Minnelusa Advanced Core Analysis and Evaluation Project

Collaborative work of EORI with The Minnelusa Consortium and C&PE faculty members, Professors:

Alvarado, Morrow and Piri

Prepared for The EOR Commission and Technical Advisory Board Meeting

Reza Barati

07/24/2013
Outline

• Introduction & Background
• Objectives
• Core protocol
• Thin section analysis
• Water and oil properties
• Wettability index measurement, low salinity and sequential water flooding

• Relative permeability measurements
• Capillary pressure measurements
• Summary
• Future work
• Acknowledgements
Introduction

• Core was collected from a Minnelusa well
• 120 ft of core was collected, ~58 ft of which was from Minnelusa (B sand)
• 83 core plugs were taken, 20 of which were sent by the company for cleaning and porosity and permeability measurements
• Core was slabbed and described by the company
• The slabbed part of the core is donated to the Geology and Geophysics Dept. at UW and the rest is donated to EORI
• 83 core plugs were also donated to EORI
Background

Water saturation calculation, Archie’s equation:

$$S_w = \left[ \frac{\phi R_w}{\phi m R_t} \right]^{1/n}$$

Table 1 Electrical properties of the Minnelusa B-sand, Hawk Point Field [James et al., 1989].

<table>
<thead>
<tr>
<th>No. 31–30 Ickes</th>
<th>Cementation Exponent</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure, psi</td>
<td>“a”</td>
<td>“m”</td>
<td></td>
</tr>
<tr>
<td>0</td>
<td>1.00</td>
<td>1.59</td>
<td></td>
</tr>
<tr>
<td>400</td>
<td>1.00</td>
<td>1.69</td>
<td></td>
</tr>
<tr>
<td>7230</td>
<td>1.00</td>
<td>1.84</td>
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</table>

<table>
<thead>
<tr>
<th>No. 42–30 Ickes</th>
<th>Cementation Exponent</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure, psi</td>
<td>“a”</td>
<td>“m”</td>
<td></td>
</tr>
<tr>
<td>0</td>
<td>1.00</td>
<td>1.65</td>
<td></td>
</tr>
<tr>
<td>400</td>
<td>1.00</td>
<td>1.70</td>
<td></td>
</tr>
<tr>
<td>7175</td>
<td>1.00</td>
<td>1.82</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Saturation Exponent (Ambient Pressure)</th>
<th>Depth</th>
<th>“n”</th>
</tr>
</thead>
<tbody>
<tr>
<td>11418–11419</td>
<td>1.50</td>
<td></td>
</tr>
<tr>
<td>11421–11422</td>
<td>1.46</td>
<td></td>
</tr>
<tr>
<td>11421–11422</td>
<td>1.62</td>
<td></td>
</tr>
<tr>
<td>11427–11428</td>
<td>1.55</td>
<td></td>
</tr>
</tbody>
</table>

Composite 1.53

<table>
<thead>
<tr>
<th>Saturation Exponent (Ambient Pressure)</th>
<th>Depth</th>
<th>“n”</th>
</tr>
</thead>
<tbody>
<tr>
<td>11356–11357</td>
<td>1.26</td>
<td></td>
</tr>
<tr>
<td>11359–11360</td>
<td>1.33</td>
<td></td>
</tr>
<tr>
<td>11364–11365</td>
<td>1.08</td>
<td></td>
</tr>
<tr>
<td>11374–11375</td>
<td>1.15</td>
<td></td>
</tr>
</tbody>
</table>

Composite 1.20
Background, cont’d

• Petrography [James, 1989]:
  – Well-rounded, well-sorted, and equant quartz grains, with lesser amounts of feldspar.
  – Dominant diagenetic minerals are anhydrite and dolomite with lesser quantities of clays, quartz, and pyrite.

• Electrical properties:
  – Cementation exponent (m): Represents pore variations caused by differential anhydrite dissolution, dolomite cementation, and compaction.

• Saturation exponent (n): Values larger than 2 are documented for oil-wet and mixed-wettability cores, in which oil preferentially wets grain and crystal surfaces, by decreasing conductivity.
Background, cont’d

- $P_c = P_c$ (pore size, pore distribution, pore geometry, fluid saturation, saturation history, wettability, and IFT)
- Relative permeability = $f$ (fluid saturation, fluid saturation history, wettability, injection rate, viscosity ratio, interfacial tension, pore structure, temperature and heterogeneity)
- Measurement of electrical properties, wettability, relative permeability and capillary pressure curves is essential using reservoir fluids and at reservoir pressure and temperature
Objectives

- Improve the geological model of this field by measuring rock properties like porosity and permeability
- Generate Special Core Analysis (SCAL) for core plugs representative of different observed lithofacies for this well to improve reservoir descriptions and simulations for this field and other Minnelusa fields
- Evaluate future application of EOR/IOR in this field and other Minnelusa fields
Core Analysis Protocol

- Core plugs scanned
- Thin section analysis
- Cleaning the plugs:
  - 6 plugs were flushed and extraction was used for the rest
- Selection of core plug triplicates for different lithofacies (three)

- Core plugs representative of different lithofacies distributed between the groups
- Core plugs saturated and aged in brine for 10 days
- Oil flood to establish irreducible water saturation
- Age at 94 °C for 30 days
Core Analysis Protocol, cont’d

- Steady-state relative permeability measurements:

- Pore network modeling

- Capillary pressure measurements:
  - Pc for low salinity and high salinity floods
  - AP, ASP and A blends for EOR core flooding tests
  - Optimize the use of alkali to reduce precipitation of scales

- Wettability characterization by spontaneous imbibition
  - Anhydrite dissolution effect on water flooding
  - Unsteady-state relative permeability
Thin Section Analysis

Anhydrite cemented SS (#1-110, $k_{He}=0.225$ mD, $\phi=7.7\%$)

Anhydrite nodules (#1-83)

Fig.1 Thin section analysis done by Peigui Yin: The LHS image shows the anhydrite cemented SS and the RHS image shows the anhydrite nodules observed in some core plugs. Black spots are oil stained dolomite cement.
Thin Section Analysis, cont’d

Dolomite cement (#1-64, $k_{He}=0.069$ mD, $\phi=3.5\%$)

Sandy dolomite (#1-63)

Fig.2 Thin section analysis done by Peigui Yin: The LHS image shows the sandstone with dolomite cement and the RHS image shows the sandy dolomite observed in some core plugs.
Fig. 3 Thin section analysis done by Peigui Yin: A permeable SS observed in some of the core plugs

Permeable SS (#1-74, k_{He}=280.5 mD, \( \phi = 23.7\% \))
Thin Section Analysis, cont'd
Porosity and Permeability Measurements

Fig. 5 Gas porosity and permeability (Morrow’s group) and shifter sonic log vs. depth

Fig. 6 a) Porosity-average CT# correlations for 20 cleaned core plugs (red squares) and 53 uncleaned core plugs (green triangles). b) Core porosity vs. sonic transit time (Piri’s group)
Water Properties

Table 2 Water composition of the produced brine and the brine used in the experiments.

<table>
<thead>
<tr>
<th>Cations and anions</th>
<th>Water analysis report (mg/L)</th>
<th>Used in the experiments (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Na</td>
<td>17646</td>
<td>20805.9</td>
</tr>
<tr>
<td>K</td>
<td>756.1</td>
<td>756.1</td>
</tr>
<tr>
<td>Ca</td>
<td>626.8</td>
<td>626.8</td>
</tr>
<tr>
<td>Mg</td>
<td>162.2</td>
<td>162.2</td>
</tr>
<tr>
<td>Ba</td>
<td>0.22</td>
<td>0</td>
</tr>
<tr>
<td>Sr</td>
<td>19.2</td>
<td>19.2</td>
</tr>
<tr>
<td>Fe</td>
<td>32.3</td>
<td>0</td>
</tr>
<tr>
<td>Mn</td>
<td>0.13</td>
<td>0</td>
</tr>
<tr>
<td>Si</td>
<td>44.6</td>
<td>0</td>
</tr>
<tr>
<td>SO₄</td>
<td>2876.1</td>
<td>2876.1</td>
</tr>
<tr>
<td>Cl</td>
<td>34769</td>
<td>32244.9</td>
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<tr>
<td>HCO₃</td>
<td>558.8</td>
<td>0</td>
</tr>
<tr>
<td>TDS</td>
<td>57491.2</td>
<td>57491.2</td>
</tr>
<tr>
<td>pH</td>
<td>7</td>
<td>7.42</td>
</tr>
</tbody>
</table>

Table 3 Brine density, viscosity and surface tension measured at 60 °C (Morrow’s group)

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (g/cm³)</td>
<td>1.0244</td>
</tr>
<tr>
<td>Viscosity, cP</td>
<td>0.55</td>
</tr>
<tr>
<td>Surface tension, mN/m</td>
<td>70.2</td>
</tr>
<tr>
<td>IFT against crude oil, mN/m</td>
<td>20.3</td>
</tr>
</tbody>
</table>
Crude Oil Properties

Table 4 Asphaltene content of the crude oil (Piri’s group)

<table>
<thead>
<tr>
<th>Sample No.</th>
<th>Crude oil (gr)</th>
<th>n-heptane (cc)</th>
<th>Asphaltene content of crude oil (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.00</td>
<td>40</td>
<td>6.57</td>
</tr>
<tr>
<td>2</td>
<td>1.00</td>
<td>40</td>
<td>6.43</td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td></td>
<td>6.50</td>
</tr>
</tbody>
</table>

Table 5 Crude oil density, viscosity and surface tension measured at 60 °C (Morrow’s group)

<table>
<thead>
<tr>
<th></th>
<th>Density (g/cm³)</th>
<th>Viscosity, cP</th>
<th>Surface tension, mN/m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density</td>
<td>0.8787</td>
<td>9.59</td>
<td>26</td>
</tr>
</tbody>
</table>

Fig. 7 Crude oil viscosity versus shear rate at 25-95 C (Alvarado’s group)
Spontaneous and Forced Imbibition, Low Salinity Water-Flooding, Sequential Water-Flooding, Anhydrite Solubility and Wax Deposition Studies

Norm Morrow
Nina Loahardjo
Winoto
Carol Robinson (admin.)
(PSC Group, Dept. Chem. and Pet. Eng.)
# Core Plugs Received by Morrow’s Group

## Table 6 Summary of core plug properties received by Morrow’s group

<table>
<thead>
<tr>
<th>Core ID</th>
<th>Kg</th>
<th>Anhydrite content</th>
<th>Test</th>
<th>Condition</th>
</tr>
</thead>
<tbody>
<tr>
<td>86B</td>
<td>~120 mD</td>
<td>none (or very low)</td>
<td>Imbibition; waterflood</td>
<td>cleaned</td>
</tr>
<tr>
<td>79B</td>
<td>~100 mD</td>
<td>none (or very low)</td>
<td>Imbibition</td>
<td>as-is/not-cleaned</td>
</tr>
<tr>
<td>84B</td>
<td>~150 mD</td>
<td>low, spotty</td>
<td>Imbibition</td>
<td></td>
</tr>
<tr>
<td>63</td>
<td>&lt;0.005 mD</td>
<td>spotty</td>
<td>low perm</td>
<td></td>
</tr>
<tr>
<td>83</td>
<td>~5 mD</td>
<td>spotty</td>
<td>low perm</td>
<td></td>
</tr>
<tr>
<td>93B</td>
<td>0.5 mD</td>
<td>as cementation</td>
<td>low perm</td>
<td>cleaned</td>
</tr>
<tr>
<td>113</td>
<td>50 mD</td>
<td>no (or very low)</td>
<td>CT- scan; brine flush</td>
<td></td>
</tr>
<tr>
<td>116B</td>
<td>22 mD</td>
<td>spotty</td>
<td>CT- scan; brine flush</td>
<td></td>
</tr>
<tr>
<td>End pieces: 73V, 112B, 116B, 110, 63</td>
<td>&lt;0.1 to 9 mD</td>
<td>low, spots, and high cementation</td>
<td>Micro X-ray CT</td>
<td></td>
</tr>
</tbody>
</table>
Variation of Anhydrite Content During Water-Flooding

Core113  
original core  

after high salinity brine flush  

after low salinity brine flush (ongoing)

Permeability (Klink) =

27.0 mD  

36.3 mD  

43.6 mD
### Crude Oil and Brine Properties

Table 7 Summary of crude oil and brine properties (Morrow’s group)

<table>
<thead>
<tr>
<th>Properties</th>
<th>20°C</th>
<th>60°C</th>
<th>95°C (extrapolated)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil refractive index</td>
<td>0.5180</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil density (g/cm³)</td>
<td>0.9024</td>
<td>0.8787</td>
<td>0.8565</td>
</tr>
<tr>
<td>Oil viscosity (cP)</td>
<td>41.4</td>
<td>9.59</td>
<td>3.0</td>
</tr>
<tr>
<td>Oil surface tension (mN/m)</td>
<td>28.7</td>
<td>26.0</td>
<td></td>
</tr>
<tr>
<td>Oil/brine interfacial tension</td>
<td>17.3</td>
<td>20.3</td>
<td>22.9</td>
</tr>
<tr>
<td>Brine density</td>
<td>1.0381</td>
<td>1.0244</td>
<td>1.0124</td>
</tr>
<tr>
<td>Brine viscosity</td>
<td>1.06</td>
<td>0.55</td>
<td>0.40</td>
</tr>
<tr>
<td>Brine surface tension (mN/m)</td>
<td>73.7</td>
<td>70.2</td>
<td></td>
</tr>
</tbody>
</table>
**Wettability Index Measurements**

**Fig. 8 Wettability index measurement procedure (Morrow’s group)**

**Table 8 Wettability index measurement results (Morrow’s group)**

<table>
<thead>
<tr>
<th></th>
<th>Core 86b</th>
<th>Core 84b</th>
<th>Core 79b</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Initial condition</strong></td>
<td>cleaned</td>
<td>uncleaned</td>
<td>uncleaned</td>
</tr>
<tr>
<td><strong>Dry properties</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>porosity (by helium)</td>
<td>18.6%</td>
<td>12.3%</td>
<td>12.3%</td>
</tr>
<tr>
<td>Klinkenberg permeability @20°C</td>
<td>117.4 mD</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Brine-saturated properties:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>porosity</td>
<td>16.2%</td>
<td>10.5%</td>
<td></td>
</tr>
<tr>
<td>permeability @20°C</td>
<td>111.5 mD</td>
<td>2.0 mD</td>
<td></td>
</tr>
<tr>
<td><strong>Oil-saturated properties:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>porosity</td>
<td></td>
<td></td>
<td>12.6%</td>
</tr>
<tr>
<td>permeability @20°C</td>
<td></td>
<td></td>
<td>~6.5-7.9 mD</td>
</tr>
<tr>
<td><strong>Initial-water properties:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$S_{wi}$</td>
<td>20.5%</td>
<td>18.8%</td>
<td>~0%</td>
</tr>
<tr>
<td>oil permeability @20°C</td>
<td>~20-42 mD</td>
<td>5.8 mD</td>
<td>~6.5-7.9 mD</td>
</tr>
<tr>
<td>oil permeability @60°C</td>
<td>~65-85 mD</td>
<td>~6.0-7.2</td>
<td>~17-25 mD</td>
</tr>
<tr>
<td><strong>Imbibition test:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>oil produced during imbibition</td>
<td>2.05 cm³</td>
<td>2.00 cm³</td>
<td>2.35 cm³</td>
</tr>
<tr>
<td>oil produced during waterflood</td>
<td>5.65 cm³</td>
<td>2.55 cm³</td>
<td>6.30 cm³</td>
</tr>
<tr>
<td>index ($I_w$)</td>
<td>0.27</td>
<td>0.44</td>
<td>0.27</td>
</tr>
<tr>
<td><strong>Dry properties:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>porosity (by helium)</td>
<td>18.3%</td>
<td>17.2%</td>
<td>17.5%</td>
</tr>
<tr>
<td>Klinkenberg permeability @20°C</td>
<td>124.1 mD</td>
<td>154.2 mD</td>
<td>108.0 mD</td>
</tr>
</tbody>
</table>

**Fig. 8 Wettability index measurement procedure (Morrow’s group)**

1. Core 86b received solvent-cleaned core.
2. Core 84b received uncleaned/as is.
3. Core 79b received solvent-cleaned core.
4. Measure dry properties.
5. Saturate with brine; pressurize to 1000 psi with brine for 2+ hours; soak in brine for 10 days @95°C & ±15 psig; cool to room temperature; measure brine-saturated properties.
6. Saturate with oil; pressurize to 1000 psi with oil for 12+ hours; age with crude oil at 95°C & ±1000 psig for 30+ days; cooled to 60°C then set for imbibition; heated to 95°C for imbibition (2 months); cooled to 60°C then waterflood for about 90cm³ at 2 cm³/min.
7. Solvent-clean with alternating toluene and methanol flooding until effluent is clear (very light yellow tint is possible after 20 PV flooding but accepted as clear enough).
8. Measure dry properties.
Wettability Index Measurements, cont’d

\[ t_D = \frac{2}{L c^2} \frac{K}{\rho \mu_w} \left( \frac{\sigma}{\mu_o \mu_w} \left( 1 + \frac{\mu_o}{\mu_w} \right) \right) \]

\[ I_w = 0.44 \quad I_w = 0.27 \]

Fig. 9 Oil recovery caused by spontaneous imbibition versus dimensionless time (Morrow’s group)

Fig. 10 Oil recovery caused by forced imbibition and pressure drop versus PV of injected brine (Morrow’s group)
Enhanced Oil Recovery Institute

Core 86b
Core 84b
Core 79b

Measure dry properties
Saturate with brine; pressurize to 1000 psi with brine for 2+ hours; soak in brine for 10 days @95°C & ±15 psig; cool to room temperature; measure brine-saturated properties;

Saturate with oil; pressurize to 1000 psi with oil for 12+ hours cooled to 60°C then set for imbibition; heated to 95°C for imbibition (2 months); cooled to 60°C then waterflood for about 90 cm³ at 2 cm³/min

Secondary waterflood with brine; tertiary waterflood with 20x diluted brine; re-establish Swi by oil flooding and re-waterflood with diluted brine (5 consecutive times)

Solvent clean with alternating toluene and methanol flooding until effluent is clear (very light yellow tint is possible after 20 PV flooding but accepted as clear enough)

Measure dry properties

Initial condition:

Dry properties:
- Porosity (by helium)
- Klinkenberg permeability @20°C

Brine-saturated properties:
- Porosity
- Permeability @20°C

Oil-saturated properties:
- Porosity
- Permeability @20°C

Initial-water properties:
- Swi
- Oil permeability @20°C
- Oil permeability @60°C

Waterflood test:
- Oil produced during secondary WF
  - S_{or,SWF1} \rightarrow S_{wi,SWF2}
  - Oil produced during tertiary WF
  - S_{or,SWF2} \rightarrow S_{wi,SWF3}
  - Oil produced during SWF3
  - S_{or,SWF3} \rightarrow S_{wi,SWF4}
  - Oil produced during SWF4
  - S_{or,SWF4} \rightarrow S_{wi,SWF5}
  - Oil produced during SWF5
  - S_{or,SWF5} \rightarrow S_{wi,SWF6}
  - Oil produced during SWF6

Imbibition test:
- Oil produced during imbibition
- Oil produced during waterflood index (I_w)

Table 9 Low salinity and sequential water-flooding results (Morrow’s group)

<table>
<thead>
<tr>
<th>Initial condition:</th>
<th>re-cleaned</th>
<th>cleaned</th>
<th>cleaned</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry properties:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity (by helium)</td>
<td>18.3%</td>
<td>17.2%</td>
<td>17.5%</td>
</tr>
<tr>
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<td>124.1 mD</td>
<td>154.2 mD</td>
<td>108.0 mD</td>
</tr>
<tr>
<td>Brine-saturated properties:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity</td>
<td>17.2%</td>
<td>15.0%</td>
<td>17.4%</td>
</tr>
<tr>
<td>Permeability @20°C</td>
<td>105.0 mD</td>
<td>92.4 mD</td>
<td>~15.4-18.4 mD</td>
</tr>
<tr>
<td>Oil-saturated properties:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity</td>
<td>17.2%</td>
<td>15.0%</td>
<td>17.4%</td>
</tr>
<tr>
<td>Permeability @20°C</td>
<td>105.0 mD</td>
<td>92.4 mD</td>
<td>~15.4-18.4 mD</td>
</tr>
<tr>
<td>Initial-water properties:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Swi</td>
<td>30.0%</td>
<td>23.2%</td>
<td>0%</td>
</tr>
<tr>
<td>Oil permeability @20°C</td>
<td>~19-20 mD</td>
<td>~25-29 mD</td>
<td>~32-33 mD</td>
</tr>
<tr>
<td>Oil permeability @60°C</td>
<td>~31-53 mD</td>
<td>~72-82</td>
<td></td>
</tr>
</tbody>
</table>

Low Salinity and Sequential Water-Flooding Results
Low Salinity and Sequential Water-Flooding, cont’d

Fig. 12 Residual oil saturation after different cycles of sequential waterflooding (Morrow’s group)

Fig. 13 Initial water saturation after different cycles of sequential waterflooding (Morrow’s group)
TC Crude Oil (crossed polars; filtered)

room T → 60°C → 95°C → 60°C → room T

TC Crude Oil (crossed polars; unfiltered)

room T → 60°C → 95°C → 60°C → room T

(all scale bars = 200 μm)
Summary

- Porosity from 3.5% to 23.7% with 60% of the cores with 12-20% porosity.
- Permeability from 0.07-680 mD with average permeability of 77 mD.
- Wettability indexes were measured for a cleaned core and two uncleaned cores and showed weakly water-wet properties.
- Core cleaning as a first step in core restoration may not always be necessary. Amott water index of 0.27 for as supplied cores was also obtained for after cleaning and restoration with TC crude oil.
- After reaching high water cut with high salinity brine, only small incremental oil recovery response was observed upon tertiary low salinity brine injection.
- Positive response was observed for sequential waterflood tests (reduction of residual oil was to 30% of the original residual oil).
- Wax deposition from TC crude oil is not likely to be significant for tests run at 60°C.
Ongoing and Future Work

• Ion analysis after flushing core samples with high salinity water followed by low salinity water, with special attention to production of sulfate ions.
• Low salinity tests for enhanced spontaneous imbibition.
• Micro X-ray CT study for anhydrite dissolution analysis (collaboration with ANU).
• Continue parametric studies of water-flooding and imbibition using TC crude oil
• High resolution CT-scan images of cores after flushing with low salinity brine for anhydrite dissolution test (measurements by courtesy of Chevron).
• Investigation of wax deposition from TC crude oil
• Amott oil index measurements for core plugs from different lithofacies
Pore-scale Characterization &
Core-scale Steady-State
Relative Permeability Measurements

Mohammad Piri
Amir Hossein Alizadeh
Mortaza Akbarabadi
Henry Plancher
Relative Permeability Measurement Setup

Fig. 15 HPHT relative permeability measurement setup. L) HT ovens. M) 2-liter accumulators. R) HT cells and Qizix pumps. (Piri’s group)
Relative Permeability Measurement Setup, cont’d

Fig. 16 HPHT relative permeability measurement setup. L) core flooding setup. M) HT cells and Qizix pumps. R) Back pressure regulator. (Piri’s group)
Relative Permeability Measurements

• Core# 1-100b:
  – $K_{air} = 112$ mD
  – Near zero pressure drop after saturating and aging with brine

• Core#1-98b:
  – $K_{brine} = 95.39$ mD
  – $K_{air} = 69.5$ mD

Fig.17 CT scan image of core#1-100b (Piri’s group)

Fig.18 Water permeability measurement for core#98b (Piri’s group)
High-resolution Microtomography

Sample # 1

- Diameter of images sections = 3mm & 4 mm
- Length of images sections = 3mm & 4 mm
- Resolution = 3 μm & 2 μm
- Approximate porosity = 10.1%
High-resolution Microtomography
High-resolution Microtomography
High-resolution Microtomography
Sample # 2

- Diameter of images sections = 3mm
- Length of images sections = 3mm
- Resolution = 3 μm
- Approximate porosity = 9.5%
High-resolution Microtomography
High-resolution Microtomography
High-resolution Microtomography
Micro-scale core-flooding experiments

- 2D Pore fluid occupancy at the end of oil primary drainage
- Red --- Grains
- Light blue --- Oil
- Dark blue --- Brine
Micro-scale core-flooding experiments

- 3D Pore fluid occupancy at the end of oil primary drainage
- Red --- Grains
- Dark blue --- Oil
- Light green --- Brine
Micro-scale core-flooding experiments

- 3D Pore fluid occupancy at the end of oil primary drainage
- Red --- Grains
- Dark blue --- Oil
- Light green --- Brine
Micro-scale core-flooding experiments

- 2D Pore fluid occupancy at the end of brine imbibition
- Red --- Grains
- Light blue --- Oil
- Dark blue --- Brine
Micro-scale core-flooding experiments

- 3D Pore fluid occupancy at the end of brine imbibition
- Red --- Grains
- Dark blue --- Oil
- Light green --- Brine
Micro-scale core-flooding experiments

- 3D Pore fluid occupancy at the end of brine imbibition
- Red --- Grains
- Dark blue --- Oil
- Light green --- Brine
Micro-scale core-flooding experiments

Individual trapped oil globules at the end of imbibition
Micro-scale core-flooding experiments

Individual trapped oil globules at the end of imbibition
Micro-scale core-flooding experiments

Individual trapped oil globules at the end of imbibition
Summary

• HPHT relative permeability measurement setup was installed and tested

• Aging and primary drainage was performed for one core but not finished
  – One core showed very high permeability after water saturation
  – Uncertainties in gas porosity measurements provided to Piri’s group
Ongoing and Future Work

• Relative permeability measurement for three representative core plugs
• Miniature core floods with ultra-high-resolution micro-tomography of fluid occupancy (in-situ experiments)
Rock Electrical Properties and Capillary Pressure Measurements

Vladimir Alvarado
Xiao Wang
Mahdi Kazempour
Capillary Pressure Measurements - Setup

- The CPCS -355Z Reservoir Condition Capillary Pressure system measures drainage and imbibition capillary pressure in conjunction with electrical resistivity measurements using 2T and 4T electrode configurations at 5 different frequencies.
- The system uses a membrane technique with an upstream oil-wet membrane and a downstream water-wet membrane.
- Confining Pressure: up to 9,950 psi
- Pore Pressure: up to 6,000 psi
- Temperature: up to 150°C
Capillary Pressure Measurements - Procedure

• Pump B is connected to the upstream end to drive oil injection during drainage and pump A controls the downstream pressure
• During imbibition, pump B acts as back-pressure control and pump A injects water from the reservoir

• Resistivity is measured at 100 Hz, 1 kHz, 10 kHz, 20 kHz and 100 kHz and manually collected due to instrumentation problem, so the data will show gaps
• All the pressure and volume data are collected automatically and as frequently as several times a minute
Capillary Pressure Measurements

- Core#1-115:
  - L: 36.68mm
  - D: 37.86mm
  - Absolute Permeability: 66.95mD
  - Porosity: 15.61%
  - Pore Volume: 6.45cc

Table 10 Core characterization

<table>
<thead>
<tr>
<th>Core ID</th>
<th>WY 1-115-#1</th>
<th>WY 1-115-#2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core Type</td>
<td>Minnelusa Core</td>
<td>Minnelusa Core</td>
</tr>
<tr>
<td>Diameter (mm)</td>
<td>37.86</td>
<td>37.86</td>
</tr>
<tr>
<td>Length (mm)</td>
<td>36.68</td>
<td>39.37</td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>70</td>
<td>70</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.15</td>
<td>0.15</td>
</tr>
</tbody>
</table>

Table 11 Experiment conditions

<table>
<thead>
<tr>
<th>Core ID</th>
<th>WY 1-115-#1</th>
<th>WY 1-115-#2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature (°C)</td>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>Back Pressure (psi)</td>
<td>3771</td>
<td>3771</td>
</tr>
<tr>
<td>Confining Pressure (psi)</td>
<td>5000</td>
<td>5000</td>
</tr>
<tr>
<td>Oil</td>
<td>Minnelusa Oil (µ=10cP)</td>
<td>Minnelusa Oil (µ=10cP)</td>
</tr>
<tr>
<td>Connate Water Salinity (ppm)</td>
<td>57,491</td>
<td>57,491</td>
</tr>
<tr>
<td>Injecting Brine Salinity (ppm)</td>
<td>57,491</td>
<td>2,874</td>
</tr>
</tbody>
</table>

Fig.19 CT scan image of core#1-115 (Piri’s group)
Fig. 20 Capillary pressure measurements for cores 1-115#1 and 1-115#2 at reservoir pressure and temperature (Alvarado’s group)
Formation Factor

\[ F = \frac{R_o}{R_w} = \frac{a}{\phi^m} \]

- \( R_o \): resistivity of the rock only filled with brine
- \( R_w \): brine resistivity
- \( m \): cementation exponent

<table>
<thead>
<tr>
<th>Frequency (Hz)</th>
<th>100</th>
<th>1K</th>
<th>10K</th>
<th>20K</th>
<th>100K</th>
</tr>
</thead>
<tbody>
<tr>
<td>F (WY 1-115-#1)</td>
<td>18.54</td>
<td>17.60</td>
<td>17.80</td>
<td>17.91</td>
<td>17.91</td>
</tr>
</tbody>
</table>
Saturation Exponent

- \[ I = \frac{R_t}{R_o} = S_w^{-n} \]
  - I: Resistivity index
  - \( R_t \): Fluid saturated rock resistivity
  - n: Saturation exponent

<table>
<thead>
<tr>
<th>Frequency (Hz)</th>
<th>100</th>
<th>1K</th>
<th>10K</th>
<th>20K</th>
<th>100K</th>
</tr>
</thead>
<tbody>
<tr>
<td>n (Primary Drainage)</td>
<td>1.16</td>
<td>1.56</td>
<td>1.53</td>
<td>1.52</td>
<td>1.51</td>
</tr>
<tr>
<td>n (Imbibition)</td>
<td>1.83</td>
<td>1.80</td>
<td>1.77</td>
<td>1.76</td>
<td>1.74</td>
</tr>
</tbody>
</table>

Table 13 Saturation exponent measured for cores 115-1#1 (Alvarado’s group)

<table>
<thead>
<tr>
<th>Frequency (Hz)</th>
<th>100</th>
<th>1K</th>
<th>10K</th>
<th>20K</th>
<th>100K</th>
</tr>
</thead>
<tbody>
<tr>
<td>n (Primary Drainage)</td>
<td>1.71</td>
<td>1.71</td>
<td>1.70</td>
<td>1.69</td>
<td>1.68</td>
</tr>
</tbody>
</table>
Summary

• Power outage left both imbibition curves unfinished, but there is enough data gathered that we can make some conclusions

• Spontaneous imbibition curve for low salinity injected water showed a significant shift of the zero Pc towards right (moving from a mixed wet state to a more water-wet state).

• Formation factor and saturation exponents have been calculated for both low salinity and high salinity cases.
Ongoing and Future Work

• The high salinity test for this core will be repeated.
• Two more Pc measurements using cores with different lithofacies will be conducted at reservoir P and T.
Acknowledgements

• C&PE faculty members:
  – Norman Morrow
  – Mohammad Piri
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  – Mahdi KazemPour
  – Nina Loahardjo
  – Winoto Winoto
  – Xiao Wang

• EORI
  – Peigui Yin

• Minnelusa Consortium