



Comprehensive investigation of low-salinity waterflooding in sandstone reservoirs

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Abstract

Waterflooding has been applied for many years as secondary recovery method with no or little regard to the effect of the injected water salinity on oil recovery. However, in the last decade, there has been an increasing interest in understanding the effects of changing injected water salinity on reservoir performance. The potential of low-salinity waterflooding (LSWF) has been studied in sandstone reservoirs by numerous core-flooding experiments. These experiments have shown diverse results. This paper aims to investigate the effects of changing water salinity on oil recovery. A comprehensive review and analysis of the results of more than 500 core-flood experiments from published work were investigated to study the effects of several parameters such as clay content, clay type, and temperature on oil recovery. The relation between incremental oil recovery and sodium adsorption ratio SAR, and exchangeable sodium percentage (ESP) parameters which control clay swelling was illustrated. The analysis of the results revealed that there is an optimum composition and optimum salinity for waterflooding in secondary flooding stage. However, for tertiary flooding stage, the results showed that the controlling factor may be not decreasing the salinity but rather changing the salinity (e.g., either increasing or decreasing) with minor improvement in oil recovery. It was clear also that applying the optimum salinity in the secondary recovery stage is more effective than applying it in the tertiary recovery stage. This study aims to develop important guidelines for screening and designing optimum salinity for waterflooding projects in sandstone reservoirs.

Keywords Low-salinity waterflooding · Smart waterflooding · Enhanced oil recovery

Abbreviations

EDL	Expansion of double layer
EOR	Enhanced oil recovery
ESP	Exchangeable sodium percentage
F _m	Formation water
HS	High-salinity water
IFT	Interfacial tension
K _o	Oil permeability
K _w	Water permeability
LS	Low-salinity water
LSWF	Low-salinity waterflooding
MIE	Multi-component ion exchange
NMR	Nuclear magnetic resonance
OOIP	Original oil in place

SAR	Sodium adsorption ratio
TDS	Total dissolved salts
XRD	X-ray powder diffraction

Introduction

Bernard (1967) reported the first effect of applying low-salinity waterflooding. Later, numerous experiments have been conducted to study the effect of LSWF on oil recovery. Tang and Morrow (1997) showed that the oil recovery increased about 20% due to applying low-salinity water. Vledder et al. (2010) stated that the application of LSWF was economic for new fields. Webb et al. (2004) showed an increase in oil recovery due to reduction in the injected brine salinity from 80,000 to 30,000 ppm and then a significant increase after reducing it to 1000 ppm.

Alotaibi et al. (2010) observed completely opposite results after studying oil/water/rock interactions at different salinities and elevated temperature conditions on outcrops using synthetic formation brines, aquifer, and

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seawater under high-pressure conditions. They observed direct relationship between zeta potential and ionic strength. Patil et al. (2008) observed reduction in the residual oil saturation up to 20% and slight increase in the Amott–Harvey wettability index due to the decrease in the salinity on ten core plugs from Alaska North Slope field using three different water salinities (22,000, 11,000, and 5500 ppm TDS).

It should be highlighted that there is very limited published information on the low-salinity waterflooding pilot tests. Zeinjahromi et al. (2015) described a 7-year low-salinity water injection project comprising of eight injectors and 29 producers in Zichebashskoe field. He built numerical model (using fines migration concept) and compared the results of the model with the conventional waterflooding. He showed that low-salinity water injection resulted in less than 0.1% improvement in the incremental oil recovery compared with waterflooding using formation water. He explained that the failure reasons are due to applying low-salinity waterflooding after flooding by high-salinity water.

BP predicted the incremental oil recovery from tertiary LSWF in BP's offshore Endicott field to be in the range of 6–12% from the original oil in place (OOIP). The saturation change was measured using single well reactive chemical tracer tests (SWCTTs) in four wells. However, Shell applied the LSWF with 500 ppm in Omar oil field in Syria due to operational requirements. The analysis indicated that there was a decrease in the wettability from the original, which may be responsible for an expected incremental recovery of about 5–15% from the OOIP (Law et al. 2014).

Although the main mechanism for low salinity is still debatable, the proposed mechanisms are fines migration, surface roughening due to clay swelling, osmosis pressure effects, pH effects, salting in, multi-component ion exchange (MIE), double-layer effects, and the low-salinity chemical mechanism proposed by Austad et al. (2010).

Fines migration was suggested initially by Bernard (1967) and was accepted by Tang and Morrow (1999), Skauge et al. (2008), and Hadia et al. (2012). This suggestion was not agreed upon by Pu et al. (2008), Cissokho et al. (2010), Zhang et al. (2007), Lager et al. (2008a), Jerauld et al. (2006), Rivet et al. (2010), Shaker and Skauge (2013), and Amirian et al. (2017) who noticed an increase in the oil recovery without fines migration.

The increase in the water pH was expected due to adsorption/desorption of carboxylic material onto clay by Morrow et al. (1998) and McGuire et al. (2005) and was accepted by Piñerez et al. (2016). However, no direct relationship between pH and increased oil recovery was noticed by Lager et al. (2008b) and Rezaeidoust et al. (2009).

Surface roughening due to clay swelling was proposed by Marhaendrajana et al. (2018). He showed that the increase in surface roughness due to clays swelling modifies the surface water wetness. He also clarified that the determination of the clay swelling threshold is essential to minimize the effect of pore blocking.

Sandengen and Arntzen (2013) suggested that the increase in the osmotic pressure causes brine expansion and oil displacement. This mechanism was agreed by Sandengen et al. (2016), Fredriksen et al. (2016), and Fredriksen et al. (2017). However, Bartels et al. (2017) showed that the osmosis pressure can contribute in the incremental oil recovery, but it is not the primary mechanism of LSWF.

Salting in was predicted by Austad et al. (2010) and Rezaeidoust et al. (2009), due to an increase in the solubility of organic polar components in the aqueous phase. However, this mechanism was refused by Austad et al. (2010) as he did not observe any significant difference between the salinity conditions in the desorption process.

Multi-component ion exchange (MIE) evidence was proposed by Sposito (1989) and was accepted by Buckley et al. (1998), Seccombe et al. (2008), Lager et al. (2008a), Rezaeidoust et al. (2010), Mugele et al. (2016), and Arumugam et al. (2019). This suggestion was contradicted by Cissokho et al. (2010) and Austad et al. (2010) who performed low-salinity floods containing no divalent ions which resulted in increased oil recovery.

Double-layer effects were proposed by Ligthelm et al. (2009) who showed that a decrease in the water salinity will increase the thickness of the ionic double layer between the clay and oil interfaces which decreases the electrostatic repulsion force and increases the mineral surface zeta potential. Thus, a release of the organic material and wettability alteration can be achieved when injection of low-salinity brine is performed. Austad et al. (2010) showed that the double-layer effect is explained by the bridging of Ca^{2+} between the clay and oil, which both have negatively charged interfaces. However, it is not necessary with a bridge of divalent cations, since polar oil components can adsorb onto clay minerals without a bridge of divalent cations. Haagh et al. (2017) showed that double-layer expansion (DLE) is essential for LSWF effect, but it is not the reason behind wettability alteration.

The chemical low-salinity mechanism was proposed by Austad et al. (2010). He showed that both basic and acidic organic materials are adsorbed onto the clay together with inorganic ions, especially Ca^{2+} . Low-salinity waterflooding causes increase in the pH and causes desorption of ions with some of the adsorbed organic matter. He showed that the cation exchange capacity of the clay, which is in the order kaolinite < illite mica chlorite < montmorillonite, is essential for low-salinity effects.

There are three mechanisms commonly referred in the literature: double-layer expansion (DLE), multi-component ion exchange (MIE) and the chemical mechanism. However, surface roughening and osmosis mechanisms are still under investigation.

The above introduction shows that increase in oil recovery from low-salinity water injection is possible and can be explained by numerous mechanisms. However, there is no agreement on which mechanisms are important and can act under which conditions. This observation opens the door to optimization of salinity and composition of water for achieving higher recovery for different types of rocks. The work is a trial to analyze the results of several core-flood experiments from the literature in order to have guidelines to improve oil recovery in typical waterfloods by changing/optimizing water salinity and composition.

Database of previous flooding experiments

A database with results of more than 500 core-flood experiments was collected from the literature and used to provide additional insights in low-salinity waterflooding. Eighty plugs with more than 180 tertiary low-salinity waterflooding experimental runs and 75 plugs with more than 160 secondary waterflooding experimental runs are used in this analysis. (Twin plugs are considered as one plug.)

Table 1 and Fig. 1a, b show the histograms of the rock properties (porosity, permeability, and pore volume) of the 155 core plugs. The dataset covers range of the porosity from 5 up to 35%. More than 75% of the data has a porosity range of 15–25%. The maximum permeability recorded in the dataset was 4800 mD, while the minimum permeability was 5 mD. More than 35% of the data has a permeability range of 50–100 mD. From 155 plugs of dataset, only 42%

Table 1 Summary of core-flood experiments results collected from the literature

References	Type	No. of plugs	PV (cc)	Clay (%)	Por. (%)	Perm (mD)	Kaol.	Albite	Incr. oil recovery, % OOIP
Agbalaka et al. (2008)	Sec.	27	4–5	NA	16–30	1–212	NA	NA	6–20
	Ter.	6	4–5						2–20
Pu et al. (2010)	Ter.	7	7–16	NA	10–19	7–300	NA	NA	0–8
Hadia et al. (2011)	Ter.	13	11–25	3–7	12–25	11–4800	1.5–6	0	0–15
Rezaeidoust et al. (2009)	Ter.	7	NA	7–16	NA	3–17.5	3.5	0	0–6
Mjøs (2014)	Sec.	Twin	15–19	NA	21–25	NA	NA	NA	0
	Ter.	6							0–5
Zekri et al. (2011)	Sec.	5	NA	NA	9–18	2–162	NA	NA	0–10
Shehata and Nasr-El-Din (2014)	Sec.	Tw	27–110	6–22	18–20	NA	2–6	0	4–16
	Ter.	8							0–7
AlQuraishi et al. (2015)	Ter.	3	45	NA	22	77–314	NA	NA	1–10
Nasralla et al. (2011)	Ter.	25–31	11	18	66–95	5	0	25–31	0
	Sec.	8 Tw	25–31	11	18–19	66–95	5	0	20
Ashraf et al. (2010)	Sec.	12 Tw	NA	NA	18–19	76–183	NA	NA	4–11
Piñerez et al. (2016)	Ter.	2	22–23	43	20	22–48	0	32	5–9
	Sec.	2 Tw							10
Hosseinzade et al. (2016)	Sec.	2 Tw	113	8	15	270	0	1	10
Nasralla and Nasr-El-Din (2011)	Sec.	13 Tw	30–32	14	17–19	88–137	5	0	3–10
Hadia et al. (2012)	Ter.	4	15	19	14–15	16–17	6.5	6.5	0.1–3
Fjeldo et al. (2012)	Ter.	2	13	13	28	164	NA	NA	5
	Sec.	2 Tw	12	13	27	99	NA	NA	7
Nasralla and Nasr-El-Din (2012)	Sec.	4	106	NA	19	77–100	NA	NA	10
	Ter.	1							0
Alagic and Skauge (2010)	Sec.	4 Tw	22	NA	NA	650	NA	NA	5
Shaker and Skauge (2012)	Ter.	5	32		19–25	110–2200	NA	NA	0–2
Callegaro et al. (2013)	Ter.	3	8–27		5–16	0.5–273	0	5	8–8.5
Zeinijahromi and Bedrikovetsky (2013)	Sec.	3	38	NA	19	90	NA	NA	8–12
Siyambalagoda and Thyne (2011)	Ter.	12	6–18	NA	7–21	4–267	NA	NA	0–6
Ramanathan et al. (2015)	Sec.	4 Tw	406	13	18	78	6	3	(–6)–19

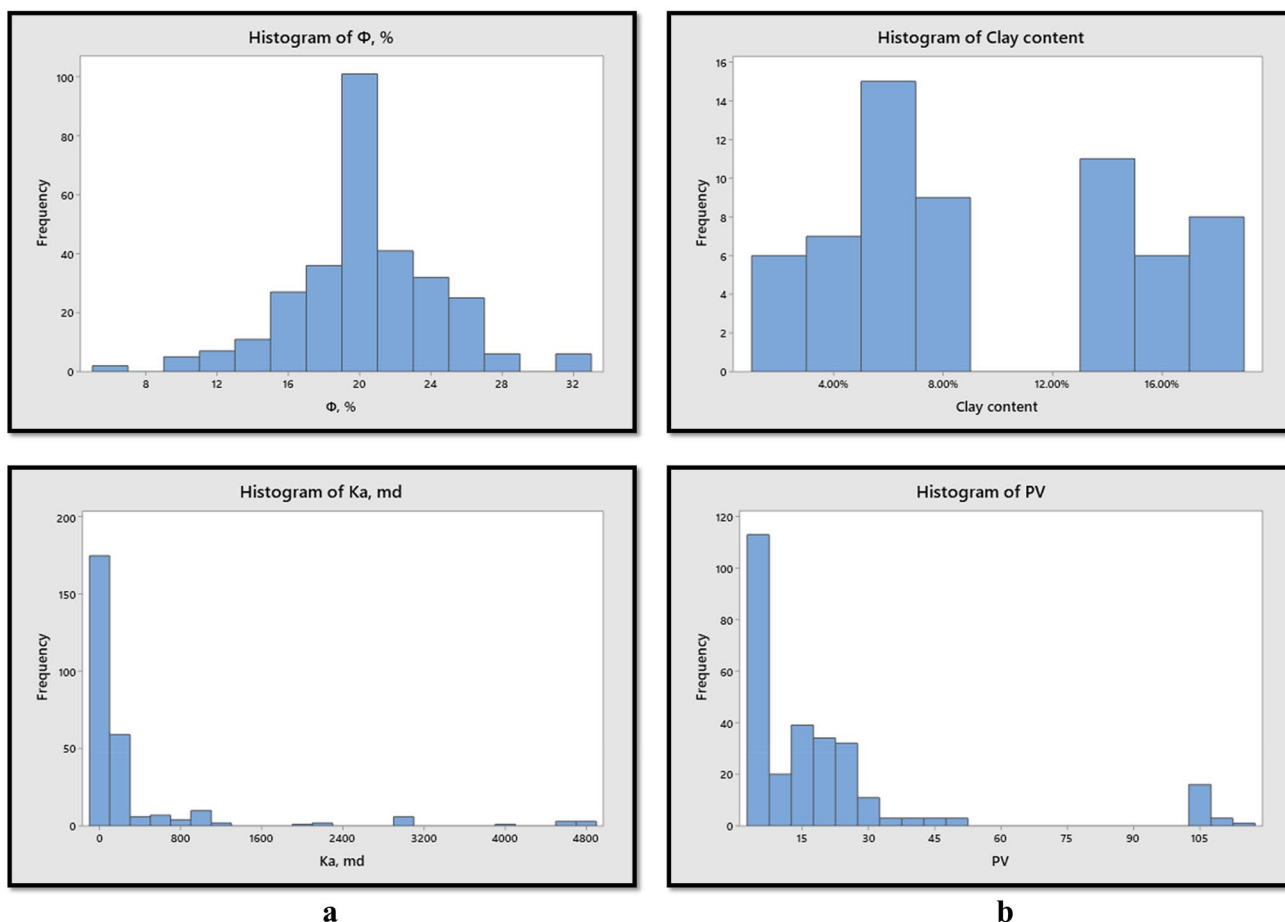


Fig. 1 **a** Histograms of porosity and permeability of the plugs from the literature. **b** Histograms of clay content and pore volume of the plugs from the literature

of the plugs has a description of the clay content. More than 50% of data has clay content less than 10%, while 5% of the data has more than 20 wt% clay content. More than 80% of the plugs had pore volume less than 30 cm³.

As shown in Table 1, the results from these waterflooding experimental runs indicated that the maximum additional oil recovery due to applying low-salinity waterflooding compared to high-salinity waterflooding in tertiary stage was about 15% of the OOIP, while the maximum additional oil recovery in secondary stage was about 20% of the OOIP. Figures 2a–d and 3a–d show the additional oil recovery versus permeability, clay content, kaolinite percentage, and low salinity (ppm) in the tertiary and secondary stages, respectively.

Discussion

Analysis devices and test methods

Table 2 presents the flooding devices and measurement methods which were used in the previous studies. Three

methods have been used to conduct the flooding experiments in the secondary and tertiary stages. The first procedure was core flooding using liquid pump, piston cell, core holder, oven, glass beret, and computer-controlled system. The second procedure was the spontaneous imbibition method. In this method, the flooding was carried out by displacing the fluid with a pump in a sealed core holder. The volume of the displaced fluid could be measured directly or determined by weight measurements. The third procedure was carried out using micro-model. It was performed using micro-plugs, sand packs, or glass model with clay. Oil recovery was measured using micro-computer tomography (micro-CT).

Many methods were used to investigate the behavior of the wettability alteration due to the LSWF. The measurements were carried out using solid substrate. The contact angle was measured by drop shape technique using contact angle meter, digitizing camera, or scanning electron microscopy. Zeta potential is the potential difference between the dispersion medium and the stationary layer of fluid attached to the particle. It is measured by a zeta potential analyzer. The pH was measured using pH meter. However, the

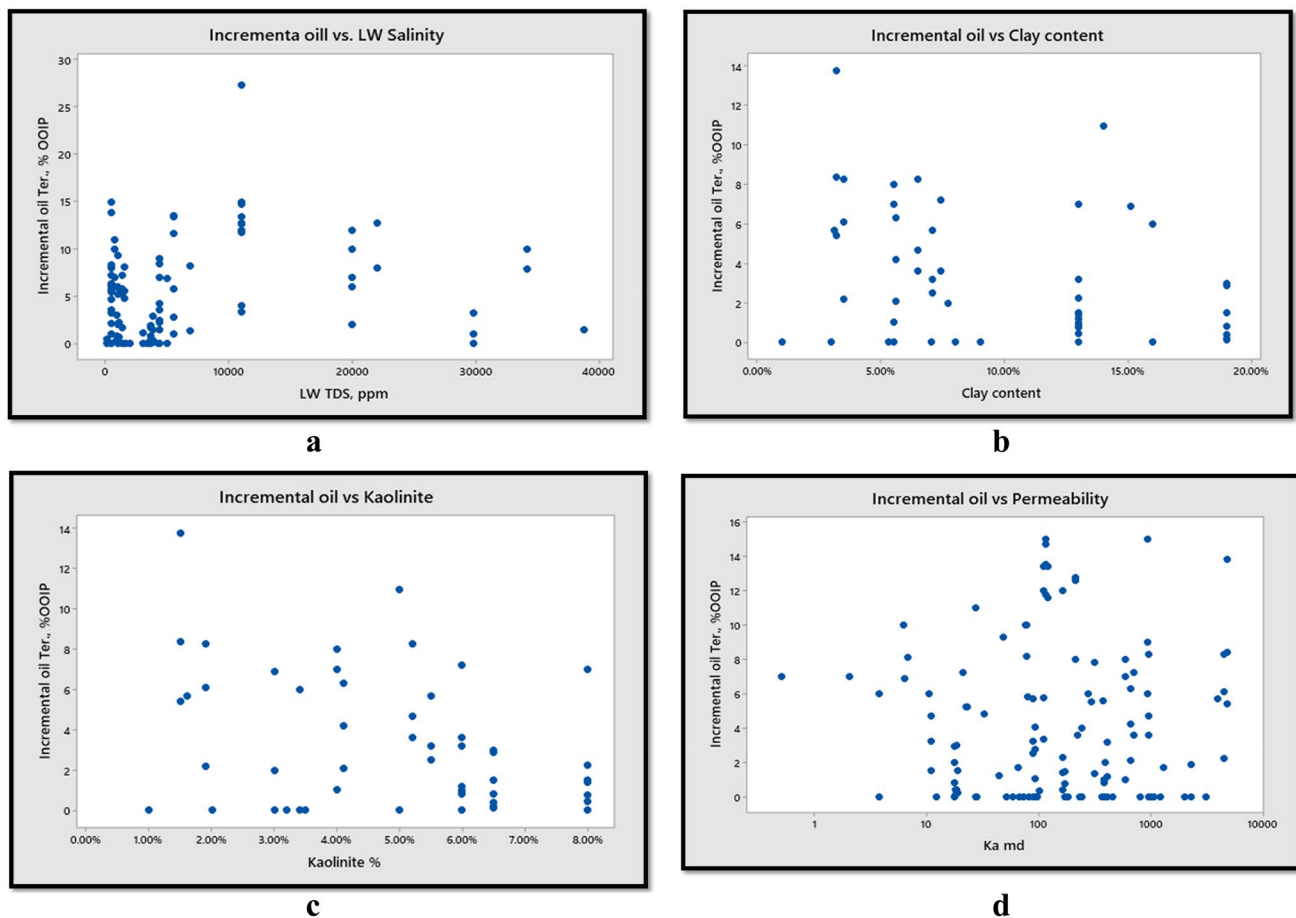


Fig. 2 **a** Tertiary incremental versus LW salinity of the literature data. **b** Tertiary incremental versus clay content of the literature data. **c** Tertiary incremental versus kaolinite of the literature data. **d** Tertiary incremental versus permeability of the literature data

interfacial tension was measured using tensiometer. Moreover, the wettability index was measured using Amott–Harvey method.

Bartels et al. (2017) used micro-model made of glass together with clay as a bulk of sandstone rock to study the effect of LSWF on the contact angle. He showed wettability modification as an effect of LSWF. However, Ashraf et al. (2010) performed core-flooding experiments for different wettability Berea cores at room conditions. The results showed increases in oil recovery as wettability changes from water- to neutral-wet conditions. Later, Shehata and Nasr-El-Din (2015) performed spontaneous imbibition and core-flooding tests to study the effects of divalent cations during LSWF. The injected water with divalent cations gave oil recovery higher than the injected water without divalent cations. However, Fjelde et al. (2012) performed waterflooding using three different water salinities for sandstone plugs with high clay content. They documented that changing of wettability to become less water wet during injecting formation water and high-salinity water. Aghaeifar et al. (2015) carried out a set of core-flooding experiments at high temperatures,

Tres > 100 °C, and at high FW salinities ~200,000 ppm. No incremental oil recovery was shown in this condition for LSWF. Shehata and Nasr-El-Din (2014) performed a set of core-flooding experiments in addition to measuring Zeta potential, X-ray powder diffraction XRD, pH, and nuclear magnetic resonance (NMR). They concluded that the average pore throat radius affects significantly in LSWF during secondary stage.

Salinity range for the LSWF applications

Varying opinions exist in the literature regarding the optimum water salinity range that can improve oil recovery. One study proposed water salinity less than 6000 ppm to show additional recovery. The experimental work in this previous study indicated that the optimum salinity was between 1000 and 2000 ppm (Rotondi et al. 2014). In the work of Chavan et al. (2019) and Morrow and Buckley (2011), they recommended water salinity less than 5000 ppm in laboratory tests and less than 3000 ppm in field tests to notice additional oil recovery.

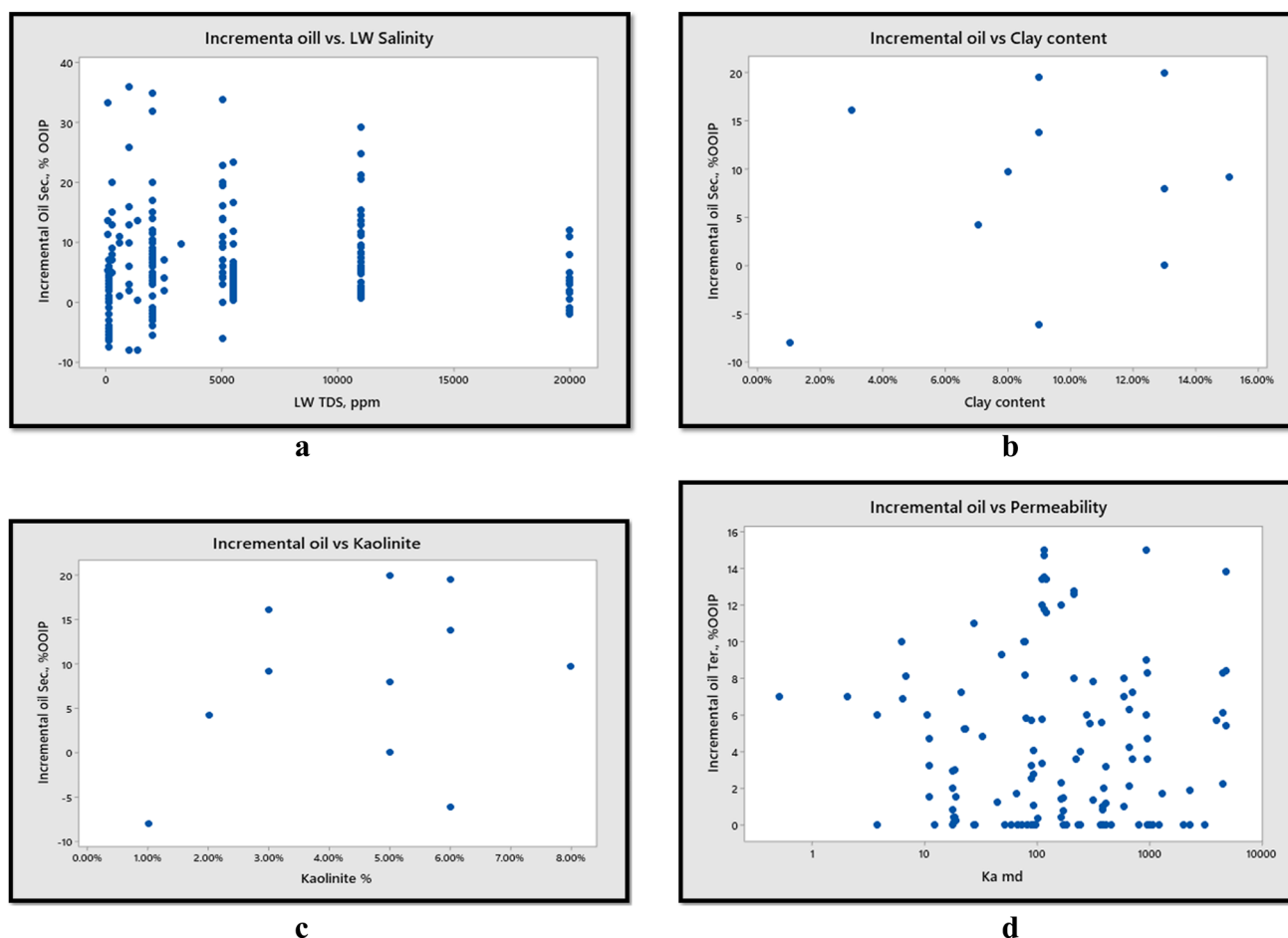


Fig. 3 **a** Secondary incremental versus LW salinity of the literature data. **b** Secondary incremental versus clay content of the literature data. **c** Secondary incremental versus kaolinite of the literature data. **d** Secondary incremental versus permeability of the literature data

However, the reviewed literature showed diverse results. Figure 2a shows the ranges of salinities with oil recovery in the tertiary stage. It is clear from Fig. 2a that the additional oil recovery was achieved using salinities up to 35,000 ppm. In addition, some experiments did not show any additional oil recovery even when using water salinities less than 5000 ppm. The maximum oil recovery due to applying LSWF in the tertiary stage was 15% at salinity less than 11,000 ppm as recognized by Hadia et al. (2011). The incremental oil recovery was less than 10% when applying LSWF of a salinity higher than 20,000 ppm.

Nasralla et al. (2011) and others concluded that low salinity in tertiary stage could be useless. Piñerez et al. (2016) showed that at least 2–8 PV is needed to notice improvement in oil recovery in the tertiary stage. Mjøs (2014) applied flooding with high water salinity after low water salinity and obtained additional recovery. The results reveal that changing salinity of injected water, either decreasing or increasing, may cause additional oil recovery in the tertiary stage.

Figure 3a shows additional oil recovery from WF in the secondary stage. High oil recovery was shown using salinities more than 10,000 ppm. The highest recorded incremental oil recovery was 33% OOIP at salinity less than 100 ppm. The incremental oil recovery reached 30% when applying low salinity higher than 10,000 ppm. Moderate LSWF (average 3000 ppm) shows relatively better incremental recovery (up to 25%).

Wei et al. (2017) and Mjøs (2014) showed lower recovery with ultra-low-salinity brine compared to low-salinity brine. Applying non-optimum water salinity even if it is LSWF can give less oil recovery.

Shehata and Nasr-El-Din (2014) and Fjelde et al. (2012) showed that applying optimum salinity gave less potential in the tertiary stage compared with applying it in the secondary stage in all plugs. In another study, Sandengen et al. (2011) showed insignificant incremental oil recovery in tertiary core floods after injecting of 2–3 first pore volumes. However, Piñerez et al. (2016) showed higher incremental oil recovery

Table 2 Flooding devices and measurement methods of the previous experimental studies

Paper	Sample type	Flooding devices			Wettability indication methods				
		Core flooding	Micro-model	Imbibition	pH	IFT	Contact angle	Zeta potential	Others
Piñerez et al. (2016)	Plugs	✓			✓				
Hosseinzade et al. (2016)	Micro-plug		✓			✓			
Shabaninejad et al. (2017)	Micro-plug		✓						
Keogh et al. (2017)	Sand packs		✓						NMR
Li et al. (2017)	Sand packs	✓				✓	✓		
Wei et al. (2017)	Plugs				✓				
Shaker and Skauge (2013)	Plugs	✓							
Mjø̄s (2014)	Plugs	✓				✓			
Agbalaka et al. (2008)	Plugs	✓							
Alagic and Skauge (2010)	Plugs	✓			✓				
Farooq et al. (2011)	Substrates						✓		
Fogden (2011)	Substrates				✓		✓		✓
Hadia et al. (2012)	Plugs	✓			✓				
Zekri et al. (2012)	Plugs	✓					✓		
Lebedeva and Fogden (2011)	Sand packs						✓		✓
Lu et al. (2017)	Substrates						✓		✓
Navrátil (2012)	Plugs	✓			✓				
AlQuraishi et al. (2015)	Plugs	✓				✓	✓		✓
Sandengen et al. (2011)	Plugs	✓			✓				
Alotaibi et al. (2010)	Substrates					✓	✓		✓
Ashraf et al. (2010)	Plugs	✓							Amott
Austad et al. (2010)	Plugs	✓			✓				
Pu et al. (2010)	Plugs	✓		✓					
Facanha et al. (2017)	Substrates						✓		
Shehata and Nasr-El-Din (2014)	Plugs	✓				✓	✓		✓
Shehata and Nasr-El-Din (2017)	Plugs	✓		✓	✓				✓
Fjelde et al. (2014)	Plugs	✓							
Zeinijahromi and Bedrikovetsky (2013)	Plugs	✓							
Shaker and Skauge (2012)	Plugs	✓		✓					Amott
Callegaro et al. (2013)	Plugs	✓							
Mamonov et al. (2017)	Sand packs			✓					
Nasralla and Nasr-El-Din (2014)	Plugs	✓					✓		✓
Mehana et al. (2017)	Plugs			✓		✓	✓		
Nasralla et al. (2011)	Plugs	✓							
Hadia et al. (2011)	Plugs	✓							Amott
Gamage et al. (2011)	Plugs	✓			✓				
Fjelde et al. (2012)	Plugs	✓			✓				
Nasralla and Nasr-El-Din (2011)	Plugs	✓							✓
Miyauchi et al. (2017)	Plugs	✓			✓		✓		
RezaeiDoust et al. 2010	Plugs	✓							
Mohamed and Alvarado (2017)	Plugs and substrates			✓		✓	✓		✓
Kakati et al. (2017)	Substrates					✓	✓		

with about 10% of the OOIP in the application of the LSWF in the secondary stage than those in the tertiary stage.

Fjelde et al. (2012) revealed that the repulsive force caused by LSWF in the tertiary stage is not enough to sweep trapped oil due to the absence of continuous oil film after injecting of high-salinity water. Furthermore, Sorop et al. (2013) showed that LSWF in secondary stage allows time for producing oil bank before the downfall of field life. In addition, changing of the formation fluids pH and salinity by injection of high water salinity decreases the effects of LSWF.

Effect of water composition

Robertson (2007), and Chavan et al. (2019) showed that there was an optimum composition of LSWF. However, limited information is available on how to determine the optimum salinity and composition for a particular rock. Hosseinzade et al. (2016) performed experiments by applying LSWF with the same salinity and different compositions. He observed that the LSWF with $\text{Ca}^{2+}/\text{Na}^+$ ratio of 0.005 resulted in higher recovery than the one with NaCl only.

Nasralla and Nasr-El-Din (2011) reported that changing composition from 5000 CaCl_2 to 5000 NaCl gave 7% more recovery, which means also that there is an optimum composition. They explained that LSWF with high concentration of NaCl might give higher oil recovery than with low concentration of CaCl_2 or MgCl_2 . They showed that NaCl injection may not be strongly efficient with the formation brines containing high concentrations of divalent cations unless several pore volumes of NaCl are injected and dilution of the formation brine is achieved.

Haagh et al. (2017) showed a decrease in the contact angle on muscovite due to reduction in the divalent cation concentration to zero. In addition, negligible effect in the contact angle was noticed after decreasing ion strength without changing divalent ion concentration. Mugele et al. (2016) performed a series of experiments to study the effects of pH and ion content during LSWF. He showed that the salt content of injected water and concentrations of divalent ions have a strong effect on the wettability.

Tchistiakov (2000) attributes the effect of the LSWF to decreasing clay stability in the sandstone which forces the release of the monovalent cations from the clay surfaces to diffusion layers around the clay particles and changing the rock wettability.

Bourrie (2014) showed that sodium adsorption ratio (SAR) and exchangeable sodium percentage (ESP) are the key concept to explain swelling of clay minerals during irrigation.

The sodium adsorption ratio (SAR) is defined as:

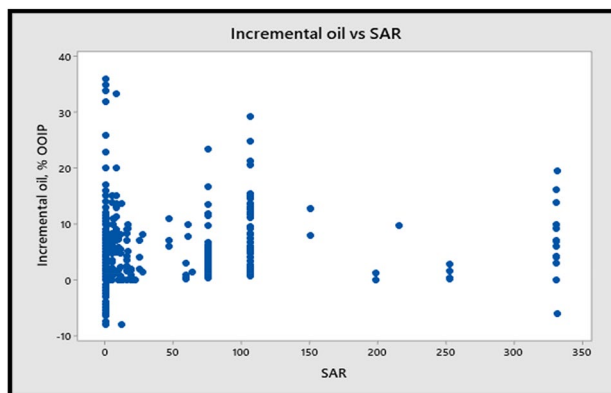
$$\text{SAR} = \text{Na}^+ / \sqrt{(\text{Ca}^{+2} + \text{Mg}^{+2})/2}.$$


Fig. 4 Relation between sodium adsorption ratio (SAR) and additional oil recovery

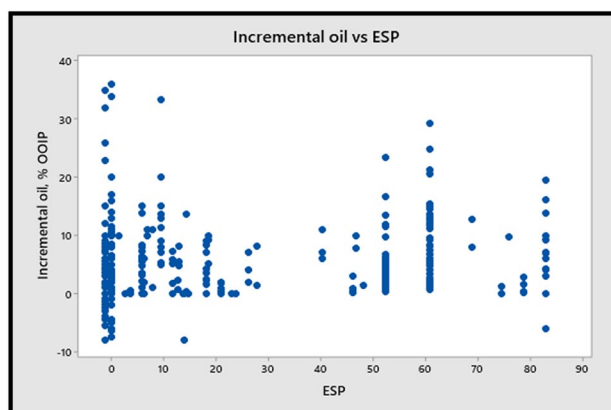


Fig. 5 Relation between the exchangeable sodium percentage (ESP) and additional oil recovery

Exchangeable sodium percentage (ESP) can be calculated from this correlation:

$$\text{ESP} = 100 * (0.01475 * \text{SAR} - 0.0126) / (1 + (0.01475 * \text{SAR} - 0.0126))$$

As clay is the role player in LSWF effect, Figs. 4 and 5 show the relation between SAR, and ESP versus incremental oil recovery. There is no consistent relation that can be extracted from the figures.

In addition, the relation between $\text{Ca}^{+2}/\text{Na}^+$ ratio and incremental oil recovery is shown in Fig. 6. The figure reveals the more incremental oil recovery when the ratio $\text{Ca}^{+2}/\text{Na}^+$ is less than 0.04.

Furthermore, Nasralla and Nasr-El-Din (2011) reported that reducing the original pH from 7.3 to 4.8 resulted in changing the interfaces from high negatively charged to weak negatively charged for both the oil/brine and rock/brine and hence a reduction in oil recovery. This means that there

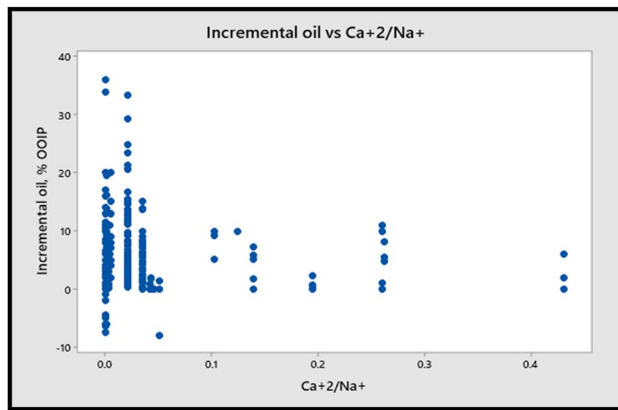


Fig. 6 Relation between $\text{Ca}^{+2}/\text{Na}^{+}$ and additional oil recovery

is an optimum pH as well. They suggested that lowering the pH of the low-salinity brine changed the electric charges at both oil/brine and rock/brine interfaces from highly negative to closer to neutral. That decreases the repulsive forces and reduces the expansion of the electric double layer caused by low-salinity water. As a result, the rock becomes more oil-wet and oil recovery is suppressed compared to low-salinity waterflooding at the original pH of the brines. Brady et al. (2015) predicted that the low-salinity effect is strongest in pH range between 5 and 6 in which salinity reduction converts the oil/kaolinite edge interaction to repulsive. Furthermore, they showed that the interaction turned into highly repulsive for pH range between 6 and 9 at all salinities which reduces the LSWF effect. They performed their experiments using oil with acid number/base number around 0.5. However, Chen et al. (2018) and Brady et al. (2015) clarified that the ranges of the pH that affect repulsive forces depend on oil acid number/base number, and salt concentrations.

Effect of clays content and clay type

Jerauld et al. (2006), Austad et al. (2010), Robertson et al. (2003), and Secombe et al. (2008) state that the clay content and clay type are essential parameters in LSWF projects. Amirian et al. (2019) showed that the clay minerals, especially kaolinite, are the controlling factors of improved recovery from LSWF. However, Soraya et al. (2009) concluded that the kaolinite is not necessary for LSWF effect. Shehata and Nasr-El-Din (2014) concluded that although expansion of double layer (EDL) due to kaolinite content might be an important factor, the presence of clay was not necessarily the primary mechanism in LSWF experiments. Bartels et al. (2017) revealed an effect of LSWF by measuring contact angle despite the absence of clay.

Figure 2b reveals the incremental oil recovery versus clay content in the tertiary stage. The highest incremental oil recovery was recorded with the plugs which have less

than 5 wt% clay content. Minor incremental oil recovery (up to 6%) was observed with the plugs which have clay content of more than 10%.

Figure 3b shows the incremental oil recovery versus clay content in secondary stage. Few plugs had a description for clay content. The highest incremental oil recovery (up to 20%) was recorded for the plugs with less than 13 wt% clay content.

Figures 2c and 3c show the relation between the kaolinite content and the additional oil recovery in tertiary and secondary stages. Similar to clay content, there is no direct relation between the kaolinite content and the additional oil recovery. Moreover, Rezaeidoust et al. (2010) and Nasralla and Nasr-El-Din (2011) did not notice additional oil recovery in plugs with 3–5% kaolinite content.

Figure 2c reveals the incremental oil recovery versus kaolinite content in the tertiary stage. The highest incremental oil recovery was recorded with the plugs which have kaolinite content of less than 2 wt%. Two free kaolinite plugs showed incremental oil recovery up to 8%. Minor incremental oil recovery (up to 3%) was observed with the plugs which have kaolinite of more than 6 wt%.

Figure 3c illustrates the incremental oil recovery versus kaolinite content in the secondary stage. Few plugs had a description for kaolinite content in the secondary stage. The achieved incremental recovery during the secondary stage is less sensitive to the kaolinite content less than 5 wt%.

The reviewed literature reported LSWF effect for core plugs containing other types of clay. The presence of reactive plagioclase, such as albite, that can contribute to increasing the pH was shown by Piñerez et al. (2016) to increase recovery. Siyambalagoda and Thyne (2011) showed additional oil recovery in the presence of calcite without any other type of clay. Cissokho et al. (2010) reported a 10% increase in recovery by injecting low-salinity brine into sandstone cores that contained illite and chlorite and were free from kaolinite.

Effect of permeability

The literature review did not show direct relation between permeability and LSWF as shown in Figs. 2d and 3d. Additional oil recovery was noticed in all ranges of permeability.

As shown in Fig. 2d, the plugs with a range of 100–1000 mD permeability showed the highest incremental oil recovery in the tertiary stage. The incremental oil recovery was less than 10% for plugs with permeability less than 5 mD. Figure 3d shows that plugs with approximately 100 mD permeability gave the highest incremental oil recovery in the secondary stage, while incremental oil recovery was less than 5% for plugs with permeability less than 10 mD.

Shaker and Skauge (2012) and Hadia et al. (2012) showed that a low-salinity flood seemed favorable when the initial

wetting conditions were not water wet. Ashraf et al. (2010) found a higher reduction in residual oil saturation under water-wet conditions.

Effect of temperature

Rezaeidoust et al. (2010) did not show any additional oil recovery for experiments conducted at temperatures below 140 °F in the tertiary stage. Nasralla et al. (2011) did not notice any additional oil recovery in experiments conducted at temperature above 212 °F in the tertiary stage.

Aghaeifar et al. (2015) observed that the LS EOR effect decreases as the reservoir temperature increases due to the decrease in the adsorption of the active organic polar components onto clay minerals. Piñerez et al. (2016) revealed that there is small induction in pH gradient, when the reservoir temperature is increased (especially when $T_{res} > 212$ °F) which decreases the effect of LSWF. However, Arumugam et al. (2019) claim a high-temperature sandstone reservoir will be a potential candidate for LSWF.

Fractional factorial design analysis

Fractional factorial design (FFD) is a commonly used method of experimental design which can be used to enhance and simplify the studies. Two-level folded Plackett–Burman design was used to estimate the high effective factors on the incremental oil recovery.

The analysis was carried out using rock, clay, formation fluid, HS, and LS properties. Some of the literature data had the complete set of all parameters, while others did not have the clay properties. As a result of that, the analysis was performed using all the dataset and repeated again using the data without clay properties. Furthermore, the analysis was performed for both secondary and tertiary stages combined and repeated for secondary and tertiary stages individually. Accordingly, six analyses were performed to identify the parameters which have the most influence on the LSWF incremental oil recovery.

The first analysis was carried out using all datasets which include clay properties data in both secondary and tertiary stages. These datasets were not large enough due to the small amount of experiments with clay description. The second analysis was carried out using all datasets without considering clay properties as a regression parameter. Figure 7 shows that the most dominant parameters in the LSWF are the minerals of the injected low-salinity water (Mg^{+2} , Na^{+} , and Ca^{+2} and Ca^{+2} of the formation water). However, Fig. 8 clarifies that in the absence of taking clay content in consideration, the high-salinity minerals are the major parameters in the LSWF.

Figures 9 and 10 show the results of the analysis for the application of the LSWF in the secondary stage with and without the clay content, respectively. The figures reveal the same results: Without considering the clay properties in the regression, the high-salinity minerals are the most effective parameters in the LSWF. In addition, the results of

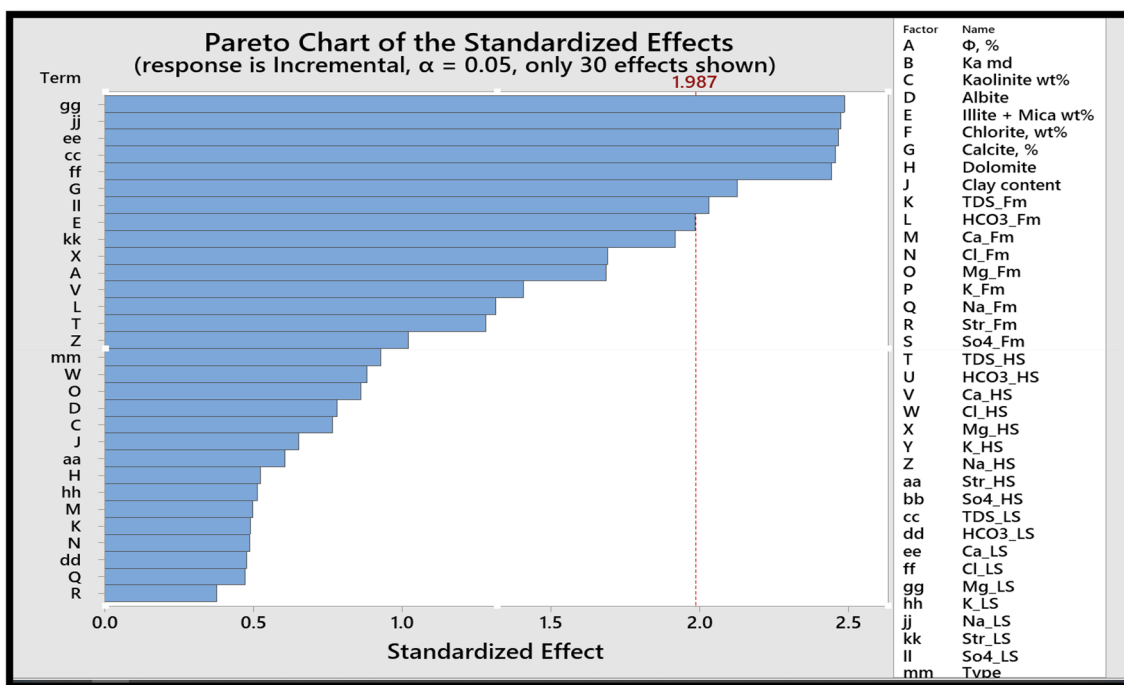


Fig. 7 Pareto chart using the complete dataset of the secondary and tertiary stages

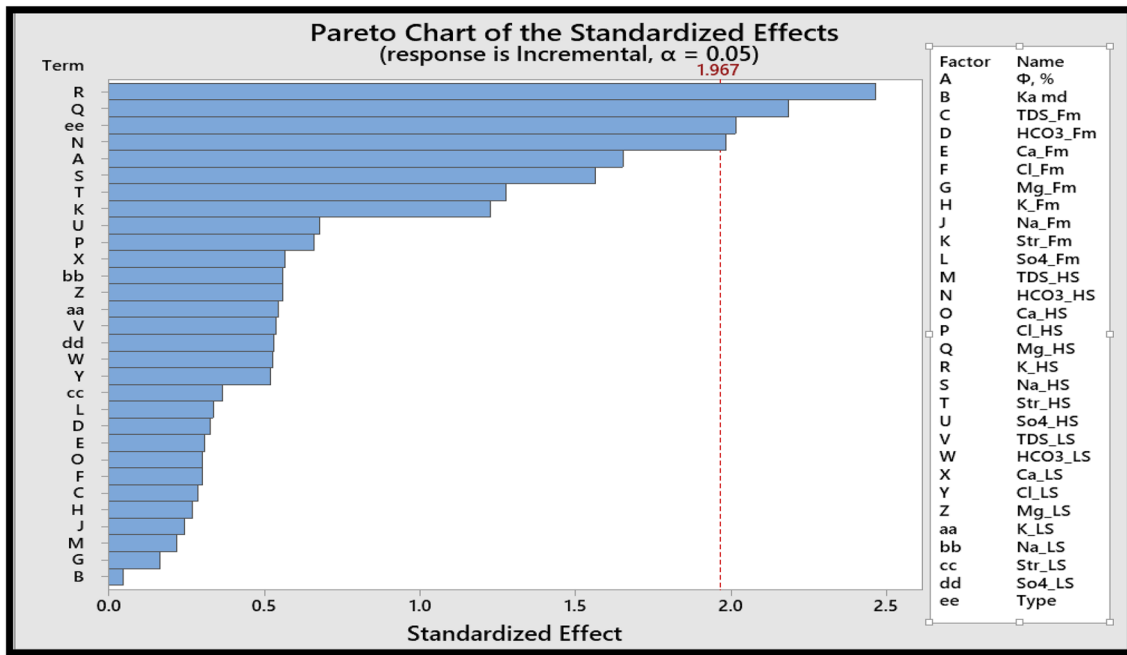


Fig. 8 Pareto chart using the datasets (without considering clay properties) of the secondary and tertiary stages

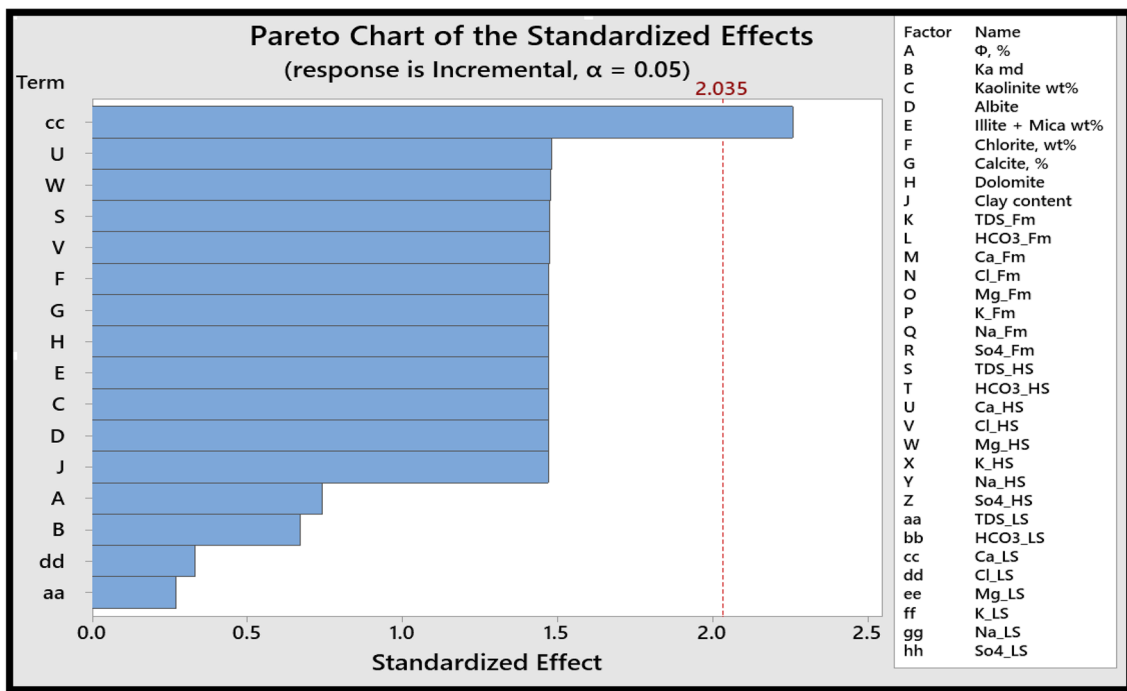


Fig. 9 Pareto chart using the complete dataset of the secondary stage

the analysis showed that the low-salinity minerals, especially Ca^{+2} , are the major parameters in the LSWF when taking clay properties in consideration.

These results match with those obtained by Lager et al. (2008a), Austad et al. (2010), Haagh et al. (2017), and others who showed that the salt content of the injected water

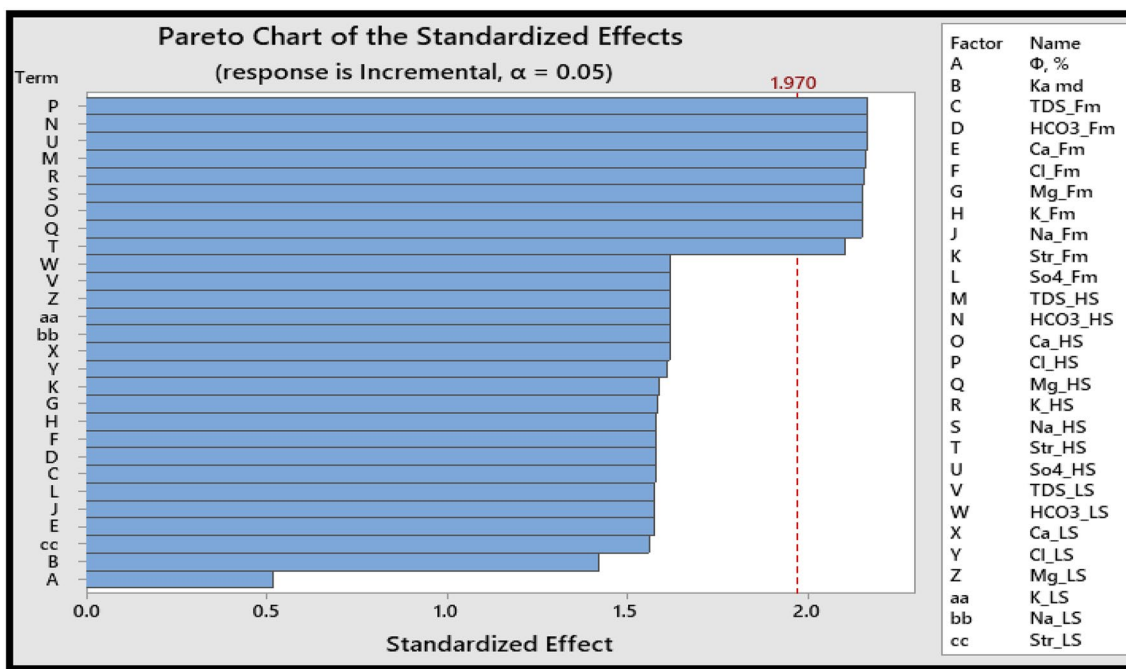


Fig. 10 Pareto chart using the datasets (without considering clay properties) of the secondary stage

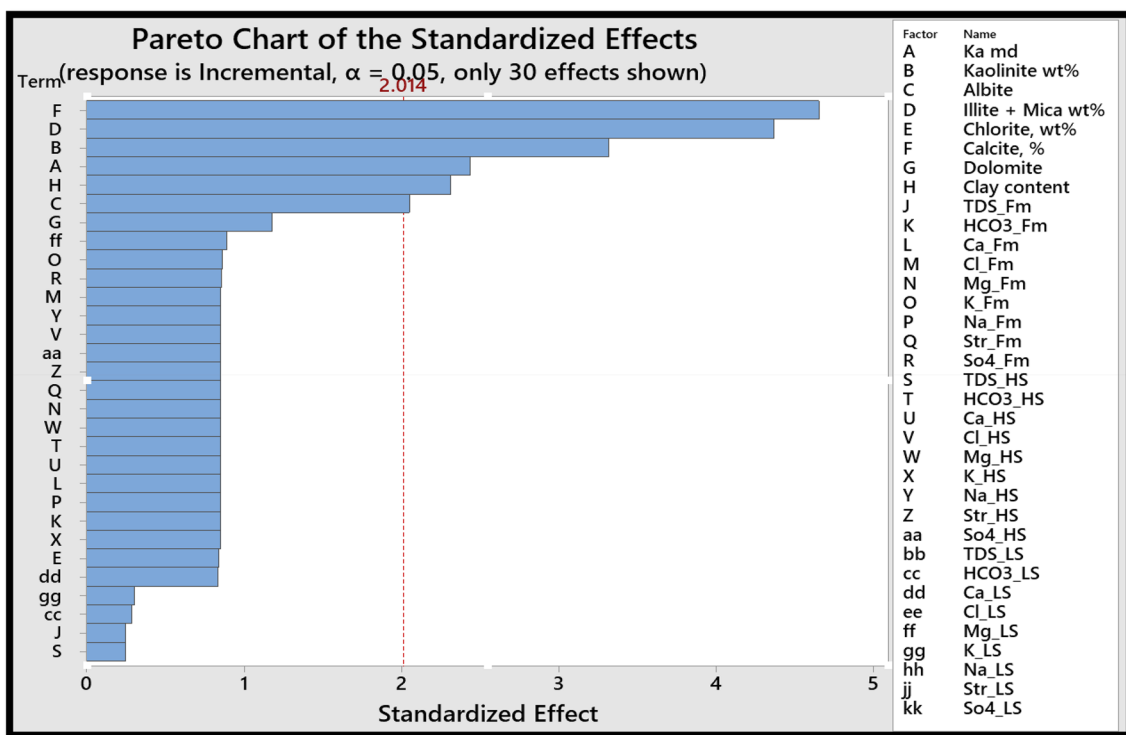


Fig. 11 Pareto chart using the complete dataset of the tertiary stage

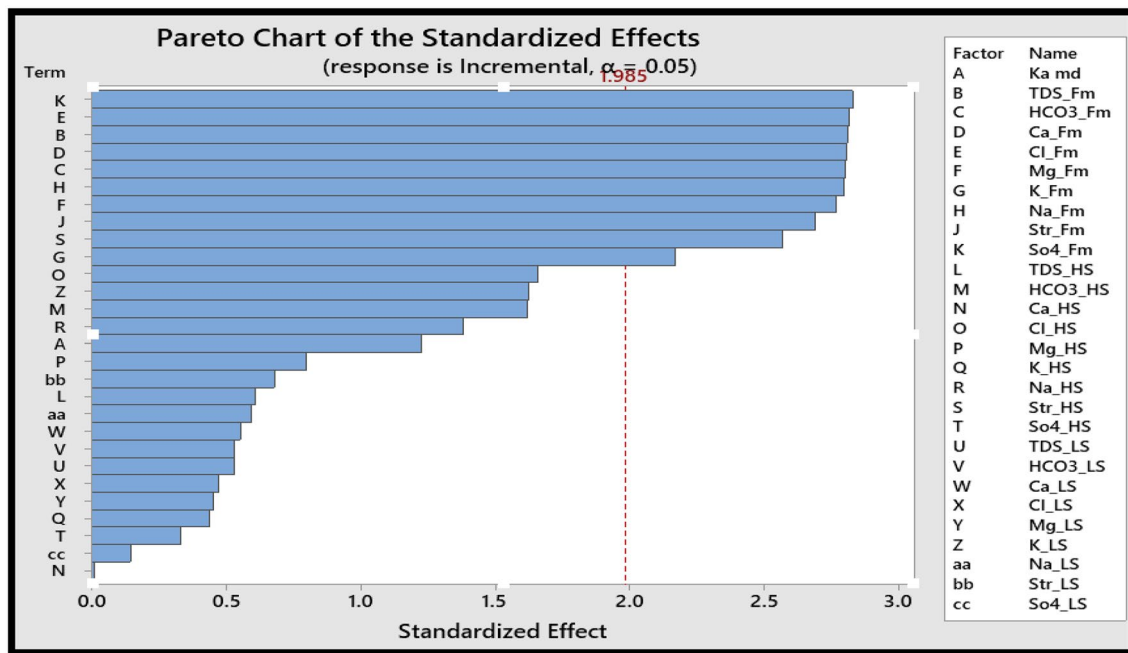


Fig. 12 Pareto chart using the datasets (without considering clay properties) of the tertiary stage

and the concentrations of the divalent ions have a strong effect on the wettability.

Furthermore, Figs. 11 and 12 present the analysis results which determine the most effective parameters when the LSWF is applied in the tertiary flooding stage. The results show that the clay content, clay minerals, and formation fluid properties are the most dominant parameters, when the LSWF is applied in the tertiary stage.

Screening criteria

Aghaeifar et al. (2015) require a balanced adsorption of organic material, Ca^{2+} and H^+ onto the clay surfaces to notice the effect of LSWF. This can be obtained if: (1) the rock contains a significant amount of active clays (illite and kaolinite), preferentially more than 10% in weight; (2) the crude oil contains polar components, acidic, and/or basic material, quantified by the acid number (AN) and base number (BN); (3) the formation water contains divalent cations, especially Ca^{2+} ; or (4) the initial reservoir pH is less than 6.5 ($\text{pH} < 6.5$).

Rotondi et al. (2014) documented the following criteria for best results when applying LSWF: (1) The injected source water should have a salinity less than 6000 ppm with optimal range between 1000 and 2000 ppm; (2) the formation rock should contain water sensitive minerals (clay) and should not be strongly water wet; (3) the formation brine should contain divalent ions; and (4) the reservoir oil should contain polar components.

However, by reviewing the literature, some elements of the screening criteria are validated and accepted, while others should be added and/or modified. The comprehensive review of the literature results allows the recognition of different screening criteria for LSWF in secondary and tertiary stages.

For the tertiary stage waterflooding, changing the salinity can give additional oil recovery. In addition, the reservoir temperature should be between 140 and 212 °F.

For the secondary stage waterflooding, there is an optimum salinity between the conventional high salinity (formation water) and the salinity of the freshwater. In addition, the optimum injected water should have the same pH of the formation water with best results when pH is around 5–6. The reservoir temperature should be above 140 °F (with no maximum limit for the temperature).

In both secondary and tertiary stages, there must be the presence of at least of one of the following: kaolinite, illite, chlorite, albite, or calcite to notice additional oil recovery. The injected water monovalent cations should be higher than the divalent cations. In addition, the permeability should be higher than 2 md.

Conclusions

In this work, a comprehensive literature review was conducted and data from the literature were analyzed to derive new findings and screening criteria for low-salinity water

injection. Based on the results of this study, the following conclusions can be made:

- There is an optimum salinity, optimum injected water composition, and optimum pH for waterflooding each reservoir rock. Careful design of water injection (when cost allows) will improve displacement efficiency and yield additional recovery.
- Clean sand reservoirs without clay content and with good permeability are expected to give less oil recovery during low-salinity waterflooding projects than high-salinity waterflooding.
- Experimental work for each specific reservoir is essential for determining the optimum salinity.
- Changing the water salinity (not LS) in the tertiary stage of EOR waterflooding gives additional recovery.
- Best results for the secondary stage of LSWF (screening criteria) will be obtained when:
 - The presence of kaolinite, albite, and/or calcite.
 - Permeability should be higher than 2 md.
 - Monovalent cations in the injected water should be higher than divalent cations.
 - Temperature should be higher than 140 °F.
- $\text{Ca}^{+2}/\text{Na}^{+}$ ratio should be less than 0.04. Some screening criteria for tertiary stage of EOR waterflooding are:
 - The presence of kaolinite, albite, and/or calcite.
 - Permeability should be more than 2 md.
 - Monovalent cations in the injected water should be higher than divalent cations.
 - Temperature should be higher than 140 °F and less than 212 °F.

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