Investigation of residual oil saturation at different capillary number regions through Surfactant-Polymer flood experiments

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Abstract. The global demand for oil production is increasing, emphasizing the importance of improving the efficiency of Enhanced Oil Recovery (EOR) techniques. However, the existence of in situ factors related to capillarity of porous media and trapping forces hinder the efficacy of EOR processes. Capillary Number (Nca) analysis is a quick method for determining the effectiveness of an EOR project at the early-stage design. Capillary Desaturation Curves (CDC) depict the effect of the capillary number on residual oil saturation (Sor). The capillary number is defined as the ratio of mobilization forces (viscous force) to trapping forces (capillary force). The literature contains numerous correlations for capillary number equations, as well as research that investigate the effect of interfacial tension, wettability, and fluid viscosities on the capillary number-residual oil saturation relationship. While most correlations focused on the reduction of residual oil saturation after waterflood, this study consider the use of EOR techniques, specifically Surfactant-Polymer flood (SP), in a secondary mode, i.e. before waterflood. Such considerations may potentially alter the recommendations for EOR procedures in field. In this study, SP flow experiments were conducted on cores having initial oil saturation conditions to determine the final oil saturations. Eight coreflooding experiments were conducted at various capillary number conditions and flow orientations to assess the effect of capillary and viscous forces on the performance of SP flooding during two stages: before and after breakthrough. The magnitudes of the capillary and viscous forces were used to precisely adjust the capillary number conditions. The results indicate that, at low capillary number conditions, vertical injection yielded more stable displacement than horizontal injection. At intermediate capillary number conditions, horizontal and vertical injection experiments showed comparable oil recovery. However, at higher capillary number conditions, the displacement is unstable and residual oil saturation does not consistently decreases as the capillary number increases.

1 Introduction

The capillary number describes the balance of viscous and capillary forces in the flow of immiscible fluids through porous media (Fulcher et. al., 1985; Garnes & Mathisen, 1990). Mathematically, it is expressed as:

$$N_c = \frac{\text{viscous force}}{\text{capillary force}} = \frac{F_v}{F_c}$$

Low capillary numbers indicate situations in which capillary forces predominate over viscous forces (known as capillary dominant conditions), whereas high capillary numbers indicate situations in which viscous forces surpass capillary forces (known as viscous dominant conditions). Several scholars have suggested different mathematical expressions for the capillary number. Moore & Slobod (1955) defined the capillary number based on the wettability of the porous media. They define the capillary number for a water wet system as:

$$\mathrm{Nc} = \frac{\nu\mu}{\sigma\cos\theta}$$

And for an oil-wet system as:

$$\mathrm{Nc} = \frac{\nu\mu L}{\sigma\cos\theta}$$

Where:
- v = Superficial velocity
- σ = Interfacial tension between oil and water
- L = Length of oil droplet
- μ = The viscosity of the displacing phase

Abrams (1975) proposed a capillary number equation that took into account the viscosity ratio of the displacing fluid and the displaced fluid. This equation is given by:

$$\mathrm{Nc} = \frac{\nu\mu}{\sigma\cos\theta}\left(\frac{\mu w}{\mu o}\right)^{0.4}$$

Numerous studies have been conducted to emphasize the impact of capillary and viscous forces on the efficiency of immiscible displacement processes. This correlation is often known as Capillary Desaturation Curves (CDC). Figure 1 depicts a typical trend in this relationship, with low capillary number values corresponding to high and steady residual oil saturation, showing that capillary forces are dominant. At

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intermediate capillary number values, a transition zone appears, indicating a competition between capillary and viscous forces. In this case, capillary force acts as a trapping force, whereas viscous force acts as a mobilization force. Finally, for high capillary values, viscous force prevails and residual oil saturation decreases.

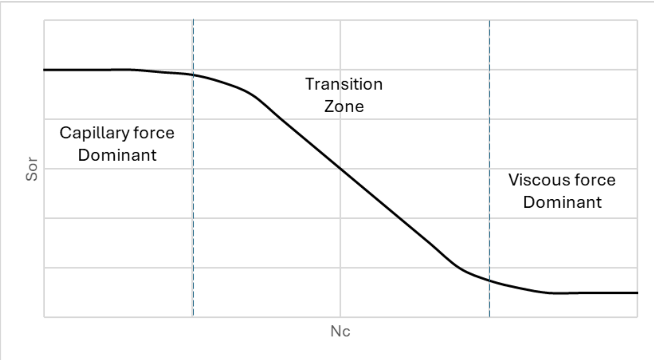


Fig.1. A typical Classic Capillary Desaturation Curve.

Some researchers presented this relation as shown in Figure 2 and Figure 3 (Abrams, 1975), Figure 4 (Fulcher et al., 1985) with a slight modification in the definitions of x and y-axis.

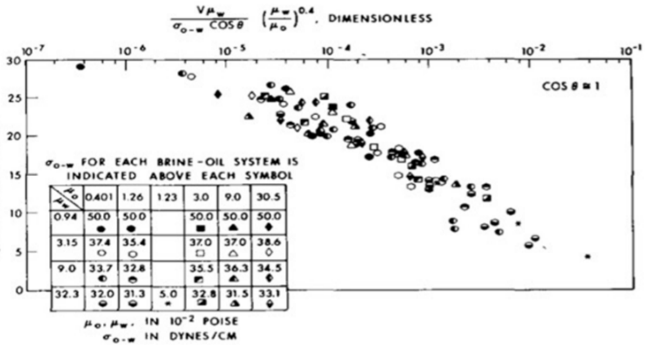


Fig. 2. Effect of capillary number on S_{or} (Abrams, 1975).

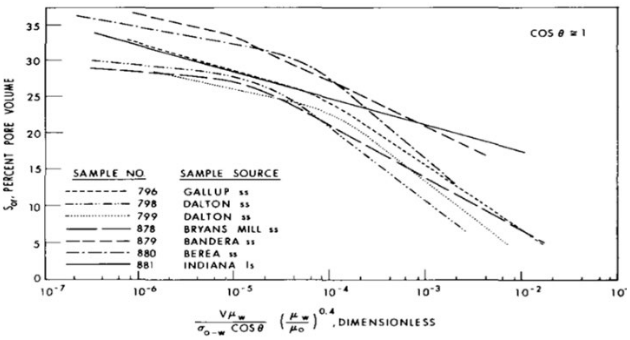


Fig.3. Effect of capillary number on S_{or} for various rock samples (Abrams, 1975).

In the capillary dominant region, residual oil saturation remains is consistently higher than in the viscous dominant region. Beyond a critical capillary number value, often beyond NC > 10^{-6}, residual oil saturation tends to decrease. Majority of water flooding projects are conducted in the low capillary number region (less than 10^{-6}), where the residual oil saturation is rather constant.

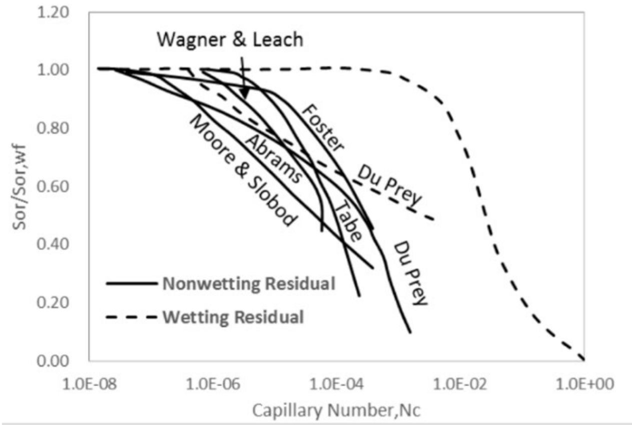


Fig. 4. Summary of typical CDC (Fulcher et al., 1985).

CDC is an invaluable tools for designing Enhanced Oil Recovery (EOR) processes. The alterations in capillary number introduced through EOR processes can be utilized to predict the expected changes in the residual oil saturation, showing the EOR process's efficiency. By examining the definition of capillary number, the residual oil saturation can be reduced by increasing the displacing fluid flow rate (increase viscous force), increasing the displacing fluid viscosity (increase viscous force), and/or lowering the interfacial tension (decrease capillary force). In many cases, the options to increase the displacing fluid velocity are restricted by numerous operational challenges. For example, reservoir fracture pressure prevents an increase in the injection rate of a displacing fluid.

The displacing fluid viscosity can be increased by introducing polymer molecules to the injected fluid, while the interfacial tension can be lowered by adding surfactants. In many situations, the advantages of polymer and surfactant flooding are combined using Surfactant Polymer (SP) flooding. In these applications, the objective is to increase the viscosity of the displacing fluid viscosity as well as decreasing the interfacial tension between the displacing and displaced fluids. This enhanced sweep efficiency and decreases the capillary forces.

Recent studies have demonstrated a more complex link between capillary number and residual oil saturation especially in the viscous dominant zone (high capillary number). For example, Qi et al. (2009) showed a different trend of residual oil saturation versus capillary number in the high capillary number region as illustrated in Figure 5. Contrary to expectations, residual oil saturation does not decrease consistently as the capillary number increases. The figure shows that at a specific capillary number value, the residual oil saturation might increase or decrease, and the final residual oil saturation does not approach zero. It worth noting that at high capillary number conditions, it is unlikely to establish a stable displacement and as a result, sweep efficiency significantly reduced, resulting in an overall drop in oil recovery factor.

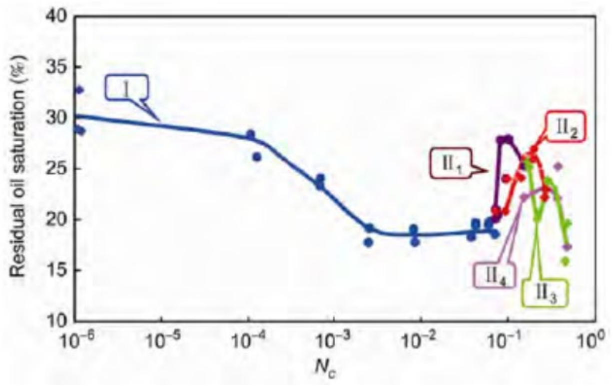


Fig. 5. Residual Oil saturation versus Capillary number (Qie et al., 2009).

Wang et al. (2010) found that conditions with low interfacial tension and the highest capillary number did not consistently yield favorable oil recovery results, emphasizing the importance of prioritizing mobility control over reducing the capillary number approach. The study involves core flooding experiments conducted on two consolidated sandstone cores with permeabilities of 2 µm2 and 1.0 µm2, showcasing a heterogeneous formation. Figure 6 shows the recovery versus capillary number for six Surfactant Polymer (SP) formulation viscosities, indicating that when the capillary number increases, oil recovery does not always follow suit. Consequently, they concluded that optimizing interfacial tension and viscosity to regulate mobility (thus enhancing sweep efficiency) proves more advantageous than achieving an ultra-low interfacial tension and the highest possible displacing fluid viscosity.

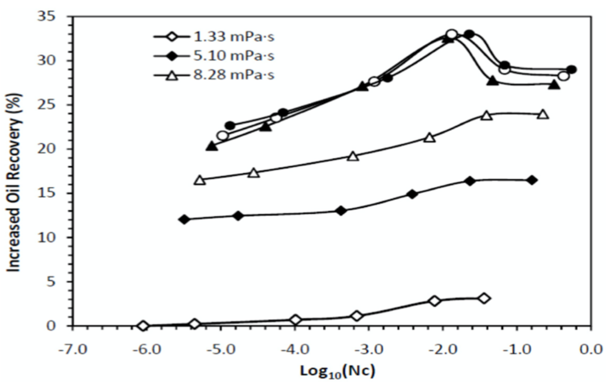


Fig. 6. SP recovery with different capillary numbers (Wang et al., 2010).

Guo et al. (2022) studied the effect of ultra-low interfacial tension on oil recovery factor in surfactant polymer flooding experiments. They conducted sandpack flooding experiments with a consistent injection rate and varying interfacial tension (IFT) values. Four experiments were conducted: one featured polymer flooding, while the other three used surfactant polymer flooding. Figure 7 illustrates the oil recovery for these experiments plotted against injected pore volume. They concluded that reducing the interfacial tension in surfactant polymer flooding proves advantageous up to a certain threshold, after which an ultra-low interfacial tension becomes unfavorable due to suboptimal sweep efficiency.

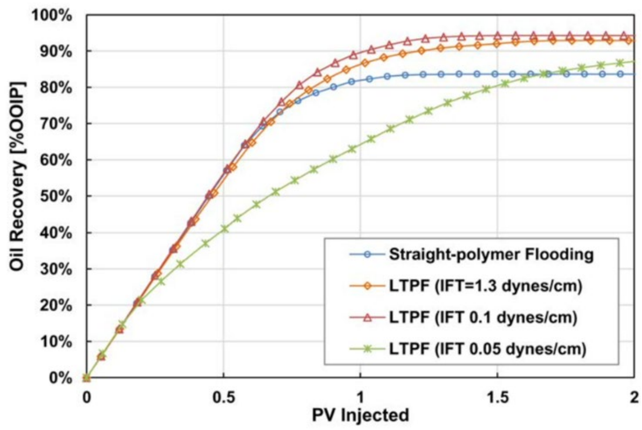


Fig. 7. Oil recovery versus pore volume injected for experiments 1-4 (Guo et al., 2022).

The previously cited literature emphasizes the importance of ensuring a balance between sweep efficiency, provided by increased viscous force, and the necessity to overcome the trapping forces, provided by decreasing the capillary force.

Most research studies on the relationship between capillary number and residual oil saturation were conducted in a tertiary mode with the SP flood begin after waterflooding. In these cases, the trapped oil following waterflood is released by introducing surfactant to reduce capillary force and polymer to provide the necessary sweep. However, this study investigates the effect of viscous and capillary forces by performing SP flood in a secondary mode. The objective of this approach is to assess the contribution of viscous and capillary forces in oil recovery prior and following breakthrough. Coreflooding experiments were conducted to highlight the differences in these contributions under different capillary number conditions. Two SP flood experiments were conducted at specified capillary number values, depicting the capillary dominant region, the transition region, and viscous dominant region, using different flow directions: horizontal and vertical injection. The decision to perform the SP at multiple flow directions was made to highlight the role of gravity on maintaining the stability of the front, as vertical injection flow direction is typically advocated to ensure stable flood fronts (Butler and Jiang, 1996, Lee, 2012). The next section describes the experimental approach and the materials used in this study.

2 Methodology and Material Used

2.1 Core Samples

In this study, eight core flooding experiments were conducted to simulate different conditions of capillary numbers and flow directions. In all experiments, synthetic Berea sandstone cores, measuring 3.78 cm in diameter and 30.2 cm in length, were utilized. Before each experiment, the core was kept in air dried oven at a temperature of 110 °C for 24 hours. The core was subjected to vacuuming for another 24 hours to ensure that no gas (air) was left inside. Then, water was allowed to flow into the core by opening the valve connected to a water accumulator and the core porosity was measured. After the water saturation step, the permeability of the core was measured by varying water injection rate and observing the pressure drop along the core sample. Table 1 summarizes the properties of the core samples used in this study.

Table 1: Summary of core properties.

Exp.	Porosity (ϕ) %	Permeability (k) md
1	17.0	32.8
2	17.9	32.2
3	18.2	21.1
4	17.4	43.0
5	17.9	38.5
6	17.3	38.5
7	18.5	39.5
8	17.9	32.7

2.2 Water

Two NaCl solutions were prepared representing low and high salinity formation water. The salinity of the first solution was 5000 ppm achieved by adding 5 grams of NaCl salt to 1000 ml of distilled water. Similarly, the salinity of the second solution was 200,000 ppm achieved by adding 200 grams of NaCl to 1000 ml of distilled water. Furthermore, the solutions were mixed via a magnetic stirrer for approximately 24 hours. Any dissolved gas, especially oxygen, was removed by Nitrogen purging.

2.3 Oil

Dead oil samples from an actual reservoir were used in this study. The density of the used oils ranges from 0.854 to 0.864 with a viscosity of 11 to 17.5 cp.

2.4 Polymer Description

Flopaam 5115 is used as a viscosifying polymer that is manufactured by SNF, it is an Acrylamide/ATBS/Acrylic acid polymer with medium anionicity and a medium molecular weight.

2.5 Surfactants Description

Two Surfactants were used in this study. The first surfactant is Triton X-100 manufactured by Dow Chemical Company. It is a nonionic detergent with a specific gravity of 1.065 at 25°C, molecular weight is 625, viscosity (Brookfield) of 240 cps at 25°C, pH (5% aqueous solution) ranges from 6.0 to 8.0, and a critical micelle concentration (CMC) range of 0.22 to 0.24 mM. The second surfactant is ENORDET J071 manufactured by Shell Chemicals. It is an alcohol alkoxy sulphate (AAS) with a molecular weight of 618, pH is 10.5, and a very high applicable salinity.

Table 2 summarizes the concentration of each chemical constituent used in the coreflooding experiments.

Table 2: Summary of chemical formulation used in each experiment.

Exp.	Water Salinity (S) ppm	Polymer Concentration (C_P) ppm	Surfactant Concentration (C_S) % wt.
1	5,000	0	0
2	5,000	0	0
3	5,000	2,000	0.5*
4	5,000	2,000	0.5*
5	200,000	2,000	2**
6	200,000	2,000	2**
7	200,000	3,000	2**
8	200,000	3,000	2**

*Triton X-100 surfactant
**ENORDET-J071

2.6 Flow experiment procedure

After determining the porosity and absolute permeability of each core, the core was oil flooded to establish the initial oil saturation conditions. Then the core was flooded with the designated chemical formulation at a predetermined injection rate to establish the required capillary number conditions. Table 3 summarizes the experimental conditions. All experiments were conducted at ambient temperature.

Table 3: Summary of experimental conditions.

Exp.	Flow Direc-tion	S_{oi}	μ_o cp	γ Sec^{-1}	μ_w cp	σ mN/m	q cc/min	v cm/min	**Nc***
1	H	0.72	17.5	237	1	23.19	0.84	0.440	1.0E-06
2	V	0.755	11	189	1	22.9	0.68	0.338	9.4E-07
3	H	0.75	11	225	15	0.93	0.66	0.323	6.6E-05
4	V	0.84	11	161	17	0.93	0.66	0.337	7.2E-05
5	H	0.70	11	155	7	0.08	0.61	0.303	5.3E-04
6	V	0.54	11	158	7	0.08	0.61	0.313	5.5E-04
7	H	0.62	11	136	13	0.08	0.55	0.265	5.9E-04
8	V	0.70	11	152	13	0.08	0.55	0.274	6.1E-04

***Calculated**

The capillary numbers in Table 3 were calculated according to the following definition:

$$N_c = 1.67 \times 10^{-4} \frac{\mu_w v}{\sigma} \left(\frac{\mu_w}{\mu_o}\right)^{0.4} \quad (1)$$

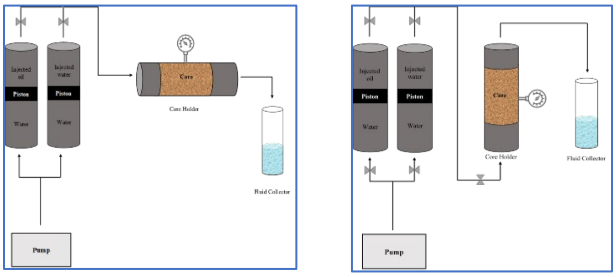
In equation 1, μ_w represents water viscosity (cP), μ_o represents oil viscosity (cP), σ represents interfacial tension between solution and oil (mN/m), and v represents the interstitial velocity (cm/min) which is calculated as

$$v = \frac{q}{\emptyset A} \quad \text{Eq. 2}$$

Where:

q = Injection rate, cc/min
ϕ = porosity, fraction
A = Cross sectional area of the core sample, cm^2

Experiments 1 and 2 served as base cases for low capillary number cases, usually waterflooding, under horizontal and vertical displacement conditions, respectively. Experiments 3 to 8 involved different injection directions to achieve the design capillary number conditions using polymer and surfactant. Figure 8 shows schematic presentations of the core flooding setups for the vertical and horizontal injection experiments.



(A) Horizontal Setup (B) Vertical Setup

Fig. 8. Schematic diagram of the core flooding setups.

3 Results and discussion

The experimental results are shown below, first for each capillary number region, followed by a comparison of oil recovery factor versus capillary number for both horizontal and vertical displacement experiments. Finally, the relationship between residual oil saturation and capillary number (CDC curve) is discussed.

3.1 Low Capillary Number Case (N_c ~ 1E^{-06}).

Under conditions of low capillary number, the viscous force is relatively weak in comparison to the capillary force, resulting in lower mobilization forces compared to trapping forces. Two core flooding experiments were conducted in the low capillary number region (experiments 1 and 2). In experiment 1, the flow direction was set horizontally, whereas in experiment 2, the flow direction was vertical. Table 3 summarizes the conditions for Experiments 1 and 2 which are simple waterflooding studies that serve as the baseline for comparison with the subsequent experiments. Figure 9 shows the oil recovery factor plotted against the pore volume of injected water for Experiment 1 (Horizontal Flow Case) and Experiment 2 (Vertical Flow Case). In these experiments, the oil-water ratios were unfavorable ($M_v > 1$).

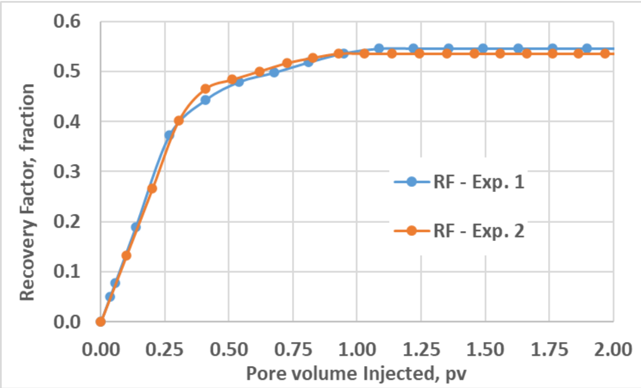


Fig. 9 Oil recovery factor versus pore volume injected for Experiments 1 and 2.

Figure 9 indicates that water breakthrough occurred in the horizontal and vertical flow cases at the same pore volume injected (BT = 0.41). The oil recovery factor at breakthrough for the horizontal flow case is 44%, compared to 46.5% in the vertical case. The ultimate oil recovery factor for both horizontal and vertical cases was approximately 54%. Furthermore, the residual oil saturations in experiments 1 and 2 were 0.326 and 0.351, respectively, which is in good agreement with most flooding experiments performed under low capillary number conditions. Figure 9 suggests that the flow direction has a little impact on the performance of the immiscible displacement. Consequently, one might conclude that in the presence of strong capillary and weak viscous forces, the gravity force has insignificant effect.

3.2 Intermediate Capillary Number Case (N_c ~ 6.9E^{-05}).

In Experiments 3 and 4, the capillary number was reduced to around 7×10^{-5} by increasing the viscous force and decreasing the capillary force. This was achieved by adding 2,000 ppm of polymer to the injected solution to increase the viscosity of the injected water to 15 cp. Additionally, 0.5% wt. of surfactant was added into the injected solution to reduce the interfacial tension between water and oil to 0.93 dynes/cm. Figure 10 shows the relationship between oil recovery factor and the pore volume of injected water for Experiments 3 and 4. Experiment 3 involved horizontal flow, while Experiment 4 involved vertical flow.

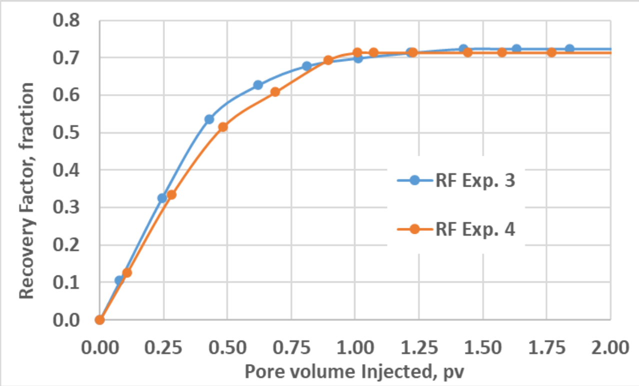


Fig. 10. Oil Recovery Factor versus Pore Volume Injected for Experiments 3 and 4.

Figure 10 illustrates that the injected chemical slugs perform similarly in both injection directions, demonstrating that flow direction has no major impact at capillary number values of 1×10^{-3}. Water breakthrough occurred earlier in the horizontal flow case (BT = 0.43) compared to the vertical flow case (BT = 0.48) where the horizontal flow case has a higher oil recovery factor (54%) than the vertical flow case (52%). The ultimate oil recovery factor in both horizontal and vertical cases was around 72%. Furthermore, experiments 3 and 4 had residual oil saturations of 0.206 and 0.241, respectively. When experiments 3 and 4 compared to their counterparts, experiments 1 and 2, they show a 12% reduction in residual oil saturation and an increase of approximately 17% in oil recovery factor.

3.3 Intermediate Capillary Number Case (Nc ~ $5.4E^{-04}$) under high salinity conditions (S = 200,000 ppm).

Experiments 5 and 6 were performed under high salinity conditions. The salinity of the water used in these experiments was 200,000 ppm. To achieve intermediate capillary number conditions of roughly 5.4×10^{-4}, 2% wt. of a modified surfactant, commonly used in high salinity conditions, was combined with 2000 ppm of the polymer. The interfacial tension of the solution was 0.08 mN/m, and the viscosity of polymer solution was reduced to 7 cP due to the high salinity.

It is worth noting that throughout these experiments, we observed the forming of an emulsion in the produced effluent, suggesting the presence of unstable displacement in the cores. The formation of unstable displacement using ultra-low surface tension was noted by many researchers [6, 9, 10].

To separate oil from water, we used a demulsifier to separate oil from water. The used demulsifier is more soluble in oil than in water. AGS analysis was performed to confirm that the demulsifier is soluble in oil more than water. Figure 11 shows a comparison of oil composition before and after adding the demulsifier, confirming that the added demulsifier is more soluble in oil than in water as evidenced by the changes in the peaks of the intermediate components before and after adding the demulsifier.

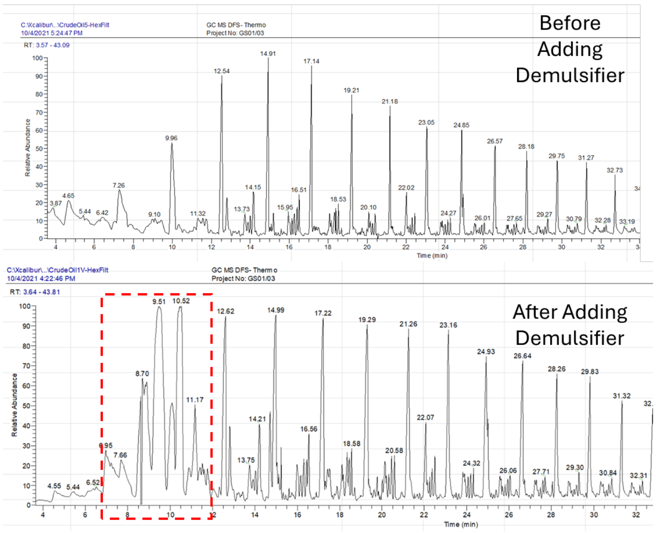


Fig. 11. Change in oil composition after adding demulsifier.

Figure 12 shows the oil recovery factor versus the pore volume of injected water for Experiments 5 and 6. Experiment 5 involved horizontal flow, while Experiment 6 involved vertical flow.

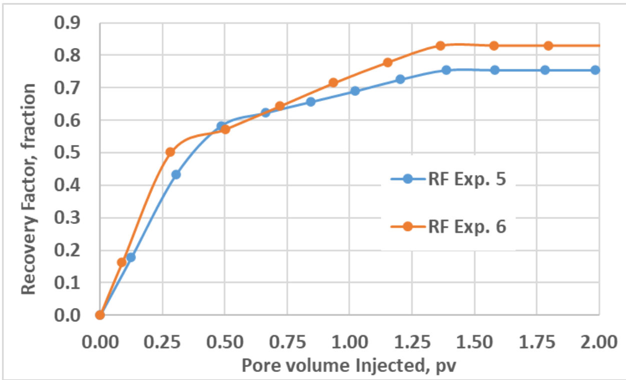


Fig. 12. Oil Recovery Factor versus Pore Volume Injected for Experiments 5 and 6.

Under unstable displacement, unexpected results were found challenging the interpretation of the outcomes. For example, the water breakthrough occurred earlier in the vertical flow case (BT = 0.28) than the horizontal flow case (BT = 0.48). Moreover, the vertical flow case has a 50% oil recovery factor at breakthrough while the horizontal flow case has 58% recovery factor at breakthrough.

At the end of these experiments, the vertical flow case has an ultimate oil recovery factor of 83%, compared to 75% for the horizontal case. Furthermore, experiments 5 and 6 had residual oil saturations of 0.172 and 0.092, respectively. To further validate the superiority of vertical injection over horizontal injection in these experiments, we performed a visual inspection to compare the cores used after these experiments. Figure 13 shows images of the inlet side of the core used in experiments 5 and 6.

Experiment 5 (horizontal Flow) Experiment 6 (Vertical Flow)

Fig. 13. Inlet side of the cores used in Experiments 5 and 6.

Figure 13 clearly indicates that the inlet face of experiment 6 is lighter than the inlet face of experiment 5, suggesting the presence of less hydrocarbon in experiment 6 after the flood. At this time, it is unclear why experiment 6 outperforms experiment 5, but we suspect it is related to the unstable displacement, the complexity of the injected chemical slugs, and/or the difficulties in interpreting the effluent with emulsions.

3.4 Intermediate Capillary Number Case (Nc ~ 6.0E^{-04}) under high salinity conditions (S = 200,000 ppm).

Similar set of experiments, as in the previous case, were performed under capillary number value of 6.0×10^{-4}; experiment 7 for horizontal flow direction and experiment 8 for vertical flow direction. In these experiments, the viscosity was increased to 13 cP by adding 3,000 ppm of polymer to the injected solutions. Figure 14 shows the oil recovery factor versus pore volume of water injected.

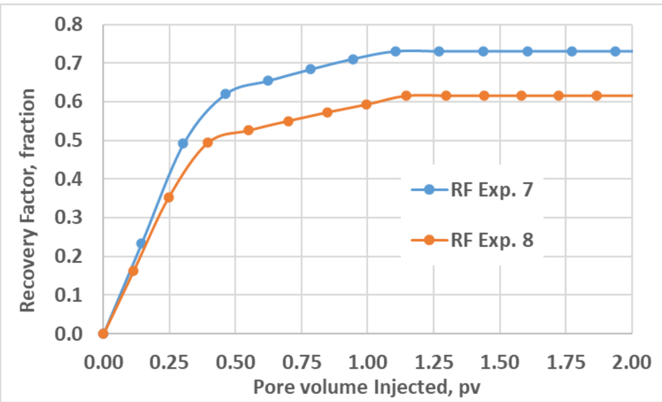


Fig. 14. Oil Recovery Factor versus Pore Volume Injected for Experiments 7 and 8.

It was expected that experiments 7 and 8 would perform similarly, if not better than experiments 5 and 6. However, it appears that the establishment of an ultra-low interfacial tension complicates the standard interpretation of coreflooding studies necessitates a new approach because the displacement process is not stable, as many researchers have noted [6, 9, 10]. Water breakthrough occurred at around 0.46 and 0.40 pv in experiments 7 and 8, respectively. Similar to the previous case, experiments 5 and 6, the water breakthrough earlier in the horizontal flow experiment. However, the difference in the breakthrough times was decreased indicating that the higher solution viscosity played a role. Moreover, the ultimate oil recovery factor was 73% in the horizontal flow direction and 61.5% in the vertical flow direction versus 75.5% and 83.1% in the previous case.

4 Conclusions

Eight coreflooding experiments were conducted at different capillary number conditions and flow orientations to assess the effect of capillary and viscous forces on the performance of SP flooding during two stages: before and after breakthrough. Capillary number was modified by alternating the interfacial tension and mobility ratio with additives to come up with different experimental conditions representing a new capillary number value. Four experiments were performed in the horizontal direction, and four were in the vertical direction. The effect of changing the capillary number was studied and a comparison between vertical and horizontal displacement was performed.

The results show that at low capillary number conditions, flow direction has a negligible effect since capillary forces are dominating. The results indicate that increasing the capillary number can improve the ultimate oil recovery factor for both directions of displacement. Nonetheless, there appears to be a limit where additional increases in ultimate oil recovery are reduced under high capillary number conditions when the displacement becomes unstable. Finally, the results complement earlier researchers' findings indicating that ultra-low tension flooding does not necessarily improve oil recovery.

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