FULL LENGTH ARTICLE

Salinity of injection water and its impact on oil recovery absolute permeability, residual oil saturation, interfacial tension and capillary pressure

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Abstract Laboratory tests and field applications show that low-salinity water flooding could lead to significant reduction of residual oil saturation. There has been a growing interest with an increasing number of low-salinity water flooding studies. However, there are few quantitative studies on flow and transport behavior of low-salinity IOR processes. This paper presents laboratory investigation of the effect of salinity injection water on oil recovery, pressure drop, permeability, IFT and relative permeability in water flooding process. The experiments were conducted at the 80 °C and a net overburden pressure of 1700 psi using core sample. The results of this study have been shown oil recovery increases as the injected water salinity up to 200,000 ppm and appointment optimum salinity. This increase has been found to be supported by a decrease in the IFT. This effect caused a reduction in capillary pressure increasing the tendency to reduce the residual oil saturation.

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1. Introduction

Water flooding has been widely used as a secondary method to improve oil recovery for most oil reservoirs. Apart from formation damage, water floods are traditionally designed without considering the composition of the injected brine. In the last decades however, the potential of injecting low salinity fluids instead of seawater with high salinity has widely been discussed. However recent laboratory core flood studies and field tests have shown that low-salinity water flooding could result in a substantial oil recovery increase (2–40%) over traditional water flooding in many cases, depending on the reservoir formation minerals and brine composition [1–4].
The possible mechanisms for low-salinity water flooding to improve oil recovery could be attributed to: (1) the wettability change toward water wet as a result of clay migration; (2) the pH increases as a result of CaCO₃ dissolution, which increases oil recovery by several mechanisms including wettability alteration, generation of surfactants, and reduction in IFT; and (3) multiple-component ion exchange between clay mineral surfaces and the injected brine. In general, the oil recovery improvement during low-salinity water flooding is recognized to depend on multiple-component ion, clay content, formation water composition ([Ca²⁺, Mg²⁺]), and oil composition [3,5,6].

Understanding the chemistry of both the injection brine and reservoir brine is the key for optimizing the effect of low salinity water flooding. Previous results from core flooding experiments have indicated that there is a correlation between the shale presence in the reservoir and the injection and reservoir brine [7]. Analysis of the reservoir properties have therefore turned out to be important. By injection of brines with lower salinity than the reservoir brine, the double layer between the clay and oil interface has turned out to expand and thus weaken. If the reservoir brine is being properly analyzed, the injection brine can be mixed to maximize the effect of the ionic exchanges taking place between the two brines and the clay surface.

In the literature, low salinity water flooding as a tertiary recovery mechanism has been given most attention [8,9], however, performed experiments on outcrops and reservoir sandstones to compare secondary and tertiary oil recovery by low salinity water flooding. Both single and two phase experiments were performed, and pressure drop and pH were continuously monitored. The single phase core flooding resulted in an increase in pH from 7.7 to 8.8 during low salinity water flooding, and fines production was observed during some of the flooding experiments. Incremental recovery was thought to be coincident with the decrease in salinity and increase in pH on the Berea outcrops. Similar pH increases were not observed during low salinity water in the reservoir sandstone. Among each rock type and oil combination, secondary mode experiments produced more oil than the tertiary experiments. The incremental recovery from the secondary water flooding varied from 6% to 22% compared to the tertiary recovery.

The potential for low salinity water as an EOR mechanism for the North Sea has also been investigated. Several core flooding experiments have been conducted to evaluate the potential of low salinity water on the Snorre field. Skrettingland et al. reported a maximum of an incremental oil recovery of 2% from that by tertiary low salinity experiments [10].

In this study first the effect of injected water salinity on oil recovery by simulating reservoir conditions with core flooding apparatus will be investigated. The effect of salinity on breakthrough recovery, residual oil saturation of oil will also be investigated. The effect of salinity on interfacial tension, viscosity, density, resistivity and pH will be shown in some charts. To make brine, NaCl added to water and 5 samples with different concentrations have been prepared. Finally an optimum salinity that causes the maximum recovery will be presented.

2. Experimental description

2.1. Chemical materials, rock and fluids

In this study materials contained porous medium, brines and oil which we used them in every experiment.

2.1.1. Porous medium

One piece of Cheshmeh Khosh field sandstone core sample with 12.7 (cm) of length and 4.15 (cm) of diameter were used in all the flooding experiments. The core had a porosity of 14.19% and a permeability was equal to 20.8 (md). The core was fired at 300 °C for 60 h in an oven to stabilize the clay content of the core.

2.1.2. Brines samples

Six samples that contained five samples made with combining fresh water and NaCl and one actual water which provided from sea water. The artificial brine concentrations which are used in flooding experiment are 30,000, 60,000, 100,000, 150,000 and 200,000 ppm and sea water concentration is 180,000 ppm.

2.1.3. Oil sample

The oil used in all the flooding experiments was light crude oil with a density of 0.83 (gr/cc) and a viscosity of 3.3 (cp). It was necessary to filter the oil with 5.0 micron filter paper, then 1.2 micron filter paper and finally with 0.45 micron filter paper.

2.1.4. Fluid system properties

It is necessary that we know what occurred after adding NaCl to the fresh water. Actually we should know all the fluid system properties and all factors which interfere with this parameter. Fluid parameters that associated with the salinity effect are density, viscosity, interfacial tension (IFT), pH and resistivity.

- **Density**: The densities of different waters and oil were measured using density meter. Fig. 1 shows density vs. salinity of brines at 23 °C.
- **Viscosity**: The viscosity of different NaCl concentration brines were measured using viscometer. Fig. 2 shows viscosity vs. salinity of brines at 23 °C.
- **Interfacial Tension (IFT)**: The pendent drop method was used to measure the IFT between oil and different brines at 23 °C and atmospheric pressure. Fig. 3 shows how IFT varies with brine salinity.
- **pH**: pH values of the brines used in this paper were measured with pH meter. Fig. 4 shows pH values vs. salinity of brines at 23 °C.
- **Resistivity**: A reference curve shows resistivity vs. salinity using Core Lab. Model CEF resistivity meter with fisher ABS plastic dip-type cell. Fig. 5 shows this curve.

2.1.5. Water analysis

In general there are mainly two sources of water for water flooding, sea water and aquifer water. In this study the salinity of aquifer water varies from fresh water to salt water with more than 180,000 ppm total dissolved solids. Table 1 shows the analysis of aquifer water of Cheshmeh Khosh field. The salinity of normal sea water is around 180,000 ppm dissolved solids; however it varied from one place to another.

2.2. Apparatuses

A schematic of the experimental apparatus used in this study is shown in Fig. 6. It consisted mainly of two constant rate displacement pumps, two transfer cells, a core holder, an oven, a...
Figure 1  Effect of salinity on density at 23 °C.

Figure 2  Effect of salinity on viscosity at 23 °C.

Figure 3  Effect of salinity on IFT at 23 °C.
differential pressure measurement and a recording system, fraction collector; back pressure multiplier and pressure regulator.

2.2.1. Fluid injection system

During the experiments two high performance liquid chromatography (HPLC) pumps were used to displace fluids in the core sample. The operating fluid of the pumps is double-distilled water and it has been injected into the pipes and fittings with constant flow rate from bottom of the fluid accumulator (brine water, crude oil). Therefore, the accumulator fluid was injected into the core sample with a constant flow rate.

2.2.2. Transfer cells or accumulators

They were used to provide high pressure injection. The distilled water is transported from the pumps to the bottom of the accumulator to move the piston upward and compact the contained fluid.

Table 1  Analysis of Cheshme Khosh brine.

<table>
<thead>
<tr>
<th>Radical</th>
<th>Mg/L</th>
<th>Cations</th>
<th>Anions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sodium and potassium</td>
<td>76,558</td>
<td>332,863</td>
<td></td>
</tr>
<tr>
<td>Calcium</td>
<td>13,520</td>
<td>67,600</td>
<td></td>
</tr>
<tr>
<td>Magnesium</td>
<td>1555</td>
<td>12,798</td>
<td></td>
</tr>
<tr>
<td>Iron</td>
<td>875</td>
<td>3125</td>
<td></td>
</tr>
<tr>
<td>Chloride</td>
<td>107,325</td>
<td>415,000</td>
<td></td>
</tr>
<tr>
<td>Sulfate</td>
<td>204</td>
<td>425</td>
<td></td>
</tr>
<tr>
<td>Bicarbonate</td>
<td>586</td>
<td>961</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>200,623</td>
<td>416,386</td>
<td>416,386</td>
</tr>
</tbody>
</table>

Figure 4  Effect of salinity on pH at 23 °C.

Figure 5  Effect of resistivity on pH at 23 °C.
2.2.3. Core holder
The core holder was a kind of Hassler core holder and has 4.5 cm diameter and 13 cm height.

2.2.4. Heating system and air bath chamber
All the systems were placed in an air bath, which was able to control temperature in the range of ambient and 210°C.

2.2.5. Pressure differential gauge
It was used to measure the pressure drop along the core.

2.2.6. Back pressure regulator (BPR) and effluent collector
A back pressure regulator was used to produce a constant back pressure during core flood experiments. One of the BPRs which were installed at the outlet of the apparatus was operated at 156°C and 105 Pa. The effluent was collected to measure oil recovery using a fractional collector.

2.3. Core preparation

2.3.1. Core cleaning
The core were cleaned by the Soxhlet extraction using toluene and methanol, and then dried at 100°C. After drying, the core dimensions, weight, and permeability were measured then it is saturated.

2.3.2. Porosity measurement
In this work the weight method was employed to determine porosity. In this method the weight of core was measured in dry state initially, then it was saturated with distilled water and the weight was measured again. The difference between two measured weights was equivalent to the weight of water which was saturating the core. Since, the pore volume of the core was calculated using the water density and the known bulk volume. Porosity was determined using Eq. (1):

\[ \phi = \frac{V_{\text{fluid}}}{V_{\text{total}}} \]  

(1)

2.3.3. Permeability measurement
The core permeability was measured with brine solution after porosity measurement. Permeability measurement was based on Darcy’s law, which can be rearranged as follows:

\[ \frac{q \mu A}{L} = k \frac{\Delta P}{L} \]  

(2)

where \( q \) is the flow rate, \( \mu \) represents the viscosity of fluid, \( A \) is the cross-sectional area of the core, \( k \) is the permeability, \( \Delta P \) represents the pressure drop along the core, and \( L \) is the length of the core. Then \( q \mu A / L \) was plotted versus \( \Delta P / L \). A straight line passing through the origin was fitted to the data. The slope of the line represents the permeability of the core.

2.3.4. Brine saturation
Since the tests are carried out under irreducible water saturation, first the core sample must be saturated with water and then with oil. Therefore for saturating the core with reservoir brine, the lower core holder valve was kept open so water can be entered from the bottom and to saturate the core to 100%. Then oil was injected into core holder through its stop valve. At this stage, initial level of saturation water or irreducible water saturation was 26%.
2.3.5. Aging
After establishing $S_W$, by displacement with crude oil, the core were removed from the core holder and aged in crude oil in sealed Pyrex jars. The cells were sealed and held at 80 °C for 20 days.

2.3.6. Restoration of core
After flooding the core with different brines, in the cases where restoration was needed, the core was restored to its initial state by cleaning the core. The restoration was performed after first flooding experiment by formation water. After restoration the core plug to initial state, they were ready for low salinity water flooding experiments. The restoration was done by the same procedure as described before.

2.4. Core flooding experiments
A core holder apparatus was used in the flooding experiments. The core was placed in the core holder with a confining pressure of 1700 psi according to axial stress of the depth that core prepared. Identical flooding conditions i.e. a temperature of 80 °C, gravity stable displacement, and a nominal flooding rate of 5 PV were used in all the floods. Furthermore, a back pressure of 200 psi was applied to avoid the formation of gas by light ends in the crude oil. The pressure drop across the core was carefully monitored in all the experiments. The first flood was a continuous injection of formation water (high salinity brine) to remaining oil saturation, while the second flood was a low salinity water injection. Remaining oil saturation after water flooding was considered to be obtained when water cut values were high and stable over time. The produced oil was collected using a fractional collector and the oil recovery was determined as the percentage of original oil in place (percentage of OOIP). The effluent samples were collected regularly and pH was measured and recorded. All flooding experiments which were done to determine the optimum low salinity were conducted in the same core and at the end of each experiment; the core was washed with toluene (Soxhlet extractor method). At the end for recovery of wettability is used from isopropyl.

3. Results and discussion

In this section, the obtained results are analyzed. The main purpose of study was the examination of the ability of low salinity water in improving oil recovery, absolute permeability, pressure drop, IFT and relative permeability in secondary water flooding. Different concentrations of NaCl brines were used in the five experiments and actual water (sea water) was used in the experiments. A summary of fluid and core properties that were used in all the runs is shown in Table 2. The results of the experiments are presented and discussed in the following section.

3.1. Oil recovery

3.1.1. Displacement runs using NaCl brines
Oil recovery as a function of cumulative water injected for runs No. 1 through 6 where different concentrations of NaCl brine were injected is shown in Fig. 7. The breakthrough recovery and recovery at the end of the six runs are summarized in Table 3. The table shows that, in general, both breakthrough recovery and recovery at the end of the run increase with increasing injected water salinity. All the runs are characterized by little oil production after breakthrough.

Fig. 8 shows the breakthrough recovery increased significantly with increasing injected water salinity up to 200,000 ppm NaCl.

Since the runs were terminated at the same number of pore volumes (PV) injected, the recoveries at the end of the runs are appropriate for comparison purposes. So, the oil recovery at injecting 5 PV was chosen for comparison among the runs. Table 3 illustrates the analysis of oil recovery at injecting 5 PV. It is noticed that when the injected water salinity increased, recovery increased (Fig. 9).

3.1.2. Discussion
The fractional flow equation [11] that describes the linear flow of oil and water in porous medium can be used to explain the results obtained in section above:

$$f_w = \frac{1 + \frac{k_{ro}}{k_w} \times \frac{\mu_o}{\mu_w} \times \frac{\phi}{\phi_o} \times \frac{d\sigma}{d\rho}}{1 + \frac{k_{ro}}{k_w} \times \frac{\mu_o}{\mu_w} \times \frac{\phi}{\phi_o} \times \frac{d\sigma}{d\rho}}$$

where $f_w$: fractional flow of water; $A$: cross sectional area; $\mu_o$: oil viscosity; $\mu_w$: water viscosity; $k_{ro}$: oil relative permeability; $k_{rw}$: water relative permeability; $q$: total flow rate; $dp/dx$: capillary pressure gradient.

Examination of the above equation indicates that oil displacement is affected by: water injection rate, viscosity ratio and implicitly by wettability and IFT. The water injection rate was kept constant through all the runs, so it did not have any effect on oil recovery in this paper.

Wettability is believed to have negligible effects on oil recovery in this study, since only the sandstone core (considered to be a water wet rock) was used. The negligible effects of wettability are supported by the fact that in all the runs, a large fraction of the original oil in place was produced before breakthrough with little oil recovered afterward as shown in Table 3 and Fig. 8. This is a characteristic of water wet rocks. The procedure used to clean the core apparently did not alter the wettability of the rock sample.

Changing the salinity of the injected water has an influence on both IFT and water viscosity as was shown in Figs. 2 and 3 at surface condition. The water viscosity increases with increasing water salinity, while the oil viscosity was kept constant using the same oil in all the runs. As a result, the viscosity ratio ($\mu_w/\mu_o$) decreases with increasing water salinity.

The increase in oil recovery (both breakthrough and at the end of the run) is believed to be caused by the reduction in IFT and the reduction in viscosity ratio. Reducing IFT increases the tendency of water to displace oil by decreasing the capillary forces. Although the change in IFT among the runs was small, it is believed to have an effect on oil recovery. This was observed by Mungan [12], who showed an increase in oil recovery as IFT decreased from 40.0 to 0.5 dyne/cm as shown in Fig. 10.

Viscosity ratio is the order factor that contributed to the increase in oil recovery. The increase of viscosity ratio decreases the mobility of oil relative to the mobility of water, which causes an earlier breakthrough and hence, less oil recovery. In this study, the viscosity ratio varied from 1.83 to 2.87.
The combined effects of IFT (capillary forces) and viscosity ratio (viscous forces) on oil recovery can be demonstrated by capillary number ($N_{ca}$) which was introduced by Meirose and Brandner [13].

$$N_{ca} = \frac{v l_w}{r_{ow}}$$

where $N_{ca}$: capillary number; $v$: interstitial velocity (cm/s); $\mu_w$: water viscosity (pa.s); $\sigma_{ow}$: IFT between oil and water (dyne/cm).

As indicated before, the rate was kept constant, so it did not have any effect on oil recovery. As the capillary number increases, $S_{or}$ decreases. This can be achieved by either lowering IFT or increasing $\mu_w$. Fig. 11 shows $S_{or}$ as a function of the capillary number. It is observed that $S_{or}$ decreases with increasing capillary number. Also, according to Fig. 12, $S_{or}$ decreases with increasing water salinity.

### 3.1.2. Effect of salinity on absolute permeability

Although the core sample was fired at 300 °C for 60 h, to stabilize the clay content, the absolute permeability the core sample was measured using different salinity brines. Fig. 13 shows how the absolute permeability varied with salinity. The permeability increased from 20 md to 21 md at 30,000 to 200,000 ppm NaCl. This small variation is believed to be caused by little swelling of the clay particles in the core. This small variation in permeability does not have any effect on oil recovery.

### 3.1.3. Capillary pressure measurements

Capillary pressure measurements are essential for the analysis of water flooding experiments. A plot of capillary pressure vs. saturation of a rock sample can be used to determine the irreducible water saturation and residual oil saturation of the rock sample.

In this study, the Hassler and Brunner method [14] was used to determine the capillary pressure curves from centrifuge data. The experiments were conducted on the core sample, using oil and different brines. All the experiments were conducted at 80 °C. The core sample was initially saturated with brines. The drainage capillary pressure curves

### Table 2 Summary of fluid and core properties for all the runs.

<table>
<thead>
<tr>
<th>Test</th>
<th>LWS (ppm)</th>
<th>$L$ (cm)</th>
<th>$D$ (cm)</th>
<th>$\Phi$ (%)</th>
<th>$K_{abs}$ (md)</th>
<th>$S_{wi}$ (%)</th>
<th>$\mu_w$ (cp)</th>
<th>Density (gr/cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>200,000</td>
<td>12.7</td>
<td>4.15</td>
<td>14.19</td>
<td>20.8</td>
<td>26.1</td>
<td>1.1517</td>
<td>2.04</td>
</tr>
<tr>
<td>2</td>
<td>150,000</td>
<td>12.7</td>
<td>4.15</td>
<td>14.19</td>
<td>20.8</td>
<td>26.1</td>
<td>1.14</td>
<td>1.649</td>
</tr>
<tr>
<td>3</td>
<td>100,000</td>
<td>12.7</td>
<td>4.15</td>
<td>14.19</td>
<td>20.8</td>
<td>26.1</td>
<td>1.112</td>
<td>1.331</td>
</tr>
<tr>
<td>4</td>
<td>60,000</td>
<td>12.7</td>
<td>4.15</td>
<td>14.19</td>
<td>20.8</td>
<td>26.1</td>
<td>1.086</td>
<td>1.267</td>
</tr>
<tr>
<td>5</td>
<td>30,000</td>
<td>12.7</td>
<td>4.15</td>
<td>14.19</td>
<td>20.8</td>
<td>26.1</td>
<td>1.052</td>
<td>1.152</td>
</tr>
</tbody>
</table>

### Table 3 Breakthrough recovery and final recovery at the end of NaCl brine runs.

<table>
<thead>
<tr>
<th>Num.</th>
<th>Concentration</th>
<th>$\mu_w$</th>
<th>B.T recovery</th>
<th>Final recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>30,000</td>
<td>2.873264</td>
<td>31</td>
<td>35</td>
</tr>
<tr>
<td>2</td>
<td>60,000</td>
<td>2.61247</td>
<td>33</td>
<td>39</td>
</tr>
<tr>
<td>3</td>
<td>100,000</td>
<td>2.486852</td>
<td>34</td>
<td>41</td>
</tr>
<tr>
<td>4</td>
<td>150,000</td>
<td>2.007277</td>
<td>36</td>
<td>42</td>
</tr>
<tr>
<td>5 (sea</td>
<td>180,000</td>
<td>1.622549</td>
<td>37</td>
<td>45</td>
</tr>
<tr>
<td>6</td>
<td>200,000</td>
<td>1.838889</td>
<td>38</td>
<td>48</td>
</tr>
</tbody>
</table>

Figure 7 Oil recovery vs. water injected for NaCl brine runs.
Figure 8  Breakthrough recovery as a function of water salinity.

Figure 9  Oil recovery as injected water salinity for NaCl brine runs.

Figure 10  Effect of IFT on displacement of a nonwetting by a wetting liquid by Mungan.
Figure 11  $S_{or}$ vs. capillary number for all brine runs.

Figure 12  Residual oil saturation vs. salinity.

Figure 13  Effect of salinity on absolute permeamility.
Figure 14  Drainage capillary pressure curve.

Figure 15  Imbibition capillary pressure curve.

Figure 16  Pressure drop vs. cumulative water injection for NaCl brine runs.
were obtained by displacing the brines with oil. At the end of each drainage cycle, the imbition capillary pressure curve was obtained. The effect of water salinity on drainage and imbibitions capillary pressure curves is shown in Figs. 14 and 15.

The following remarks can be observed from the drainage capillary pressure curves. First, the curves slightly toward lower water saturations at the IFT decreased. Second, the residual wetting phase saturation decreased. However, the ambition curves showed a significant shift toward higher water saturation (lower oil saturation) with decreasing IFT and so $S_{or}$ decreased.

The residual oil saturations observed at the end of the imbibition cycles were lower than those obtained in the flooding experiments as shown in Fig. 12. The differences are probably caused by the differences in flow behavior. Whereas the capillary number $\frac{\mu_l \xi}{\sigma}$ controls $S_{or}$ obtained by flooding experiments, the bond number $\frac{\Delta V_{g} \xi}{\sigma}$ significantly affects the fluid distribution in the capillary pressure experiments [15].

3.1.4. Relative permeability

According Fig. 7 a little oil is produced after breakthrough, which means small change in water saturation is obtained after breakthrough. Pressure drop as a function of cumulative water injected for NaCl brine runs is shown in Fig. 16. All the curves exhibited a pressure rise until breakthrough and then pressure drop, before it stabilizes when no more oil is produced.

The relative permeability curves for NaCl brine runs are shown in Figs. 17 and 18. It is noticed that the irreducible water saturation was almost constant for all the runs while $S_{or}$ changed with the injected brine.

For NaCl brine runs, both oil and water relative permeabilities shifted to higher water saturations with increasing water salinity.

The dependence of relative permeabilities on IFT has been shown in the literature to be controversial. Some investigators [15] found that relative permeabilities to oil and water were affected only when the IFT values were lower than 0.1 dyne/cm. However, some investigators found similar results as
found in this study. Leverette [16] showed that reduction of IFT from 35 to 5 dyne/cm increased the permeabilities of both oil and water phases by 20–30%. Mungan [12] found that the relative permeability ratios (wetting/non-wetting) decreased with decreasing IFT from 25 to 5 dyne/cm.

4. Conclusions

The main issues addressed in this paper are improving oil recovery from sandstone reservoir. Based on the results of experiments, the following finding can be concluded:

- Oil recovery increased as the injected water salinity increased up to 48% for 200,000 ppm water salinity.
- The IFT decreased with increasing water salinity.
- For NaCl brine runs, both oil and water relative permeabilities shifted to higher water saturations with increasing water salinity.

References