The effect of carbonate rock wettability on the performance of low salinity waterflooding: an experimental approach

Abdulrazag Zekri¹ · Hildah Nantongo¹ · Fathi Boukadi²

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Abstract

While the “low salinity waterflooding” (LSWF) has been praised for enhancing oil recovery from different core rocks, the performance of the technique in different wettability environments remains unclear. The consensus is that LSWF does not work well in water-wet carbonate oil reservoirs. The main research objective was to determine the effect of LSWF on the displacement efficiency (DE) in different wettability environments. Carbonate core flooding experiments on rocks with different wettabilities were performed at in-situ reservoir conditions using seawater as a “base water”. Seawater was sequentially diluted 10 to 50 times and spiked 2 and 6 times with sulfate. Following sequential flooding with four different waters, the DEs were measured for different wettabilities. Five different sequential brine floodings were performed on carbonate rocks. Results indicated that optimum low salinity water is a function of system wettability. Seawater ($\approx 50,000$ ppm) is the optimum brine for oil-wet and intermediate-wettability systems. Sequential flooding consisting of seawater followed by diluted seawater in a water-wet system yielded the highest DE of 88%. Besides, low-salinity brine followed by sulfate performed better in a water-wet environment than in oil- and intermediate-wettability systems.

Keywords Low-salinity water · Wettability alteration · Modified water · Core flooding · Sequential flooding · Displacement efficiency

Introduction

Incremental oil recovery has been attributed to wettability reversal in low-salinity water flooding (LSWF). In fact, it is currently widely accepted that wettability reversal has yielded lower contact angles in water. In fact, Mahani et al. (2015) observed lower contact angles for undiluted and diluted seawater while Agbalaka et al. (2008) reported that different cores became more water-wet when flooded with low salinity brine. In addition, Yousef et al. (2012) performed LSWF measurements under reservoir conditions and

demonstrated that diluted seawater could enhance water-wet properties of reservoir rocks. Through history matching and based on core flooding experiments originally reported by Chandrasekhar (2013), Al-Shalabi et al. (2014) also investigated production mechanisms under LSWF for carbonate rocks. In all these experiments, wettability alteration was shown to be a dominant mechanism under LSWF (Agbalaka et al., 2008; Al-Shalabi et al., 2014; Yousef et al. 2012). In other studies, reported by Zaeri et al. (2018), Amott (imbibition) tests, that were done on carbonate rock materials from Iranian petroleum reservoirs, yielded an optimum degree of dilution that led to maximum recovery.

Furthermore, LSWF-instigated incremental oil recovery may also be attributed to salinity gradients. Cumulative salinity gradients associated with injection of waters of different salinities may lead to diffusio-phoresis (joining) and mobilization of the isolated oil drops (Prieve and Roman 1987). Zaeri et al. (2018) have also confirmed that injecting batches of water with different salinities facilitates ion transport between the rock surface and brine, thus leading to wettability alteration and improved oil recovery. Additionally, it has also been reported that temperature does affect

✉ Hildah Nantongo
nhildah89@gmail.com

Abdulrazag Zekri
a.zekri@uaeu.ac.ae

Fathi Boukadi
fathi.boukadi@louisiana.edu

¹ Department of Chemical and Petroleum Engineering, United Arab Emirates University, P.O. Box 15551, Al-Ain, UAE

² Department of Petroleum Engineering, University of Louisiana, Lafayette, LA, USA

wettability alteration. For example, in studies performed by Schembre et al. (2006), the Amott wettability indices for carbonate and sandstone cores were measured. Authors indicated that increased temperature could change rock wettability from low- to intermediate- to strong-water wetness. Further still, Gomari and Hamouda (2006) have also reported that the increase in temperature does make calcite surface more water-wet thereby contributing to incremental oil recovery. In another study, Khilar and Fogler (1983) stated that a critical brine concentration of approximately 0.4 by wt% NaCl brines enhanced oil recovery in sandstones. According to these authors, decreasing the concentration below this value triggered clay destabilization and formation damage. In another report, a moderate increase in oil recovery was observed during the injection of low-salinity water with 0.2–0.5 by wt% NaCl (Morrow and Buckley, 2011). During the same year, Alagic and Skauge (2011), developed a correlation relating fine particle migration and wettability. These authors also indicated that fine particle migration did not take place during LSW injection in aged cores, but happened when unaged water-wet cores were used. This finding is in agreement with results reported by Mungan (1965) and Clementz (1982). In addition, Chandrashegaran (2015) concluded that an injected water salinity of 0.2 by wt% is the optimal concentration for most rock types.

Wettability alteration is not a separate mechanism; it is also caused by other micro-scale mechanisms (Katende and Sagala, 2019). These are surface ion exchange, surface charge change, double-layer expansion, and mineral dissolution. In this study, a number of other chemical/physical wettability reversal mechanisms, that may hypothetically increase oil recovery and displacement efficiency, were evaluated.

Material and methods

Fluids

A crude oil with an API gravity of 39.5° was filtered through a 5-mm filter paper prior to any laboratory application. No asphaltene precipitation was observed during the storage. The crude oil had an acid number of 0.07 mg KOH/g. The number was measured using the ASTM D664 standard titration procedure. The oil viscosity was measured using a rolling ball viscometer at 20 °C and the measured value was 2.93 cP.

Eleven brines were used in the core flooding phase of this project. These brines include the formation water (FW), the water that is currently injected in the reservoir (IW) and seawaters (SW) with different salinity and sulfate concentrations. Table 1 presents the composition of the waters utilized in this project. Diluted seawater solutions are classified as

Table 1 The composition of diluted and spiked brines used in the study

Ion	SW	SW/10	SW/50	SW×2 SO ₄	SW×6 SO ₄
Calcium	690	69	13.8	690	690
Sodium	18,680	1868	373.6	21,748	17,475
Magnesium	2132	213.2	42.64	2132	2132
Potassium	672	67.2	13.44	672	672
Bromide	<0.1	<0.1	<0.1	<0.1	<0.1
Zinc	<0.1	<0.1	<0.1	<0.1	<0.1
Phosphate	<0.1	<0.1	<0.1	<0.1	<0.1
Chloride	27,370	2737	547.4	17,450	15,450
Sulfate	3944	394.4	78.88	5916	17,748
Bicarbonate	123	12.3	2.46	123	123
Nitrate	0	0	0	0	0
Strontium	0	0	0	0	0
Carbonate	0	<0.1	<0.1	<0.1	<0.1
TDS (MG/L)	53,611	5361.1	1072.22	48,731	54,290

follows: SW/10 is a ten-time diluted solution, SW/50 is a 50-time diluted solution. On the other hand, spiked solutions are classified as follows: 2SO₄ is a SW with a sulfate concentration that has been spiked twice and 6SO₄ refers to a SW with a sulfate concentration that has been spiked six times.

The sequential core flooding experiments for intermediate-wettability oil reservoirs, conducted by Zekri et al. (2020), were repeated in this study in oil- and water-wet environments in order to assess the effect of carbonate rock wettability on the performance of low-salinity flooding. This study mainly focused on testing the seawater and its dilutions at different sulfate spiking. The formation water has a TDS of 157,488 with a density of 1.1074 and a viscosity of 1.2482 cp at ambient conditions. The high salinity water currently being injected in the reservoir under study has a TDS of 258,250 mg/l with a density of 1.1639 mg/l and a viscosity of 1.75 cp at ambient conditions. The brines used in the flooding were categorized, based on their dilution and sulfate spiking, into seven different sets. Brines' compositions are presented in Tables 1 and 2.

Core samples

Ten limestone carbonate core samples were selected from many core plugs. These Limestone core samples had an approximate diameter of 1.5" and were gray in color. Five were used in the water-wet experimental runs and five in the oil-wet runs. All the core plugs for water-wet reservoir experiments were saturated with formation brine then aged for a minimum of three weeks in formation water prior to the sequential LSWF. The selected core samples for the oil-wet experiments were initially flooded with formation brine, then flooded with Asab (AS) crude oil and aged in the same

Table 2 The composition of diluted brines and their spiked solutions used in the study

Ion	SW/10×2 SO ₄	SW/10×6 SO ₄	SW/50×2 SO ₄	SW/50×6 SO ₄	IW	FW
Calcium	69	69	14	14	19,763	13,840
Sodium	1265	1792	1764	2836	72,237	44,261
Magnesium	213.2	213.2	43	43	3569	1604
Potassium	67.2	67.2	13	13	1859	0
Bromide	<0.1	<0.1	<0.1	<0.1	1039	0
Zinc	<0.1	<0.1	<0.1	<0.1	<0.1	0
Phosphate	<0.1	<0.1	<0.1	<0.1	5	0
Chloride	1912	1620	1800	1250	158,518	96,566
Sulfate	3067	3394	2950	3604	268	885
Bicarbonate	12.3	12.3	2.46	2.46	43	332
Nitrate	0	0	0	0	4	0
Strontium	0	0	0	0	944	<0
Carbonate	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
TDS (MG/L)	6605.7	7167.7	6586.46	7762.46	258,249	157,488

oil for 3 weeks prior to sequential LSWF with the numerous brines.

Systems wettability measurements

Six diskettes were cut from one core. Three were saturated with formation brine. The water-saturated diskettes were also aged in the same brine for three weeks. The other three were saturated with reservoir oil. They were similarly aged in the same oil for three weeks. Aging was done at temperature and pressure of 90 °C and 200 psia. Water-saturated diskettes were placed in a glass beaker filled with formation brine. Oil droplets were later placed on the surface of the water-saturated diskettes. After 24 h, water–oil contact angles were measured. They were found to be at around 45°, confirming that the diskettes were water-wet. The oil-saturated diskettes were placed in glass beakers filled with formation brine for more than 24 h. No oil drops appeared on the surface of the diskettes. That confirms that the oil-saturated diskettes reached complete oil wetness.

Core flooding experiments

Core flooding was designed to assess the potential of water injection under dynamic conditions and in different wettability environments. Flooding experiments were considered to evaluate the effect of dilution and sulfate spiking on the DE. A series of five core flooding experiments were conducted (refer to Table 3). Every single core was flooded with a specific set of brines, sequentially, to eliminate the effect of variation in the rocks' petrophysical properties. An injection rate of 1 cc/min was used in all core floods. Table 4 presents the order of the injected brines for every core flooding experiment. All effluents were analyzed for pH, resistivity, turbidity, and total dissolved solids (TDS).

Table 3 Basic properties of the core plugs

Wettability	Sample	Water	Porosity
	ID	k (Md)	%
WW	18	20.60	11.00
	38	10.30	11.00
	24 S	11.30	13.00
	2	11.60	15.00
	8	12.20	16.00
OW	22	15.50	14.00
	2	10.99	12.00
	5	14.05	15.00
	22 S	12.00	13.00
	3	11.10	12.00

Table 4 Sequential order of brine injection

Sequential	Sequential order of brine injection		
	First	Second	Third
I	SW	SWX 2 SO ₄	SWX 6 SO ₄
II	SW/10	SW/10 X 2 SO ₄	SW/10 X 6 SO ₄
III	SW/50	SW/50 X 2 SO ₄	SW/50 X 6 SO ₄
IV	SW	SW/10	SW/50
V	IW	SW/10	

Results and discussion

Low-salinity recovery mechanism

Zekri et al. (2020) identified the dominant recovery mechanisms for low-salinity sequential flooding in intermediate-wet rock; namely rock dissolution and water-in-oil

emulsion. Results of that work will be used to compare with the performance of sequential brines in oil- and water-wet environments.

Water-wet system

Effect of sulfate concentration

The initial core flooding experiments used 18 cores with an initial water saturation of around 15.4%. The cores were flooded with SW first. SW was then spiked with twice and 6-times the sulfate concentration, respectively. Results of the sequential I flooding are presented in Fig. 1.

Sequential I flooding started with SW injection. It yielded a recovery of 78.50% of the OOIP after the injection of 10.6 pore volumes (PVs). Further water injection showed no improvement in oil recovery as the water cut remained constant. In order to evaluate the effect of sulfate, the injection system was changed to SWX2SO₄ (spiked seawater with twice the sulfate concentration). Injection was continued for up to 23.5 PVs. Spiked seawater yielded an enhancement of 2.2% in the displacement efficiency, DE. The displacement efficiency defined as follows:

$$DE = \frac{S_{oi} - S_o}{S_{oi}}$$

S_{oi} = Initial oil saturation @ the start of the flood.

S_o = Average oil saturation @ the end of the flood.

After a sequential flooding (with SW and then SWX2SO₄) for a total of 27.8 PVs, the flooding system was switched to

SWX6SO₄ (spiked seawater with 6 times the sulfate concentration). SWX6SO₄ yielded an additional 0.2% and the overall DE was estimated to be around 80.93%. Table 5 presents brines prior- and post-flooding properties. These results indicated that there is a slight increase in the pH of the produced SW as well as the SWX2SO₄. Post-flooding water analysis revealed a slight increase in total dissolved solids and turbidity. This indicates that a minor dissolution took place during the flooding process. Alteration of total dissolved solids TDS is most likely due to dissolution. The alterations were, however, minor and non-conclusive. The resistivity measurements of the effluents showed a slight decline. This is attributed to the increase in produced water salinity and confirms the conclusion drawn previously regarding the limited improvement of the DE caused by sulfate-spiked seawater flooding.

Effect of dilution

To study the effect of dilution on the displacement efficiency, a sequential IV flooding was performed (SW, 10-times diluted SW, and 50-times diluted SW). This flood was carried out using core sample 2. The results for the sequential flooding are shown in Fig. 2.

These results showed that the dilution of seawater has a significant effect on the DE of oil in a water-wet carbonate formation. The DE from SW flooding was estimated to be around 61.5% after the injection of 6.9 PVs. Ten-times and 50-times diluted seawater were then utilized. The DE improved by 21.9 and 4.6%, respectively. Total displacement efficiency of sequential IV mounted to around 88%.

Fig. 1 DE of sequential I flooding, water-wet system

Table 5 Properties of sequential I brines prior and post flooding, water-wet system

Effluent properties		SW		SW X 2 SO4		SW X 6 SO4	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	8.1	7.81	8.53	8.14	8.73	8.42
Total Dissolved Solids	mg/L	53,611	61,462	48,731	55,984	54,290	72,840
Resistivity	(Ohm-meter)	0.174	0.169	0.177	0.176	0.215	0.212
Turbidity	NTU	0	4	0	6	0	7

The improvement of the DE in water-wet environment is attributed to the emulsion mechanism. Water-in-oil emulsion increased substantially in water-wet systems, where oil is located in the middle of larger pores and is surrounded by water. On the other hand, in case of an oil-wet environment, oil spreads on the surface area of the rock and does not trigger emulsion. The results proved that low salinity works effectively in a water-wet carbonate rock environment due to the combined effects of wettability and dissolution. Experimental results of properties of the utilized waters, prior and post-flooding, are presented in Table 6. Data clearly demonstrated that dissolution during low-salinity flooding took place. That has been depicted in an increase of the pH, turbidity, and suspended solids, as well as in a reduction of resistivity of the effluent waters.

Effect of dilution and sulfate concentration

To study the effect of dilution and sulfate spiking, two sequential experiments (II and III) were performed using water-wet limestone rocks. In sequential II, 10-times diluted seawater and the diluted seawater spiked 2 and 6 times with sulfate were employed. The sequential flood consists of injecting SW/10, followed by SW/10*2SO₄, and then SW/10*6SO₄. Figure 3 indicated that sulfate spiking of 10-times diluted SW yielded slight improvement in the DE and the overall DE of this system estimated to be around 76.2%.

In sequential III, 50-times diluted seawater and the diluted seawater spiked 2 and 6 times with sulfate. The sequential flood consists of injecting SW/50, followed

Fig. 2 Displacement efficiency of sequential IV flooding, water-wet system

Table 6 Properties of sequential IV brines prior and post flooding, water-wet system

Effluent properties		SW		SW/10		SW/50	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	8.1	7.74	7.89	8.46	7.84	8.17
Total Dissolved Solids	mg/L	53,611	64,273	5361	21,745	1072	15,600
Resistivity	(Ohm-meter)	0.174	0.172	1.531	0.174	6.271	0.21
Turbidity	NTU	0	5	0	60	0	35

Fig. 3 Displacement efficiency of sequential II, water-wet system

by SW/50*2SO₄, and then SW/50*6SO₄. Experimental results, as depicted in Fig. 4, indicated that spiking of the 50-times diluted SW yielded insignificant improvement in the DE. Spiked seawater with twice and 6-times the concentration of sulfate added 0.5 and 0.4% to the DE, respectively. Results indicated that in low salinity environment, sulfate spiking did not play a major role in the improvement of the recovery mechanism.

Tables 7 and 8 present the brines properties for sequential II and sequential III, prior- and post-flooding. Data clearly demonstrated that dissolution had taken place. This is demonstrated by the increase of the pH, turbidity, suspended solids, hardness, and reduction of resistivity of the effluent waters.

High salinity-low salinity flooding

In sequential V, using core number 8, the injected water (high salinity $\approx 260,000$ ppm) and a 10-times diluted seawater (low salinity $\approx 7,000$ ppm) were used. To simulate the reservoir (under study) present condition, flooding was initiated with the injected water. Figure 5 presents the displacement efficiency of sequential V flooding. Results revealed that the injection of 10-times diluted seawater added a mere 0.37% to the DE. Overall displacement efficiency of this sequential was found at around 54.2% with an additional injection of 15.3 PVs.

To assess the dissolution phenomena prior- and post-flooding brines' properties were measured (see Table 9). The presented data confirm that dissolution took place during the low-salinity injection phase. A significant increase in the pH, TDS, and turbidity was observed during post-flooding. A

Fig. 4 Displacement efficiency of sequential III, water-wet system

Table 7 Properties of sequential II brines prior and post flooding, water-wet system

Effluent properties		SW/10		SW/10 X 2 SO ₄		SW/10 X 6 SO ₄	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	7.89	8.31	8.29	8.51	8.45	8.89
Total Dissolved Solids	mg/L	5361	23,789	6606	30,164	7068	34,847
Resistivity	(Ohm-meter)	1.531	0.931	0.212	0.215	0.258	0.249
Turbidity	NTU	0	62	0	70	0	44

Table 8 Properties of sequential III brines prior and post flooding, water-wet system

Effluent properties		SW/50		SW/50 X 2 SO ₄		SW/50 X 6 SO ₄	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	7.84	7.96	8.06	8.29	8.4	8.73
Total Dissolved Solids	mg/L	1072	22,160	6586	31,094	6663	36,231
Resistivity	(Ohm-meter)	6.271	1.821	0.231	0.255	0.28	0.268
Turbidity	NTU	0	62	0	43	0	31

Fig. 5 Displacement efficiency of sequential V flooding, water-wet system **Table 9** Properties of sequential V brines prior and post flooding, water-wet system

Effluent properties		IW		SW/10	
Parameter	Units	Before	After	Before	After
pH	Log(mol/L)	7.73	7.44	7.89	8.377
Total Dissolved Solids	mg/L	258,249	188,544	5361	36,687
Resistivity	(Ohm-meter)	0.062	0.061	1.531	0.512
Turbidity	NTU	6	13	0	62

66% reduction in the resistivity of produced water confirms that the dissolution mechanism was dominant during the low-salinity injection phase. No dissolution, however, was detected during the high-salinity flooding phase. The pH and TDS decreased while resistivity remained unchanged.

Oil-wet system

Five core samples were saturated with fresh water and then flooded with reservoir oil until a water cut of zero was achieved. Material balance was used to estimate irreducible

water saturations, S_{wi} . The core samples were then aged in oil for a period of 2 weeks. The samples were subsequently flooded with oil prior to sequential water flooding.

Effect of sulfate concentration

Core number 22S was injected with seawater first. The flood was followed by seawater with twice and 6-times the sulfate concentration. The brine injection was continued until oil ceased to flow. Figure 6 displays the displacement efficiency during the different stages of the sequential floods. Results indicated that the spiking of seawater with sulfate had no significant effect on the displacement efficiency. No change in the water endpoint relative permeability was observed. This indicates that no change in wettability took place. The post- and prior-flooding water properties are presented in Table 10. Results indicated that there was no significant change in the resistivity of the produced water. However, the acidity and pH were slightly reduced in all produced waters, especially in the ones that have been spiked with sulfate. As such, no conclusive evidence supports the possibility of rock dissolution in the oil-oil-wet environment.

Fig. 6 Displacement efficiency of sequential seawater and spiked SW flooding, oil-wet system

Table 10 Properties of SW flooding and spiked SW prior and post flooding, oil-wet system

Effluent properties		SW		SWX 2 SO ₄		SW X 6 SO ₄	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	8.1	7.68	8.53	8.52	8.73	8.3
Total Dissolved Solids	mg/L	53,611	59,517	48,731	62,364	54,290	69,204
Resistivity	(Ohm-meter)	0.174	0.161	0.177	0.171	0.215	0.206
Turbidity	NTU	0	5	0	8	0	8

Effect of dilution

To study the effect of dilution on the displacement efficiency in an oil-wet environment, sequential IV flooding was performed. The flooding sequence involved seawater, 10-times, and 50-times diluted seawater. Results indicated that dilution of seawater has a negative impact on the displacement efficiency in an oil-wet environment (see Fig. 7). Seawater alone produced better results thanks to dissolution and emulsion. These mechanisms were enhanced by a higher interfacial activity, as reported by Zekri et al. (2020). Researchers agree that ionic exchange phenomenon is the dominant production mechanism in oil-wet systems, where calcium ions are detached from the rock surface area carrying oil droplets and replacing them with magnesium ions. The sulfate ions are absorbed first on the limestone surface, neutralizing the charge of the rock surface. It is, therefore, expected to observe an increase in Ca^{2+} and a decrease in Mg^{2+} and SO_4^{2-} ions in the produced water during low-salinity flooding for the ionic exchange mechanism to take place. This did not manifest in the flood, as shown in the data presented in Figs. 7 (a, b, and c). This confirms that ionic exchange and wettability alteration did not take place.

Effect of dilution and sulfate concentration

Sequential II and III of the LSWF experiments in oil-wet environment consisted of using two diluted waters (10-times and 50-times) spiked with twice and 6-times the sulfate concentration. Cores number 2 and 6 were used for the 10-times and 50-times diluted seawater experiments, respectively. Figure 8 illustrates the DE achieved with seawater, 10-times diluted seawater, 50-times diluted seawater, and the injected water in the field under study. The optimum salinity for the oil-wet system was found to be at 7,000 ppm and further reduction in salinity did not improve the system DE.

Sulfate spiking was also tested in seawater flooding of oil-wet systems. Experimental results (as shown in Fig. 9) indicate that spiking of 10-times diluted seawater had a slight improvement in the DE, with an increment of 1.8%. The overall DE increased to 52.7%. Experimental results presented in Fig. 10 indicated that spiking of the 50-times diluted seawater had no significant improvement in the DE.

A slight rock dissolution, as observed from the endpoints of the effective permeability curves, could have taken place.

A slight reduction in the pH of the spiked and non-spiked 10-times diluted seawater was observed. An insignificant increase in the pH, however, was noted for the 50-times diluted seawater and its spiked waters (see Tables 11 and 12). The sulfate-spiked brines acted as neutral waters as no meaningful change in DE was observed for the oil-wet limestone rock.

High salinity-low salinity flooding

The final sequential flooding of brines is category V. Field water flooding followed by a 10-times diluted seawater was performed. This experiment was carried out using core number 3. The performance of sequential V is presented in Fig. 11 and brines' properties prior- and post-flooding are displayed in Table 13. The high salinity (case study field water) water flooding resulted in a DE of 50.6%. Subsequent injection of 10-times diluted seawater did not improve the DE of the system. As presented in Table 13, there was no significant change in the pH of prior- and post-flooding brines as the brines acted as neutral waters. The resistivity of the field water did not change, that of the 10-times diluted seawater, however, declined. Data also indicated that the TDS displayed a significant reduction during field water-flood and an increase during the 10-times diluted seawater flood. The results were attributed to the possibility of ionic precipitation during field water injection followed by dissolution into the low-salinity brine during 10-times diluted seawater flooding. No additional oil recovery was observed during the 10-times diluted seawater flood. This could be explained by the fact that as 10-times diluted seawater fills in the porous medium, mixing with high-salinity field water took place. Such mixing resulted in a high overall salinity that hindered the emulsion mechanism.

Effect of wettability on the performance of low salinity flooding

Results clearly indicate that the reservoir wettability has a significant effect on the displacement efficiency of low-salinity waterflooding. Surprisingly, diluted seawater in a water-wet system displayed higher performance compared

Fig. 7 **a** Ionic concentration of injection and production brines **b** Ionic concentration of injection and production brines **c** Ionic concentration of injection and production brines

Fig. 8 Displacement efficiency of seawater as function of dilution

Fig. 9 DE of sequential sea water diluted 10 times and spiked, oil-wet system

Fig. 10 DE of sequential SW diluted 50 times and spiked, oil-wet system

Table 11 Properties of SW/10 spiked prior and post flooding, oil-wet system

Effluent properties		SW/10		SW/10 X 2 SO4		SW/10 X 6 SO4	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	7.89	7.88	8.29	7.91	8.45	8.04
Total Dissolved Solids	mg/L	5361	35,632	6606	46,472	7068	38,940
Resistivity	(Ohm-meter)	1.531	1.023	0.212	0.209	0.258	0.243
Turbidity	NTU	0	54	0	60	0	37

Table 12 Properties of SW/50 spiked prior and post flooding, oil-wet system

Effluent properties		SW/50		SW/50 X 2 SO ₄		SW/50 X 6 SO ₄	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	7.84	8.12	8.06	8.16	8.4	8.44
Total Dissolved Solids	mg/L	1072	27,391	6586	28,810	6663	37,463
Resistivity	(Ohm-meter)	6.271	2.78	0.231	0.23	0.28	0.273
Turbidity	NTU	0	21	0	37	0	24

Fig. 11 DE of sequential IW and SW diluted 10, oil-wet system**Table 13** Properties of IW and SW/10 prior and post flooding, oil-well system

Effluent properties		IW		SW/10	
Parameter	Units	Before	After	Before	After
pH	Log(mol/L)	7.73	7.60	7.89	7.99
Total Dissolved Solids	mg/L	258,249	176,378	5361	22,747
Resistivity	(Ohm-meter)	0.062	0.063	1.531	0.274
Turbidity	NTU	6	10	0	49

to oil-wet and intermediate-wettability systems. Researchers agree that low-salinity flooding works better in carbonate formations (oil- and intermediate-wet) mainly through ionic exchange in the absence of clays. Low-salinity

waterflooding is more efficient in water-wet sandstones in the presence of clays. In such systems, emulsion and dissolutions play a major role in the improvement of the displacement efficiency since oil droplets occupy the larger pores and move to the middle of the pore space. Based on previous analysis, low-salinity 10-times diluted seawater flooding ($\leq 5,000$ ppm) is more efficient in a water-wet environment. Seawater, however, ($\approx 50,000$ ppm) produced the highest DE in oil-wet and intermediate-wettability systems. Figure 12 and Table 14 present the displacement efficiencies for seawater, 10-times and 50-times diluted seawater as well as injected field water.

Endpoint water relative permeabilities were measured and presented in Table 15, for different wettability systems using diluted seawater and field water. Figure 13 presents the results of water relative permeability at residual oil saturation for the studied cases. Craig's rule of thumb was used to qualify the system wettability. The rule stated that relative permeability to water at maximum water saturation is generally less than 30% for a water-wet system and greater than 50% for an oil-wet system (Craig, 1971). Based on that, for the oil-wet system, low-salinity water (10-times and 50-times dilution) shifted the system wettability to water-wet. Seawater, however, modified the rock wetness to intermediate most likely through dissolution.

As shown in Fig. 13 and Table 15, results indicated that dilution of seawater changed the rock wettability from intermediate- to oil-wet and that explains why DE was low for both cases.

Fig. 12 Displacement efficiency of SW, diluted seawater, for different wettability systems

Table 14 DE of different diluted and IW brines for oil-wet and water-wet systems

	Oil wet	Intermediate wet	Water wet
SW	57	71.7	61.5
SW/10	53	57.9	69.1
SW/50	52.4	40.8	65.4
IW	50.6	53.7	54

Table 15 Water-endpoint relative permeability for the different wettability systems

Brine	Oil wet	Intermediate wet	Water wet
SW	0.31	0.39	0.41
SW/10	0.14	0.54	0.37
SW/50	0.18	0.65	0.16
IW	0.26	0.46	0.43

The displacement efficiency of the sequential systems used in this study is affected by the system wettability as displayed in Fig. 14. The sequential IV

(seawater/10-times/50-times diluted seawater) is the optimum sequential system for oil- and water-wet systems. Sequential III (50-times diluted seawater, 50-times diluted seawater with twice the sulfate concentration, 50-times diluted seawater with 6 times the sulfate concentration) is the optimum sequential for intermediate wettability. In addition, spiking diluted seawater with sulfate did not show an improvement in the displacement efficiency of both oil- and water-wet environments. Overall, the optimum system for sequential injection is sequential IV in water-wet environment. Such system yielded a DE of 88% (refer to Fig. 14 and Table 16).

The displacement efficiency of high-salinity seawater followed by diluted seawater injection in water-wet systems is higher than what was reported in other enhanced oil recovery processes, such as chemical and miscible flooding. Experimental results indicated that sulfate spiking has no significant effect on the performance of the process when initiating sequential flooding with one of the following low-salinity waters (salinity $\approx$ 50,000, 5,000, or 1,000 ppm) followed with spiked seawater with twice and six-times the sulfate concentration.

Fig. 13 Endpoint relative permeability for the different wettability systems **Fig. 14** Displacement efficiency for sequential flooding as a function of system wettability

Table 16 DE of different sequential brine flooding for oil-wet, intermediate-wet and water-wet systems

	Oil wet	Intermediate wet	Water wet
Sequential I	57	40.7	80.09
Sequential II	54	58.12	76.2
Sequential III	52.7	75.09	66.3
Sequential IV	61.4	41.82	88
Sequential V	50.6	70	54.2

Conclusions

Based on this study's experimental results, it can be concluded that the performance of low-salinity flooding is a function of both recovery mechanism and rock wettability. Under the studied conditions, the optimum water salinity was estimated to be around 50,000 ppm for oil- and intermediate-wettability environment and 5,000 ppm for water-wet system. Results also indicated that sulfate spiking of low-salinity waters had no significant impact on the recovery efficiency. In a water-wet environment, sequential flooding IV (seawater/10-times/50-times diluted seawater) is the optimum displacement mechanism among the studied five sequential schemes; it yielded the highest displacement efficiency of 88%.

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Declarations

Conflict of interests The authors declare that they have no competing interests.

Data availability The data supporting the conclusions of this paper are included within the paper. Any queries regarding these data may be directed to the corresponding author.

Consent for publication Authors have agreed to submit it in its current form for publication in the journal.

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