS = 80K)
  5. Measuring water permeability at $Sor$
  6. 1 PV injection of SP blend prepared in IW (TDS = 46K)
  7. 1 PV injection of P solution prepared in IW (TDS = 46K)
  8. 3 PV injection of WF brine (TDS = 80K) in the post-brine flooding mode
Core 104-b (anhydrite distribution)
Primary results of first coreflooding

- WF
- SP flood
- P flood
- Post-WF

Looks very promising
Summary

- Low salinity conditions in Minnelusa reservoirs under fresh water flooding can be addressed with proper ASP design.
- Issues associated with anhydrite dissolution can be dealt with proper water strategy and understanding of geochemical effects.
- High-salinity, higher temperature reservoirs are better targets for SP designs, which alleviates the need for high-quality water.