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DESIGN OF LOW SALINITY WATERFLOODING FOR OIL-WET AND WATER-WET CARBONATE RESERVOIRS

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ABSTRACT

Even though low salinity water LSW flooding is proven to be a technically viable process, its economics is still debatable in the oil industry. To improve the process economics, slug injection is proposed technique replacing continues low salinity injection scheme. Literature search has indicated that no work has been reported on the effect of lithology and reservoir wettability & permeability on the optimum low salinity slug size. In this project, the effect of the reservoir wettability (oil wet and water wet systems), lithology (limestone and dolomite), and permeability (low and high) on the design of low salinity slug injection has been experimentally investigated. Interfacial tension, contact angle, and phase behavior studies were conducted. The results indicated that reservoir wettability and lithology have a significant impact on the optimum LSW slug size. Oil-wet and limestone system exhibited a favorable condition for LSW slug injection, which requires a slug of 10% pore volume and produced 90% of the oil in place. For oil wet systems, the lithology had no noticeable impact on the optimum slug size. A high permeability dolomite oil wet system required smaller slug size as compared to a lower permeability system, while the low permeability system exhibited higher oil.

KEYWORDS: *Low salinity, Limestone, Dolomite, Slug, Permeability, Wettability, Lithology*.

INTRODUCTION

Designer water, also known as advanced ion management or smart waterflooding, is a technique in which engineers manipulate the ionic composition of the displacing phase. The flooding fluid destabilizes the initial equilibrium of the crude/brine/grain system, which results in wettability alteration (Sheng, 2013). This field of study is attractive compared to EOR processes because it is economically feasible (does not require expensive chemicals), allows use both at secondary mode (early stage of oil recovery) or tertiary mode (late life cycle of the reservoir), and is environmentally friendly with no associated injection issues (Kazankapov, 2014). However, the principal mechanism of this technique demands much more research to detail it comprehensively. Researchers agree that designer water improves displacement efficiency, i.e., increases the capillary number; however, there is still debate on the mechanism, especially in carbonate reservoirs. The capillary number is the dimensionless ratio of viscous forces to interfacial forces (Tiab & Donaldson, 2015). This parameter is optimized by either increasing the flow rate or lowering the interfacial tension. Limitations in predicting turbulent flow behavior make enhancing interfacial tension the more feasible option since it is a parameter that could be precisely controlled for a given system. The designed technique for this low salinity water operates as follows: in secondary mode, a slug of low salinity is introduced at initial formation water saturation followed by the continuous flood by high salinity formation brine until 100% water cut is realized. This presents the following curiosity: what percentage of effective pore volume (PV) should the low salinity slug be to yield maximum recovery, and does wettability, lithology, and permeability affect this optimum size? Fani et al. (2018) evaluated the efficiency of smart water injection in an oil-wet environment by deploying tertiary smart water "shock slug" injection. They employed 10 times diluted formation brine in various slug volumes, including 0.75, 1, 1.5, and 2 PV, and modeled the low-salinity water (LSW) slug injection followed by continuous high-salinity chase drive. They concluded that employing a small slug size can be as effective as continuous flooding. Chequer et al. (2019) modeled the low-salinity water (LSW) slug injection followed by continuous high-salinity chase drive for an oil-wet system. They found that the volume of optimal low-salinity slug has an order of magnitude of the pore volume of the high-permeability layer. Moradpour et al. (2020) investigated the possibility of co-optimizing the length of the injected slug and soaking time in the low salinity flooding process employing mixed wettability/oil-wet system. They concluded that there is an optimum slug size beyond which increasing the slug size does not exhibit additional oil recovery. All the previous work on the optimum slug determination during low salinity water flooding has employed large slug volumes, approaching the volumes employed in traditional continuous flooding. In addition to that, none of the reported work covered the effect of the reservoir wettability on the optimization of the slug injection. The main objective of this work is to design a low salinity flooding process that results in minimizing the amount of low salinity water while considering the reservoir wettability. This finding is critical as in many oil reservoirs, wettability varies from one area to another, and it should be taken into consideration in designing a low salinity water flooding process for the candidate enhanced oil recovery reservoir.

2. METHODOLOGY AND MATERIALS

To achieve the project objectives, two research stages were designed. Figures 1 display the details of stage 1. Stage 1 consists of core and fluid preparation, petrophysical, fluid, and IFT property measurements. Low salinity water was prepared by diluting seawater obtained from the Gulf area (≈5000 ppm) ten times to yield a salinity of 5000 ppm.

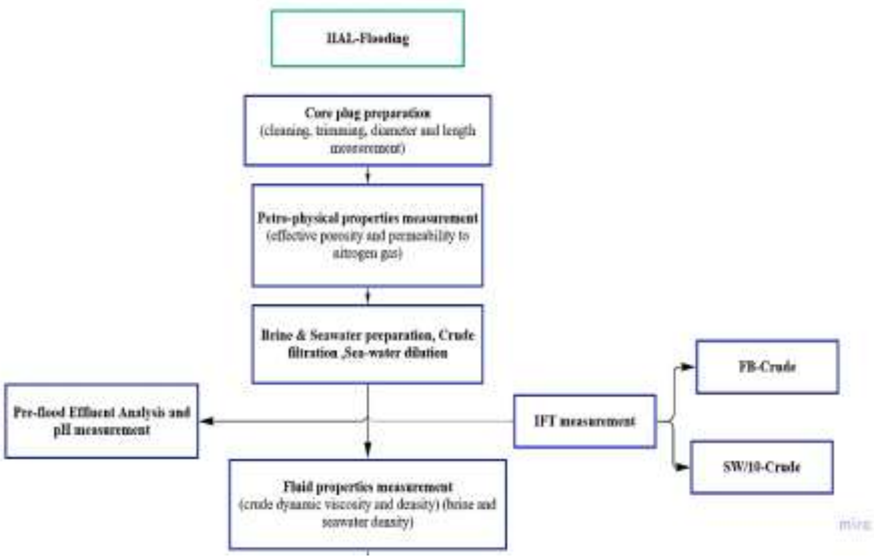


Figure 1: Stage 1 of research methodology.

Stage 2 of research as presented in Figure 2 displays a flowchart of the workflow of the flooding experiments. The procedure includes aging, primary and secondary flooding as well as post flooding measurements.

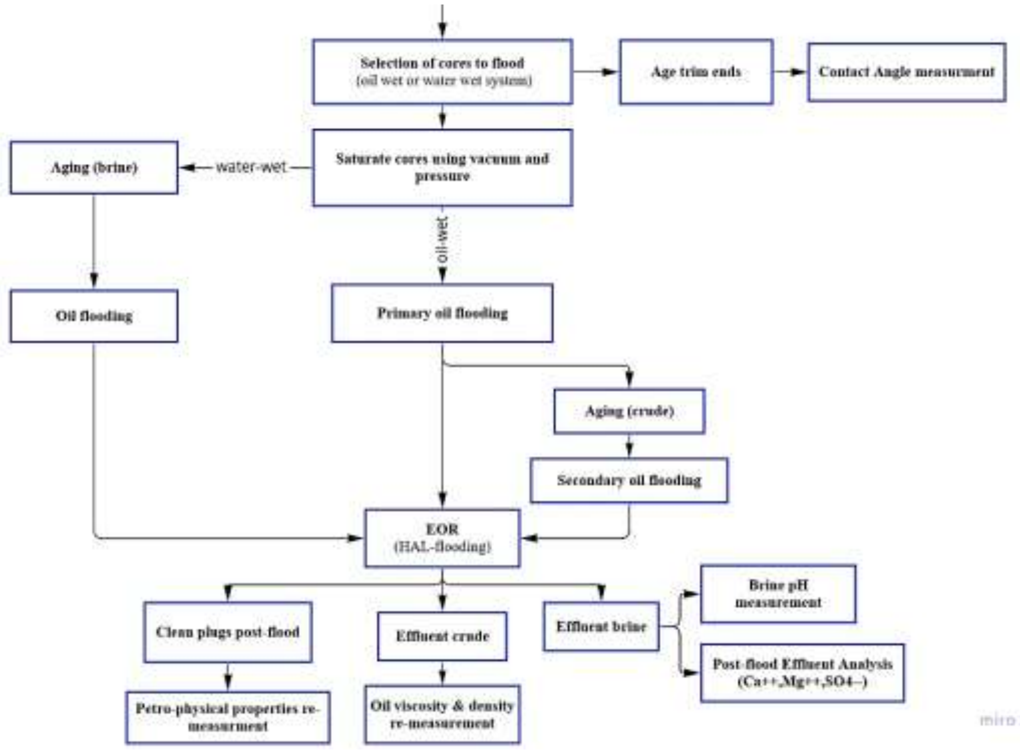


Figure 2: Stage 2 of research methodology.

Interfacial tension measurements of oil/formation brine and oil/low-salinity seawater were carried out using the KRUSS Spinning Drop Tensiometer at ambient temperature and pressure conditions. This test was conducted to assess the role of interfacial tension in displacing the crude oil during the low salinity injection process. Contact angle, a method used to quantify the wettability of grain surfaces, was measured at ambient conditions for both limestone and dolomite rock trim ends. Trim-end cores were aged in oil for four weeks at ambient conditions to resemble the oil-wet conditions of a carbonate reservoir. The trim-ends were placed in low salinity water for four weeks to establish a water-wet system, and the contact angles were automatically measured using Teclis Tracker for 72 hours (see Figure 3). Interfacial tensions (IFT) between oil and the various used waters were measured by pendant drop technique using a Teclis Tracker as well.

Figure 3: L Teclis Tracker used for IFT and contact angle measurements.

2.1. Fluids

Two crude light UAE oils were taken from AS and BH onshore oil fields, having API gravity of 40 and 39 degrees respectively. Both AS and BH crude have a similar dynamic viscosity of 2.93cp and 3.08cp respectively. The viscosity was measured using a rolling ball viscometer at an ambient temperature of 20°C. Both crudes were filtered through an 8.0-micrometer filter paper multiple times prior to any laboratory application. Investigation revealed no asphaltene precipitation in both crudes. The two oils are classified as sweet and have no H2S gas. The following four brines were employed in this project: ASB brine with a total dissolved salt (TDS) of 157,189 ppm, URD with 171,647 ppm, seawater with 54,580 ppm, and low salinity water with 5,101 ppm. The low salinity water was prepared by diluting the seawater by a factor of 10. Table 1 presents the composition of both seawater and the two formation brines.

Table 1: Composition and concentration of the brines.

Ion	Ca	Mg	Na	HCO3	CL	SO4	Salinity, ppm
ASB	13840	1604	44261	33	96566	885	157189
URD	12200	2692	50089	212	106088	366	171647
Seawater	690	2132	16767	123	30924	3944	54580
LSW	69	213	1676	12	2737	394	5101

2.2. Core samples

We categorized sixteen core samples based on their lithology and sub-categorized them into groups with similar permeability. To make twelve of the samples oil-wet, we subjected them to primary oil flooding and aged them in AS crude. For the remaining four samples, we made them water-wet by aging them in formation brine. We confirmed the wettability using contact angle measurements after aging, and the results were consistent with our previous experiments (Zekri et al., 2020). Table 2 shows the core sample classification for limestone cores, while Table 3 presents the classification for dolomite cores.

Table 2: Core samples classification for limestone group ZE-1.

Sample number	Group ID	Introduced Wettability	Permeability classification	Permeability (md)	Mineralogy
2	ZE-1	oil-wet	High	13.798	Limestone
5	ZE-1	oil-wet	High	14.118	Limestone
6	ZE-1	water-wet	High	9.364	Limestone
7	ZE-1	water-wet	High	10.544	Limestone
8	ZE-1	water-wet	High	8.867	Limestone
9	ZE-1	water-wet	High	10.655	Limestone
10	ZE-1	oil-wet	High	14.444	Limestone

18	ZE-1	oil-wet	High	14.462	Limestone

Table 3: Core samples classification for dolomite group ZE-2.

Sample number	Group ID	Introduced Wettability	Permeability classification	Permeability (md)	Mineralogy
1	ZE-2	oil-wet	High	11.777	Dolomite
3	ZE-2	oil-wet	Low	2.724	Dolomite
6	ZE-2	oil-wet	High	9.325	Dolomite
8	ZE-2	oil-wet	Low	1.361	Dolomite
12	ZE-2	oil-wet	Low	3.142	Dolomite
16	ZE-2	oil-wet	Low	1.144	Dolomite
17	ZE-2	oil-wet	High	16.227	Dolomite
18	ZE-2	Oil-wet	High	7.301	Dolomite
21	ZE-2	Oil-wet	High	10.09	Dolomite
22	ZE-2	Oil-wet	Low	1.01	Dolomite

3. RESULTS AND DISCUSSION

3.1. Interfacial tension IFT measurements

We conducted measurements of interfacial tension between oil/formation brine and oil/low-salinity seawater using the KRUSS Spinning Drop Tensiometer at ambient temperature and pressure conditions (see Figure 4). This test was conducted to investigate whether the use of low-salinity water reduces the interfacial tension (IFT) between the displacing phase and oil. IFT is a key factor that is directly proportional to capillary force. Reducing capillary force will increase the capillary number, which can help achieve higher displacement efficiency.

An illustration of IFT measurements is shown in Figure 5 and the results for both formation brine and low salinity water are presented in Table 4. The results indicate that low salinity water slightly lowers the IFT value by half compared to formation brine, resulting in roughly double the capillary number. This improvement in the capillary number yields a slight reduction in the residual oil saturation, which is considered significant. Based on this, IFT reduction can be considered a possible contributor to the improvement of oil recovery during low salinity flooding.

Figure 4: a. KRUSS sinning drop tensiometer b. Vile containing oil droplet.

Figure 5: Oil droplet in formation brine and in low salinity water.

Table 4: Summary of IFT results for low-salinity SW and formation brine vs AS Crude.

Name	Formation	Low salinity	Unit	Description
σ	9.78 ±0.07	4.09±0.16	mN/m	Mean IFT
f rot	1499.5 ±0.3	1499.6 ±0.3	rpm	Rotational speed
T	22.8 ±0.1	23.2 ±0.4	°C	Sample temp.
T Heating	23.0 ±0.0	23.0 ±0.0	°C	Heating temp.
V	13.89 ±0.05	11.65 ±0.08	µL	Drop volume

3.2. Contact Angle measurements

Trim-ends from sample ZE1-3 were selected as representatives of the high-permeability limestone group (k = 15.5 md). Trim-ends from samples ZE2-9 (k = 34 md) and ZE2-2 (k = 5.4 md) were chosen to represent the dolomite high-permeability and low-permeability groups, respectively. The trim-ends were then cleaned of dust, weighed, and aged in crude and brine to represent the four groups on which an IOR experiment was performed. The cores were classified according to their rock type and permeability as follows:

- Group 1: Limestone, high permeability, aged in brine to introduce water wetness.
- Group 2: Limestone, high permeability, aged in crude to introduce oil wetness.
- Group 3: Dolomite, high permeability, aged in crude to introduce oil wetness.
- Group 4: Dolomite, low permeability, aged in crude to introduce oil wetness.

Table 5 presents the results of contact angle measurements for different cores. To assess the possibility of wettability alteration from contact angle measurements, Anderson's criteria for wettability was employed in this study as follows: 0 to 75° is considered water-wet, 75 to 115° is considered neutral, and 115 to 180° is considered oil-wet. As shown in Table 5, for the oil-wet group, the droplet has spread on the surface of the rock, indicating that the system is highly oil-wet and the contact angle could not be measured.

Table 5: Contact angle measurements.

ID	Group	Before Aging Intial condition	After aging + IOR	ID	Group	Before Aging Intial condition	After aging + IOR
ZE1-3	1			ZE2-9	3		No oil droplet observed
ZE1-3	2		No oil droplet observed	ZE2-2	4		No oil droplet observed

3.3. Phase Behavior Study

A phase behavior study was conducted by mixing equal volumes of AS crude and AS brine (right-hand side tube) and BU crude and AS brine system (left-hand side tube). The tubes were agitated for an hour to ensure complete mixing, and a static test was conducted by leaving the tubes in a vertical position. The number of phases was monitored as a function of time, as shown in Figure 6. The results indicated the immediate development of the emulsion phase in both tubes, and the size of the emulsion started to decrease with time, indicating an unstable emulsion phase. It took two hours for the emulsion to completely break down. Emulsion could be a factor in the recovery process, considering the experimental time, system pore volume, and the water injection rate of 1 cc/min. However, it is important to note that the lab scale is completely different from the field scale.

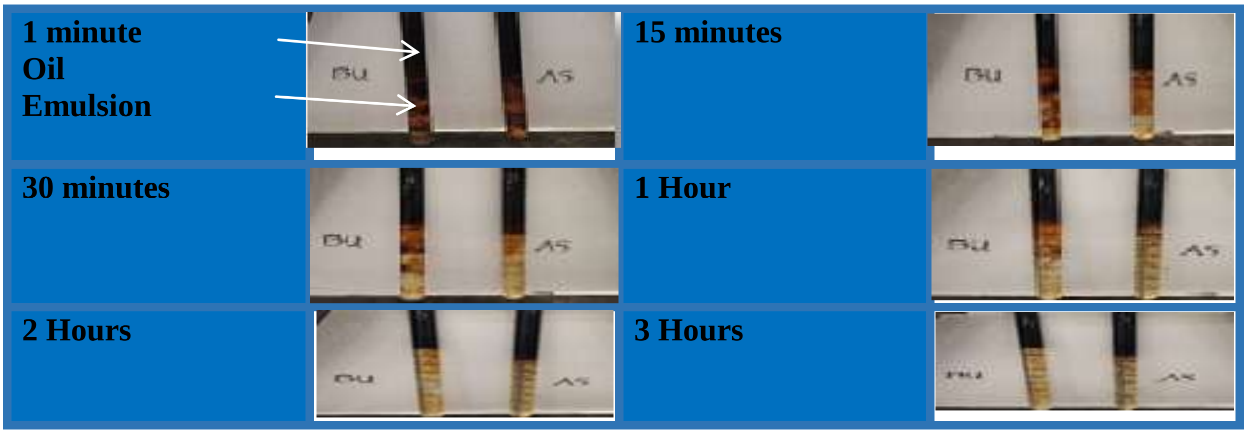


Figure 6: Phase behavior study of oil-brine systems.

3.4. Core flooding experiments

The core flooding apparatus consists of three major parts: the injection section, the core holding section, and the produced fluid section. Figure 7 displays a schematic diagram of the flooding system used in this project. All tests were conducted under reservoir conditions of pressure and temperature, except for the study of the rate effect on the optimum slug size. Fluid displacement was achieved by operating the syringe pump at a constant rate of 1 cc/min for all runs, except for the rate effect tests.

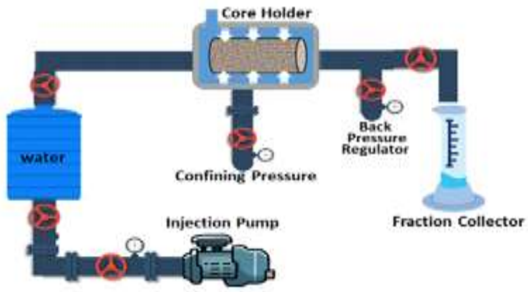


Figure 7: Schematic diagram of the core flooding system.

Eleven sets of core flooding experiments were conducted using different oils (AS and BH), different types of carbonate rocks (dolomite DL and limestone LS), oil-wet OW and water-wet WW pore environments, and high and low permeability HK and LK. Figure 8 presents the low salinity slugs flooding sets.

Each set consisted of 3 to 4 runs employing different slug sizes. The objective was to determine the optimum low salinity slugs in oil-wet and water-wet systems and to assess the effect of carbonate type LS and DL, and water injection rate on the optimum LS slug selection.

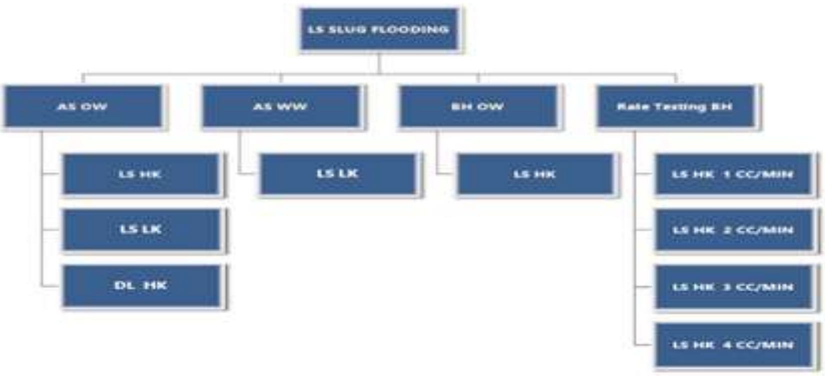


Figure 8: Low salinity slug flooding plan.

In the case of using AS oil to prepare oil-wet systems, three sets of experiments were conducted: two using low and high limestone permeability (LLK, HLK), and one utilizing a high dolomite permeability (HDK) system. One set of experiments was performed in a water-wet environment employing LLK and ASB oil. One set of experiments was also performed using BH oil and HL LS. To assess the effect of injection rate on the optimum LS slug size, one set was performed using BH oil and HK LS. In all runs, a specified LS slug (≈5000 ppm) was injected, followed by continuous flooding of high formation brine. In all runs that utilized AH crude, ASB brine (157,189 ppm) was used to displace the selected slug, and for BH crude runs, URD brine (171,647 ppm) was employed as the displacing fluid. Prior and post water injection cation concentrations (Ca, Mg, and SO4) were measured for the studied systems to assist in the interpretation of the performance of different floods and aid in defining the process mechanism. The pH of produced water, core petrophysical properties, oil density, and viscosity were measured prior and post flooding as well. All previous measurements were utilized in LS slugs flooding results analysis.

3.4.1. Slug size optimization, oil wet high permeability limestone.

Tests were conducted to study the effect of low salinity slugs flooding on limestone cores. Four tests were conducted using limestone cores numbered 2, 5, 10, and 18 as presented in Table 2. The cores were considered to have high permeability, with an average permeability of around 14 md. The floods were conducted in secondary mode (cores at irreducible water saturation) and at high pressures and temperatures. The following low salinity slugs (approximately 5000 ppm) were injected, followed by high formation brine (ASB 157,189 ppm): 10%, 20%, 30%, and 40% pore volume. The work employed ASB crude oil with an API of 38 degrees and a viscosity of 7.1 cp.

Figure 9 displays the performance of different low salinity slugs in an oil-wet environment for a high permeability limestone core. Results revealed a pleasant surprise: achieving a 90% oil recovery (displaceable oil) at such a low slug size of 10%.

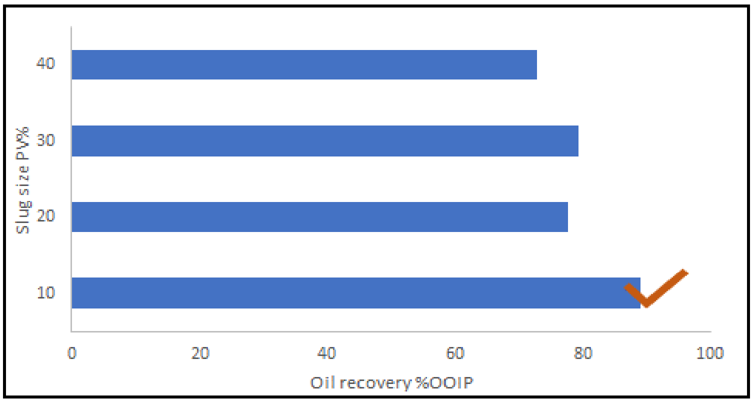


Figure 9: Optimum slug-size of oil-wet high-k limestone.

This performance is similar to, or higher than, any results reported for other EOR (chemical and miscible) processes. Increasing the slug size beyond 10% PV did not improve the process's performance, which indicates that a small pore volume of low salinity water is needed to develop the condition required for releasing the trapped oil. When released, the oil droplets coalesce to form an oil bank that collects the trapped oil as it moves toward the outlet. These results imply perfect process conditions in terms of lithology, wettability, injection brine concentration/composition, and oil composition. Based on that, we conclude that the optimum slug size is approximately 10% PV.

Multi-component Ionic Exchange (MIE) between brine containing potential determining ions (PDI) and carbonate grain surface reduces the strength of the ionic bond holding oil molecules to rock (Lager et al. 2008). Sulphate (SO42-) acts as a catalytic agent, reducing the carbonate surface's positive charge density by adsorbing to the grain. The decrease in grain electrostatic repulsive forces results in the co-adsorption of calcium (Ca2+). The reaction between Ca2+ and crude carboxylic groups breaks the attractive interactions between oil and grain, releasing adsorbed hydrocarbons, and altering wettability to a more water-wet state. This theory might explain the behavior of the oil-wet limestone HK group, as reported in Table 6. Calcium concentration decreased post-flood from 13,840 ppm to 12,340 ppm. MIE is not valid for most of the other carbonate groups in this study. Interestingly, Group 2 displayed the highest cumulative recovery compared to other groups.

Table 6: Effluent analysis of cations concentration.

NO	ID	Rock	pre-flood	k	Pre-flood concentration			Post-flood concentration		
					Ca	Mg	Na	Ca	Mg	Na
1	ZE1-8	LS	WW	high	13840	1604	44261	18600	2155	57247
2	ZE1-2	LS	OW	high	13840	1604	44261	12340	1485	38410
3	ZE2-18	LS	OW	high	13840	1604	44261	14720	1756	47282
4	ZE2-3	DL	OW	low	13840	1604	44261	13720	1669	43260

As the salinity of the flooding phase decreases, the concentration of crude oil naphthenic acids dissolved in the aqueous phase increases (Moradi et al., 2011). Naphthenic acids (NAs) are polar components that exist in crude oil and act as surface-active materials. They stem from the heteroatoms present in the heavier components. NAs are hydrophilic; they adsorb at the interface and dissociate to produce carboxylic anions and hydrogen ions. Table 7 records how the release of hydrogen in the aqueous phase resulted in a pH reduction in the effluent post IOR.

$$\boldsymbol{RCOOH_o \leftrightarrow RCOOH_{aq}}$$

$$\boldsymbol{RCOOH_{aq} \leftrightarrow RCOO^- + H^+}$$

Table 7: Post-IOR average pH readings.

Group	ID	Mineral	Pre-Flood	k	pH			Avg
	FW				7.02	6.97	9.95	8
1	ZE1-8	limestone	water-wet	high	7.34	7.36	7.33	7.3
2	ZE1-2	limestone	oil-wet	high	7.35	7.33	7.32	7.3
3	ZE2-18	dolomite	oil-wet	high	7.34	7.35	7.32	7.3
4	ZE2-3	dolomite	oil-wet	low	7.43	7.44	7.41	7.4

The acid number of the AS crude used in this phase is 0.07 KOH/g, which is very low. This probably contributes to the excellent performance of LS, as supported by Standnes and Austad (2000) findings. According to Yi and Sarma (2012), low salinity flooding is more efficient with heavier oils than with lighter oils. Heavier oils have a higher initial oil wetness, as the polar components absorb to the grain surface, meaning that an LSW slug has a higher chance of significantly altering wettability. The amount of carboxylic material is quantified by measuring the acid number. Standnes and Austad (2000) work revealed improved oil recovery and increased water wetness as the acid number decreased (carboxylic material increased).

The petrophysical analysis of the post-flood, presented in Table 8, revealed a reduction in permeability for sample ZE1-2 (Group 2). Fines migration is a mechanism that was initially proposed for LSWF in sandstone, but has been adopted by some researchers, such as Zahid et al. (2012) and Yi and Sarma (2012), to describe an increase in recovery for carbonates. Movable particles released during this process block some pore throats, diverting fluid flow to un-swept areas and increasing the microscopic sweep efficiency. Some researchers argue that this mechanism might be a more significant factor in improving oil recovery than wettability alteration (Lager et al., 2008).

Table 8: Change in petrophysical properties after IOR.

		Pre-flood Flood		**Post-flood Flood**		**Notes**	
Group	**Sample ID**	**Ø %**	**k md**	**Ø**	**k md**	**Ø**	**k(g)**
1	ZE1-8	20.5	11.6	15.2	13.1	decreased	increased
2	ZE1-2	18.7	17.1	16.5	6.5	decreased	decreased
3	ZE2-18	12.8	9.7	10.4	2.9	decreased	decreased
4	ZE2-3	10.2	4.1	13.5	18.7	increased	increased

3.4.2. Effect of wettability on the optimum slug size.

Four low-salinity slug flooding tests were conducted using water-wet limestone cores numbered 6, 7, 8, and 9, as presented in Table 2. The average permeability of the cores was around 10 md, which was considered a high permeability group in this study. The floods were conducted in secondary mode (cores at irreducible water saturation) and at high pressures and temperatures. The following low-salinity slugs (≈ 5000 ppm) were injected, followed by high formation brine (ASB 157,189 ppm): 10%, 20%, 30%, and 40% pore volume. The ASB crude oil, having an API of 39 degrees and a viscosity of 2.93 cp, was employed in this phase of the work.

Figure 10 presents the results of oil-wet and water-wet LS slug flooding. The water-set system has shown no significant improvement in oil recovery beyond a 30% PV slug size. A slug of 30% PV yielded an oil recovery equal to 58% of the oil in place. This indicates that low-salinity flooding works in a water-wet limestone environment. The results clearly demonstrate the effect of wettability on the optimum slug size and oil recovery. Oil-wet limestone reservoirs with reasonable permeability require a very small slug size and produce most of the oil in place during the low-salinity process by employing multi-mechanism to achieve that result. The water-wet environment for the same conditions required three times the optimum slug size of the oil-wet system. The limestone cores used in this study are pure (anhydrite-free) with an average grain density of 2.68 g/cc. Despite that, high oil recovery was observed, especially in oil-wet cores. Such results disagree with Austad et al. (2011) and Zahid et al. (2012), who reported no recovery improvement in anhydrite-free samples.

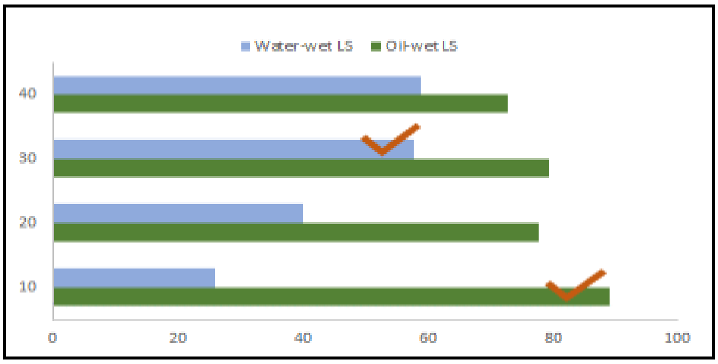


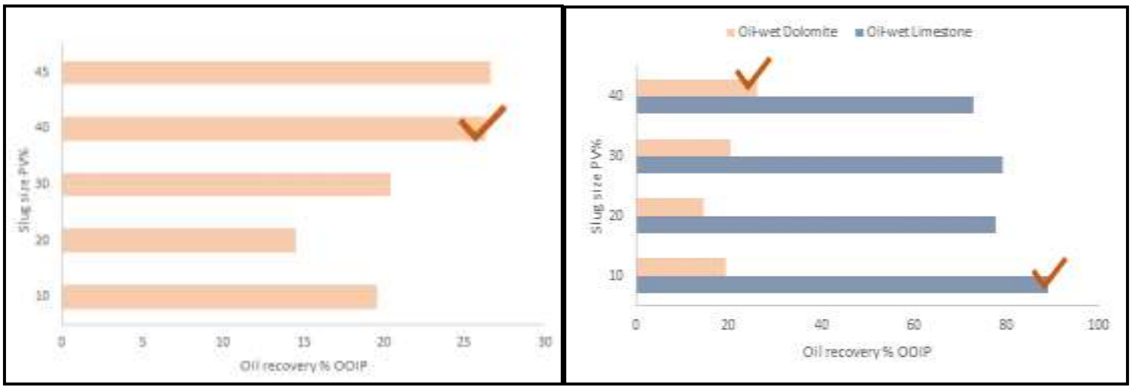
Figure 10: Optimum Slug-size of water-wet and oil-wet.

Effluent analysis of cation concentration in water-wet flooding resulted in a 34% increase in Ca2+ concentration, as presented in Table 6. According to Hiorth et al. (2008), the lower concentration of Calcium (Ca2+) in the low salinity seawater slug causes dissolution of Calcium Carbonates to restore equilibrium with the displacing phase. Calcite dissolution releases adsorbed crude polar components from the grain surface and alters wettability to a more water-wet state. In the water-wet environment, dissolution seems to play a greater role in the oil recovery mechanism, as water has direct contact with the surface of the rock. This conclusion is supported by the increase in permeability of the system after low salinity flooding, as shown in Table 8.

3.4.3. Effect of rock type on the optimum slug size

Two carbonate rock types, limestone and dolomite, were employed in this section after being aged in oil for four weeks to establish an oil-wet system in both rocks. Four slugs of low-salinity water were tested to determine the optimum size in each rock type. A complete analysis of the LS slug flooding of an oil-wet high-permeability system was presented in section 3.4.1. The same procedure and conditions of LS slug flooding have been applied to the dolomite slug flooding. Cores No. 1, 6, 17, 18, and 21 were employed to determine the optimum slug size for an oil-wet, high-k dolomite environment. The average permeability of the employed cores is around 11 md, as seen in Table 3. The following five slugs were used in this phase: 10, 20, 30, 40, and 45 PV%. Figure 11a displays the results of the five slugs used in this phase of the study. Results revealed a higher optimum slug size of 40 PV% for this system and an oil recovery of 26.4% of OOIP. The determined optimum size is in total agreement with Seccombe et al.'s (2008) conclusion. Seccombe et al. (2008) concluded that a slug-wise injection of 40% is the most effective and economical method of low-salinity flooding. They have stated that project economics will be significantly enhanced by injecting a slug of low-salinity water followed by high-salinity water, which reduces the amount of low-salinity project requirements.

The performance of low-salinity slugs in dolomite appears to be much lower than in limestone. Petrophysical analysis of the post-flood, as presented in Table 8, revealed a reduction in sample ZE2-18 (Group 3) permeability. Fines migration is a mechanism initially proposed for LSWF in sandstone, but has been adopted by some researchers, such as Zahid et al. (2012) and Yi and Sarma (2012), to describe recovery increases in carbonates.



a. Dolomite **b. Dolomite and limestone**

Figure 11. Effect of rock type on the optimum slug size.

Released movable particles can block some pore throats, diverting fluid flow to upswept areas and increasing the microscopic sweep efficiency. Some researchers argue that this mechanism may be a more significant factor in improved oil recovery than wettability alteration (Lager et al., 2008). In conclusion, as shown in Figure 11.b, rock type has a significant effect on the optimum slug size and the amount of oil recovery.

3.4.4 Effect of permeability on the optimum slug size.

Reservoir permeability is one of the factors that may play a role in the performance of LSWF. However, no evidence has been provided in the literature that correlates permeability with the performance of LSWF. The effect of permeability on LSWF has been ignored, and the consensus among researchers is that absolute permeability may have no effect on the application of LSWF. It is important to note that, to our knowledge, no sensitivity experiments have been performed to assess the effect of permeability on the performance of

LSWF. High and low permeability oil-wet dolomite cores were utilized to study the effect of permeability on the LS slug size optimization (Figure 12).

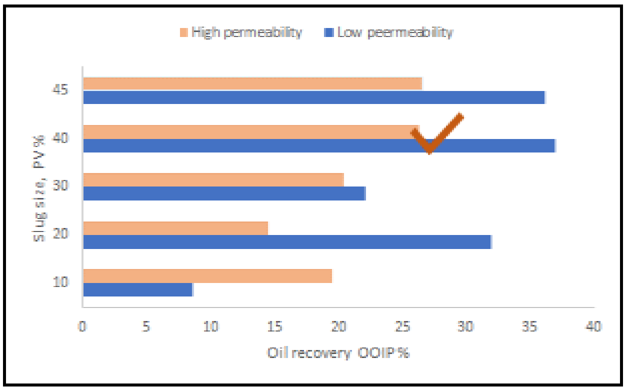


Figure 12: Effect of absolute permeability on the optimum slug size.

The results of high permeability dolomite cores are presented in section 3.4.3. Cores numbered 3, 8, 12, 16, and 22, with an average permeability of 2 md, were employed to determine the optimum slug size for the oil-wet low k dolomite environment. The following five different LS (low salinity) slugs were used to estimate the optimum slug for the low permeability dolomite oil-wet environment: 10, 20, 30, 40, and 45 PV%. The results indicated that permeability did not affect the optimum slug size determination as the optimum LS slug for both low and high permeability is around 40 PV%, as presented in Figure 10. These results are in line with the conclusions of Seccombe et al. (2008) regarding the optimum slug size requirement for low salinity flooding.

Contrary to normal results and to our surprise, low salinity slug performance in low permeability cores was significantly higher than in high permeability ones, as shown in Figure 12. The oil recovery obtained from the low permeability core (≈ 1md) is around 37% of OOIP (original oil in place), compared to the recovery from the high permeability core (≈ 7md), which is equal to 26.3%. Therefore, low salinity slug performs better in low permeability areas as the interaction between different fluids/rocks will take place much more easily and in a shorter time. The previous conclusion is supported by the data presented in Tables 6 and 8, which indicated a slight reduction in the Ca2+ concentration and an increase in the porosity and permeability in post flooding for the low permeability case, while the contrary was noticed for the high permeability case. These observations are strong clues to both MIE (multicomponent ion exchange) and dissolution mechanisms, as discussed in section 3.4.1.

3.4.5 Slug size optimization, BH oil wet high permeability limestone.

Four different slugs were employed to determine the optimum LS slug size, using BH reservoir crude and oil-wet, relatively high permeability LS cores. This work was performed to confirm the results obtained in section 3.4.1, with the only difference being the crude oil used. Although both crude oils have similar API and viscosity, the optimum slug size obtained was slightly different.

Figure 13 indicates that the optimum slug size for BH crude is relatively low, around 20 PV%, and the overall oil recovery is equal to 89.11% of OOIP. This is in line with the results obtained for AS crude, which showed an oil recovery of 89.04% of OOIP. These results confirm the conclusion stated in section 3.4.1, which points to the excellent applicability of small slug sizes in the case of oil-wet limestone reservoirs with reasonable permeability. The slight difference in the optimum slug size can possibly be attributed to the different oil composition and/or the different driving high salinity waters. Chavan et al. (2019) reported, based on their literature review, that no additional oil recovery could be obtained with a 10% PV slug, and that 30% PV is the smallest slug required for flow through the entire core plug. However, the results of our work clearly demonstrate that a slug of 10% or 20% PV performed exceptionally well, producing most of the oil in place, around 89% of OOIP. Therefore, the optimum slug size is a function of many parameters, and every case should be studied separately, without relying on general rules.

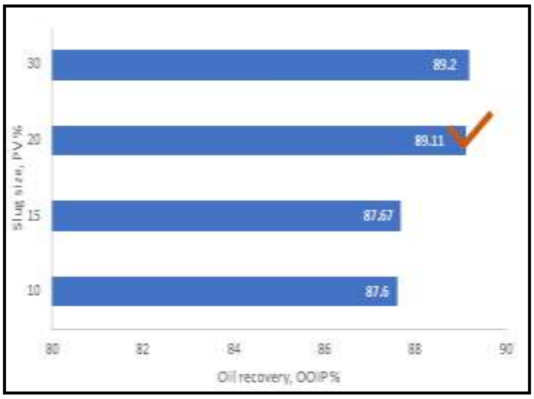


Figure 13: Oil recovery vs slug size, LS-OW AH oil -LSW-URD.

3.4.6. Slug flooding, secondary and tertiary flooding.

The secondary flooding condition refers to the injection of LS water at the irreducible water saturation (S_{wi}), whereas the tertiary condition means injection of LS water after high salinity brine. Zhang et al. (2007) and Agbalaka et al. (2009) have reported an improvement of oil recovery during low salinity flooding in both conditions. On the other hand, Rivet et al. (2010) and Nasrallah and Nasr-El-Din (2011) have reported a response to LSWF during the tertiary condition. In this phase, the response of low salinity slug flooding (20% PV) during the secondary and tertiary modes of flooding is assessed. Two similar oil-wet limestone permeability cores (≈ 8.8 MD) and BH crude were used in this phase. In both experiments (secondary and tertiary), URD water is employed as a driving brine. Figure 14 shows the results of both experiments. The results indicated a higher performance of LS slug flooding during the secondary mode as compared to the tertiary mode. Low salinity slug in the tertiary mode could achieve an extra oil recovery equal to 9% of OOIP (19% of remaining oil), which is on average almost equal to the incremental oil recovery obtained by surfactant (10% of OOIP) and also the recovery by miscible carbon dioxide flooding in the tertiary mode (10% to 11% of OOIP). Previous continuous LS core flooding experiment results showed a 37% higher oil recovery in the secondary mode as compared to the tertiary mode, as reported by Nande and Patwardhan (2022). These results are relatively close to our data for slug injection, which amounts to 43.5% higher oil recovery for the secondary over the tertiary mode.

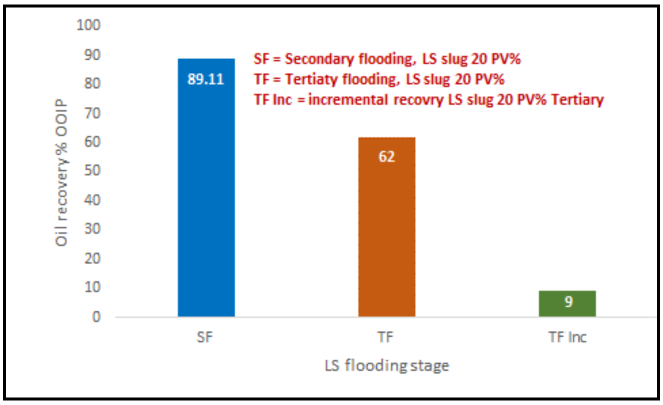


Figure 14: Low salinity slug flooding, second and tertiary modes.

3.4.7. Slug flooding, effect of injection rate

The effect of injection rate on the performance of low salinity water flooding is overlooked by most researchers. To correctly evaluate the IOR potential of injected brines, an analysis of the optimum injection rate to overcome capillary end-effects should be performed before conducting a core flood experiment (Tetteh et al., 2020). Four different injection rates (1, 2, 3, and 4 cc/min) were conducted on cores with permeabilities equal to 8.7, 8.8, 102, and 21 MD, respectively.

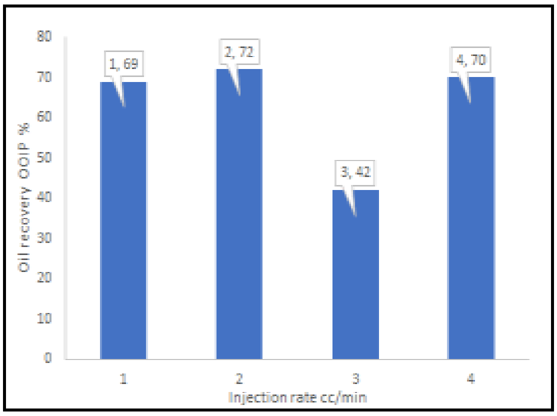


Figure 15: LS slug injection rate vs oil recovery.

All experiments were performed under the same conditions with respect to LS slug size, temperature and pressure, oil type, rock type, wettability, and driving water to focus on the effect of injection rate only. The following parameters were used throughout this phase: oil-wet limestone cores, BH and URD oil and water, respectively, and all experiments were performed at 77 °F and 300 psia. The results in indicated that the injection rate of the LS slug water influences the performance of the process. Based on the results presented in Figure 14, an injection rate equal to 2 cc/min could be considered the optimum rate for the studied system. The low performance displayed by the 3 cc/min injection rate can be attributed to the high absolute permeability of that core compared to the other cores. This result confirms the conclusion that increasing permeability decreases the performance of LS slug injection, as stated in section 3.4.4. In the selection of the optimum slug injection rate, a tradeoff should be considered between overcoming the capillary end-effect and the residence time required for completing different mechanisms associated with low salinity injection. A higher injection rate could result in a shorter residence time, and the system may not be able to complete the recovery process mechanism.

CONCLUSIONS

Based on the results obtained from this study, the following conclusions can be drawn:

1. The optimal low salinity slug size strongly depends on reservoir wettability, absolute permeability, lithology, and oil composition.
2. For oil-wet limestone with reasonable permeability and a low acid number system, additional oil recovery could be obtained with as low as a 10% PV slug, and based on that, the smallest slug required for the flow through the entire core plug is equal to 10% PV.

3. Lower low salinity slug sizes and higher efficiency are observed in the case of an oil-wet system compared to a water-wet system.
4. Higher oil recovery and a lower slug size requirement have prevailed in the case of limestone cores compared to dolomite cores with the same wettability (oil-wet).
5. In general, the LS slug displayed better oil recovery efficiency for a lower permeability system.
6. In the selection of the optimum slug injection rate, a trade-off should be considered between overcoming the capillary end-effect and the residence time required for completing different mechanisms associated with low salinity injection.

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CONFLICT OF INTEREST

The authors declare that they have no conflict of interest.

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