Field B Water flooding Optimization
Project in Progress

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Objective

Laboratory Evaluation of Injecting Designed Water to Improve Waterflood Oil Recovery in Field B Cores
Recovery Mechanisms for Designed Waterflooding
Physically-chemically

composition
(asphaltenes, R-COO-)

Sor

Oil

Injected water
chemistry
injection rate
Injection sequence

Water

Test Conditions

Sw

Rock

mineralogy
heterogeneity

ENHANCED OIL RECOVERY INSTITUTE
Laboratory Evaluation

- Spontaneous imbibition – important oil recovery mechanism for fractured reservoirs
- Waterflooding – direct observation of oil recovery improvement in lab
Procedures

- **Data Collection / Literature review**
  - Field B field information
  - Available core / crude oil / formation water data

- **Evaluation and Analysis**
  - Formation water geochemistry → Synthetic brine → Designed water
  - Core description / mineralogy analysis
  - Routine core analysis
  - Spontaneous imbibition / Waterflooding
Well Locations
Reservoir Conditions

- Discovered in 1944, structural trapping
- Average Depth = 3400 ft
- Initial OWC = 1085 ft above sea level
- Main Pay Zone: Phosphoria - Permian
- Average Pay Thickness ~ 15 ft
- Pi = 1520 psi
- Pb = 200 psi
- GOR = 30 SCF/Bbl;
- Initial FVF = 1.01 Bbl/Bbl
- Reservoir Temperature = 112°F
- Rw highly variable
- Fair Continuity through Fractures
- Lithology: Dolomite with chert, anhydrite and red shale
Oil Production

- **Original Oil in Place:** 6.549 MMBO
- **Ultimate Primary (Decline Curve Analysis):**
  - 0.544 MMBO (8.3% OOIP)
- **Up to Date (10/2012) Recovery (primary + waterflooding since 1968):**
  - 1.854 MMBO (28.32% OOIP)
- **Waterflood Oil Recovery Up to Date (10/2012):**
  - 1.31 MMBO (20% OOIP)
- **Remaining Oil:** 4.695 MMBO
- **High Current WOR:** up to 27 Bbl/Bbl (~ 96% water-cut)
Core Analysis Data

- Average Porosity ~ 13.3% (10-22% by log)
- Average Matrix Permeability ~ 2.4 md
- Fracture Permeability > 1000 md
- Effective Oil Perm Ko ~ 40 md
- Connate Water Saturation Swi ~ 40%

Crude Oil Analysis Results

\[ \mu_o \text{@reservoir T&P} = 32 \text{ cP} \]
\[ \gamma_o = 20 - 23^\circ \text{API} \]
C10+ in oil > 92 wt% (composition analysis)
Geochemistry Analysis

The diagram illustrates the geochemical analysis of aqueous solutions at 45°C, focusing on the concentrations of calcium and sulfate ions. Key points labeled include:

- **Calcite** region
- **Gypsum** region
- **Aqueous** region

Points indicating different dilution and concentration scenarios:

- Initial Brine Recipe
- 10x Dilution
- 10x Dilution + 9.26g Na₂SO₄
- Half SO₄⁻⁻
- No HCO₃⁻⁻
### Available Core Material

<table>
<thead>
<tr>
<th>Sample #</th>
<th>Well  #</th>
<th>Depth, ft</th>
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<tbody>
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<td>3411.2</td>
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<tr>
<td>KC22-3411-H-2</td>
<td>22</td>
<td>3411.5</td>
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<tr>
<td>KC22-3411-H-3</td>
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<td>KC22-3412-H-1</td>
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Well #22: an injector with low injectivity
Well #27: a producer and was shut in due to high water cut
Field B Petrology Study

- Core Description (macro-scale)
- Thin Section Analysis (micro-scale)
- X-Ray Diffraction (XRD) (physical-chemical make-up of the rock)
- Scanning Electron Microscope (SEM) (mineral & pore structure)
- BET Method for Surface Area
Field B #22 Thin Sections

- Primary anhydrite
- Secondary anhydrite
- Fluorite
- Pyrite
Field B #27 Thin Sections

Quartz

Pyrite

Fluorite
Mineralogy – Field B vs. Field C

Field B
- Crystalline dolostone and patchy and nodulal anhydrite (pore filling)

Field C
- Crystalline dolomite and patchy anhydrite
Preparation for Spontaneous Imbibition & Waterflooding

- Core Selection (CT scan for heterogeneity)
- Water Saturation
- Water Permeability Measurements (net confining P)
- Establishment of initial Water Saturation $S_{wi}$ (porous plate)
- Oil Saturation @ $S_{wi}$
- Crude Oil Aging at Reservoir Temperature
## Comparison of Porosity and Permeability

<table>
<thead>
<tr>
<th>Core ID</th>
<th>Depth (ft)</th>
<th>Permeability, md</th>
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<tr>
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<td>Brine</td>
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</table>

- **NCS\text{gas} = 800 \text{ psi}**
- **NCS\text{brine} = 1350 \text{ psi}**
Examples of Low Salinity Waterflooding for Carbonate Cores

• Field C Dolomite
• Field D Limestone
Low Salinity Waterflooding Lab Tests
- Field C Core

Oil recovery, % OOIP

Dimensionless imbibition time

Strongly water wet (Ma et al., 1997)

Cottonwood Creek Core
Phi = 0.11
Kg = 6.6 md
Swi = 34.5%
Low Salinity Waterflooding – Field C P1

P1

- $K_g = 6.8$ md, $\phi = 9.5\%$
- $S_{wi} = 22.7\%$

$K_{we1} = 2.1$ md

$K_{we2} = 1.1$ md

PW

30,755 ppm

5% PW dilute

1,537 ppm

Pressure drop, psi

Oil recovery, % OOIP
Low Salinity Waterflooding – Cottonwood Core P2

\[ K_g = 293.9 \, \text{md}, \, \phi = 19.6\% \]
\[ S_{wi} = 23.1\% \]

Pressure drop, psi

Oil recovery, % OOIP

K\textsubscript{we} = 9.4 \, \text{md}

Brine injected, PV

PW 30,755 ppm

5% PW dilute 1,537 ppm

\[ \pm 5.5\% \]
Composite core:

- $\phi = 25.1\%$
- $K_{brine} = 39.6$ md
- $S_{wi} = 10.5\%$
Recovery Mechanisms for Low Salinity Waterflooding for Limestone and Chalk

- Wettability Alteration (Increase spontaneous imbibition rate)
Possible Mechanisms for Low Salinity Waterflooding
- Field B Phosphoria Formation

- Wettability Alteration
Potential Mechanisms for Low Salinity Waterflooding
- Field B Phosphoria Formation (cont.)

- Dissolution of anhydrite

Tensleep sandstone before and after flow of low salinity water (Lebedeva et al, 2009)
Work in Progress...

- Oil Phase Permeability $K_0$ Measurements
- Spontaneous Imbibition to Test Wettability
  - Spontaneous imbibition in syn formation water
  - Spontaneous imbibition in designed water
  - Spontaneous imbibition in surfactant solution
- Waterflooding
  - Waterflooding with syn formation water
  - Waterflooding with designed water
  - Waterflooding with surfactant solution
- Results and Analysis
- Discussion with Operators
Thank You!