



Case Study: The impact of Low Salinity Waterflooding on Sandstone Reservoirs at Egypt's Western Desert



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SURFACE chemistry has a great effect in enhancing oil recovery (EOR). For oil-wet sandstone reservoirs, low salinity waterflooding (LSWF) is effective as it can alter rock wettability and reduce the oil/water interfacial tension. LSWF application is related to the rock's clay content and type. Clay hydrocarbon bonding can be formed through many mechanisms such as van der Waals forces and ionic bridge. LSWF effect is to weaken these bonds through two main mechanisms, Double Layer Expansion (DLE) and Multicomponent Ionic Exchange (MIE). This research figures out the impact of LSWF application through a comparison between two fields (S & D), in Egypt's Western Desert, which have depleted strongly oil-wet reservoirs with similar rock & fluid Properties. Field (S) is flooded by low salinity water (LSW), while field (D) is flooded by high salinity water (HSW). Fortunately, the LSWF application was with no extra desalination cost as the water source for field (S) flooding is a LSW aquifer zone, which has a salinity +/- 5000 ppm as total dissolved solids (TDS). Water Susceptibility for Field (S) rock showed good compatibility between the injected LSW, formation water and rock minerals. XRD and SEM for field (S) indicate calcareous cementation with detrital clays content around 5% which is mainly kaolinite. This composition helps to activate the LSWF effect. For field (S), the estimated ultimate recovery (EUR) is 46%, while EUR for field (D) is 39%. One of the main causes of this increase in field (S) is the successful LSWF application.

Keywords: Low salinity waterflooding, Wettability, Oil-wet, concentration, Recovery, water cut, EOR.

Introduction

Waterflooding is an important application that can help in increasing the oil recovery factor (RF), as it maintains the reservoir pressure and sweeps more oil from the reservoir to the producer wells. For an oil-wet reservoir, LSWF application shows better effect than HSW due to its effect to alter the rock wettability and reduce the oil/water interfacial tension. The key advantage of LSWF over other EOR techniques includes the simple operational design, low cost, avoidance of toxic chemical usage, and reducing the potential for sulphate scaling and reservoir souring. Therefore,

the selection of LSWF suitable conditions is necessary to maximize the oil recovery, through lab experiment and simulation studies. Understanding the mechanism behind LSWF helps in determining the optimum salinity and water composition for waterflooding design. Surface chemistry helps in understanding LSWF mechanism. For an oil-wet sandstone reservoir, Clay hydrocarbon bonding can be formed through many mechanisms, such as van der Waals forces and ionic bridge, as showed in Figure 1 [1]. LSWF role is to weaken these bonds through two main mechanisms, Double Layer Expansion (DLE) and Multicomponent Ionic Exchange (MIE).

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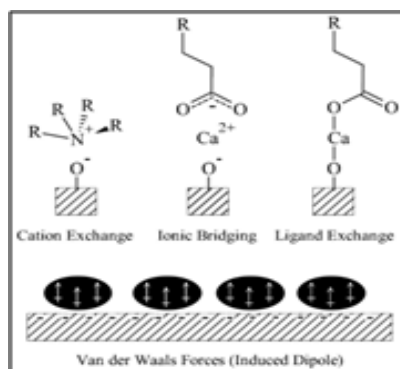


Fig. 1. Clay hydrocarbon bonding main mechanisms [1].

LSWF mechanisms

For DLE (2009 Ligthelm *et. al*) [2], A negatively charged surface in an electrolyte such as brine will form an interface known as the electrical double layer (DL) whereby similarly charged particles will be repelled from the surface and oppositely charged particles attracted to the surface, as showed in figure 2. This DL effect is to neutralize the surface charge. In a petroleum system, both the negatively charged oil/water interface and the clay surfaces will have associated DL. In a brine of high ionic strength, the DL thickness will be small. This allows the oil and the clay to get physically close enough for interaction with the active oil components, allows oil adsorption and a change to an oil-wet state. Figure 3 shows that During LSWF, the DL expand and overlap. At sufficiently low salinity, the repulsion between the similarly charged oil/water interface and clay surface will overcome the binding force, this causes oil desorption and a change to a more water-wet surface [4].

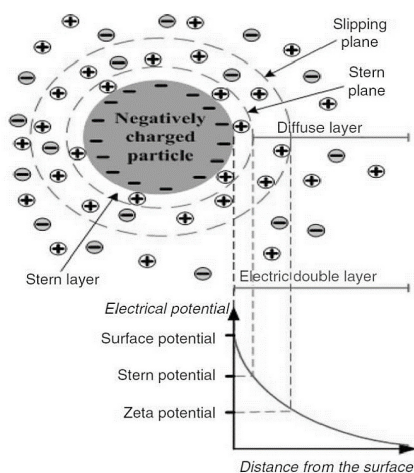


Fig. 2. A schematic of the electric double layer. [3].

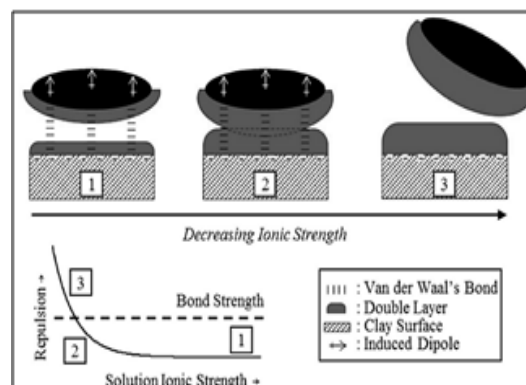


Fig. 3. Decreasing ionic strength due to DLE [4].

For MIE (2008a Lager *et. al*), it suggests that during the flood, exchange will take place at the clay surface, removing directly adsorbed organic compounds and organometallic complexes formed with multivalent ions. This leads to the desorption of organic matter and promotes water wetness. [1]

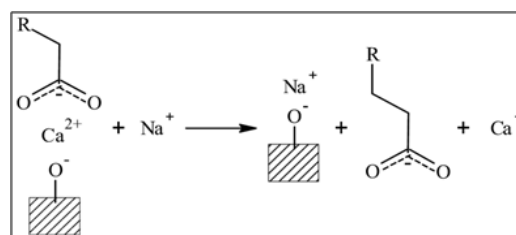


Fig.4. Multicomponent ionic exchange [4].

Sometimes, LSWF has minor effects that can share in recovery increase such as Fine migration and pH increase. For Fine Migration (1999 Tang, G.Q. & Morrow, N.R.) [5], Partial formation damage occurs, mobilizing fine particles. The particles preferentially settled in high permeability streaks in the rock, improving sweep efficiency. This had the additional benefit of releasing residual oil attached to the particles [4]. For pH effect (2005 McGuire *et. al.*) [6], pH increases in the effluent because of increased dissolution of basic minerals (CaCO₃). These minerals react with acidic components in the hydrocarbon, generating in-situ surfactant and improving oil recovery through a reduction in interfacial tension and a change to a more favourable wettability state [4]. Noting that, an oil with a high acid number (>0.1-0.2 mgKOH/g) is required to generate sufficient surfactant (Ehrlich and Wygal 1977) [7]. For a crude with a very low acid number, no change in effluent pH is determined [4].

Nona fluid pretreatment prior to LSWF can reduce the bad effects of fine migration near the wellbore. Its size is smaller than grain pore size, as it improves the retention force that keeps fines in its place and prevents damage in near the wellbore. Far from the wellbore, fine migration adjusts the water to go for less permeable zones and improving sweep efficiency [8].

Osmosis as Mechanism for LSWF

DLE theory is valid for sandstone reservoirs, but for carbonate rock DLE may contribute to a more oil-wet, as the carbonate surface has a positive net charge. Osmosis is more valid as a LSWF mechanism for both rock types. Osmosis effect is due to the salinity difference between the injected water and connate water. For oil-wet rock, osmosis can drive the injected water, not ions, to flow through oil film “which acts as a semipermeable membrane” to the connate water. This can cause rupture of oil film and wettability alteration to water-wet. For lab experiments, usage of spontaneous imbibition tests to confirm wettability alteration should be reinvestigated. This is because observed production increase could be caused by osmosis rather than wettability change [9].

Clay effect

Clay can be used in many applications due to its cation exchange capacity. For example, it can be used as a bleaching earth in the motor-oil refinery [10]. Clay is existing in most of sandstone reservoir rock in different percentages. When become in contact with fresh water, clay swelling can occur due to absorption of water ions. Clay swelling can cause a great reduction in rock permeability. This depends on the clay structure, which related to the clay cation exchange capacity (CEC). Kaolinite structure is 1:1 bond tetrahedral-octahedral (TO-TO), has the lowest CEC between clay types, which promotes LSWF application, with minimum clay swelling.

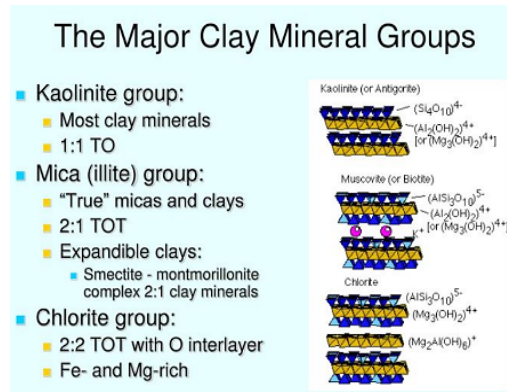


Fig. 5. The major clay mineral groups [11].

TABLE 1. Properties of actual clay minerals (International Drilling Fluids (IDF) 1982) [12].

Property	Kaolinite	Illite/Mica	Montmorillonite	Chlorite
Layers	1:1	2:1	2:1	2:1:1
Particle size (micron)	5-0.5	large sheets to 0.5	2-0.1	5-0.1
Cation exchange cap. (meq/100g)	3-15	10-40	80-150	10-40
Surface area BET-N ₂ (m ² /g)	15-25	50-110	30-80	140

For clay hydrocarbon bonding via cation exchange, when applying LSWF reactions between adsorbed basic and acidic materials

with injected water helps in oil release from clay surface as illustrated in figure 6.

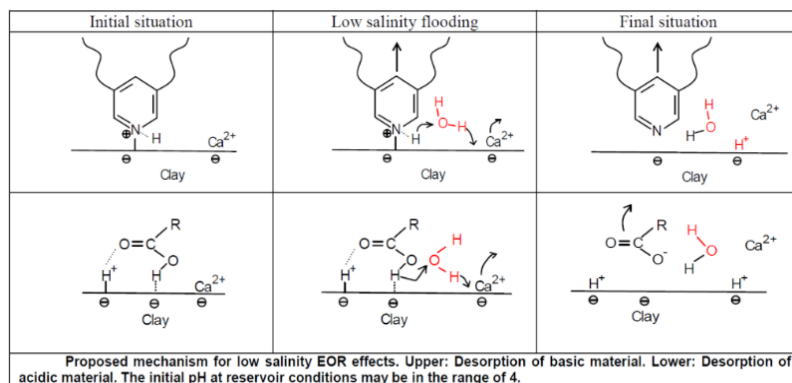


Fig. 6. LSWF mechanism for basic and acidic material [12].

Many factors are affecting LSWF performance such as Rock-type, Clay content, Oil Polar components, Formation water, the salinity and composition of the injection water, and Temperature as illustrated in figure 7. The usual salinity for LSWF effects is in the range of 1000

-2000 ppm (Austad et al. 2010) [12]; however, water salinity ~5000 ppm (McGuire et al. 2005) [6] showing good effects are also observed. The upper limit of optimum salinity differs depending on the reservoir type and can be best determined through lab experiments and pilot wells.

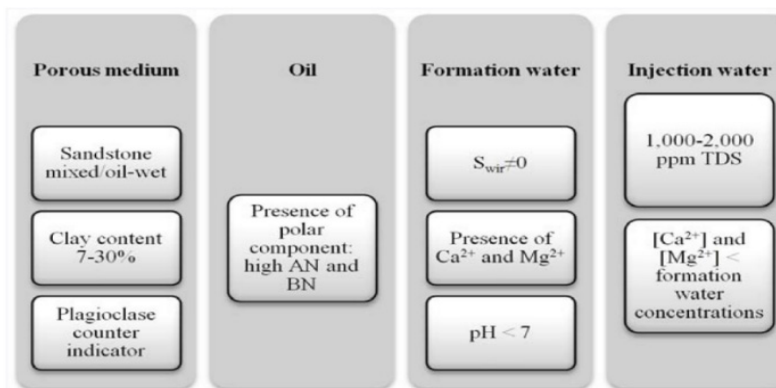


Fig. 7. LSWF requirements for sandstone [13].

LSWF field application

For depleted oil reservoirs, waterflooding application as a secondary recovery mechanism is important to increase the oil recovery factor because it maintains the reservoir pressure and sweeps more oil from the injector wells to the producer wells. For depleted oil-wet reservoirs, LSWF can be applied as a tertiary recovery mechanism to alter the wettability from oil wet to water wet. The optimum salinity limit can be investigated by lab experiments and neuro-simulation studies [14] to minimize the desalination cost for the injected water. However, in case of LSW availability with no desalination need, as in rivers or low salinity underground aquifer zones, LSWF can be applied at the start

of flooding as a secondary recovery mechanism.

Case study

A two depleted strongly oil-wet reservoir are allocated in Egypt's Western Desert, in fields (S & D). Special core analysis (SCAL) for different wells in these fields indicated a strongly oil-wet sandstone rock. Their primary recovery factor did not reach 10%. Their low drive energy made an effective waterflooding essential to achieve reasonable recoveries. The two fields have similar rock & fluid Properties as listed in table 2. Field (S) is flooded by low salinity water (LSW), while field (D) is flooded by high salinity water (HSW).

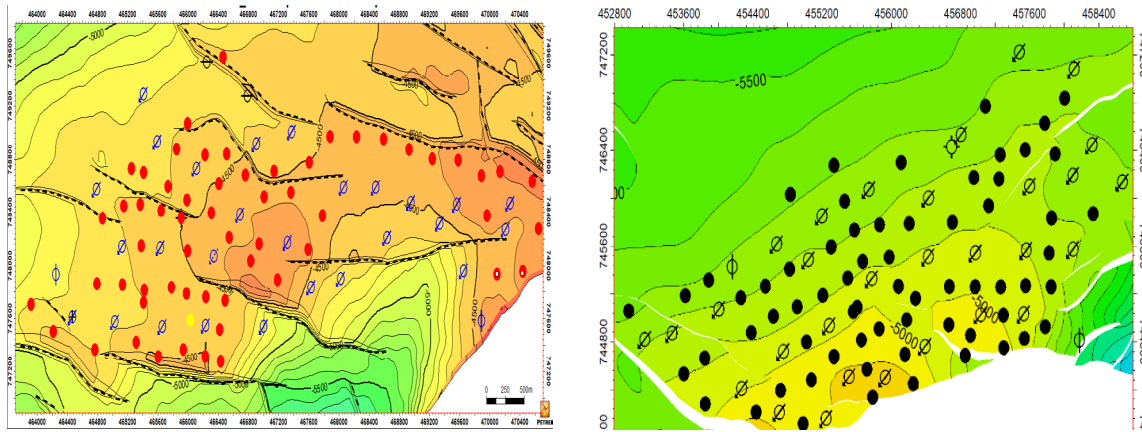


Fig. 8. (A) Field S structure map (producers & injectors).

(B) Field D structure map (producers & injectors).

TABLE 2. Average Rock & Fluid Properties.

	Field name	Field S	Field D
FIELD DATA	waterflooding	LSW	HSW
	TDS	5000 ppm	20,000 ppm
	formation water salinity	25000 ppm	24000 ppm
	wettability	strongly oil-wet	strongly oil-wet
PVT DATA	Pr, initial (psi)	2100	2500
	API @ 60' F	24°	25
	Pb (psi)	64	135
	Rs (SCF/STB)	37	8.4
	Bo,i (BBL/STB)	1.05	1.045
	μo cp @ S.C.	5.1	7.3
	Bw BBL/STB	1.01	1.092
	μw	0.5	0.5
SCAL DATA	Tf	165 F	160 ° F
	Kair mD	101	79
	Sw,c	10%	11%
	Sor	37%	34
	MOBILITY	19	21
	Phie φ	18%	21%
	V-Lime	17%	15%

Fortunately, the water source for flooding in field S is LSW aquifer zone. LSWF was started with TDS of less than 5000 ppm, while the formation water salinity is +/- 25,000 ppm TDS.

After two years the salinity of the water source increased to be +/- 6300 ppm as illustrated in table 3.

TABLE 3. Water analysis for two low Salinity injectors after two years of the flooding start.

Dissolved Solids			Salts		
Ions			Salts		
Sod. & Pot.	1038	PPM	Barium Sulphate	0	PPM
Calcium	76	PPM	Calcium Carbonate	190	PPM
Magnesium	12	PPM	Strontium Sulphate	0	PPM
Barium	0.00	PPM	Calcium Sulphate	0	PPM
Strontium	0.00	PPM	Barium Chloride	0	PPM
Chlorides	2244	PPM	Strontium Chloride	0	PPM
Sulphate	465	PPM	Calcium Chloride	0	PPM
Bicarbonates	451.0	PPM	Magnesium Sulphate	59	PPM
carbonates	0	PPM	Magnesium Chloride	0	PPM
Hydroxide	0	PPM	Sodium Sulphate	0	PPM
T.D.S.	6500	PPM	Sod. & Pot.Chlorides	4037	PPM
Physical properties					
Sp.Gr.	1.0048		Total alkalinity	370	PPM
pH	7.07		Total Hardness	239	PPM
Salinity as NaCl	3699	PPM	Temporary Hardness	239	PPM
Iron	0.52	PPM	Permanent Hardness	0	PPM

Dissolved Solids			Salts		
Ions			Salts		
Sod. & Pot.	1345	PPM	Barium Sulphate	0	PPM
Calcium	80	PPM	Calcium Carbonate	200	PPM
Magnesium	22	PPM	Strontium Sulphate	0	PPM
Barium	0.00	PPM	Calcium Sulphate	0	PPM
Strontium	0.00	PPM	Barium Chloride	0	PPM
Chlorides	2300	PPM	Strontium Chloride	0	PPM
Sulphate	250	PPM	Calcium Chloride	0	PPM
Bicarbonates	450.0	PPM	Magnesium Sulphate	109	PPM
carbonates	0	PPM	Magnesium Chloride	0	PPM
Hydroxide	0	PPM	Sodium Sulphate	0	PPM
T.D.S.	6000	PPM	Sod. & Pot.Chlorides	4138	PPM
Physical properties					
Sp.Gr.	1.0050		Total alkalinity	369	PPM
pH	6.80		Total Hardness	290	PPM
Salinity as NaCl	3791	PPM	Temporary Hardness	290	PPM
Iron	3.00	PPM	Permanent Hardness	0	PPM

Materials and Methods

Cores had been taken from an oil-wet reservoir. Plug Drilling, Sample Cleaning, wettability measurement, and Water Susceptibility have been made as follows:

Plug Drilling

Core plugs of one and half-inch diameter were drilled using a diamond core drill with simulated formation water as a bit coolant and lubricant. The one and half-inch diameter cylindrical core plugs obtained were trimmed with a diamond core saw to form a uniform right cylinder. The samples were numbered for identification.

Sample Cleaning

Hydrocarbons were extracted from the plug samples in a cool solvent reflux soxhlet using toluene. Any salt present was leached from the samples using methyl alcohol in a solvent reflux soxhlet extractor. The samples were considered to be clean of salts when the methanol in direct contact with the plug was free from precipitate when tested with a 10% silver nitrate solution, and clean of residual hydrocarbon when the core plugs did not show any fluorescence when viewed under ultraviolet light. The samples were dried in

a regular oven at 85°C.

Wettability measurement (Amott test)

The clean and dry samples scheduled for this analysis were evacuated and pressure saturated with the simulated formation water. To begin the Wettability test, each of the samples was placed in a hydraulic-type core holder and flushed to immobile water saturation using mineral oil of 9 cp viscosity. Effective permeabilities to oil are then measured. Following this, the samples are submerged under the simulated brine and the volume of brine imbibed noted. The samples are next flooded with the brine and the volume of displaced oil recorded. Specific permeabilities at residual oil saturation are measured. The wettability index to water is calculated for each sample. The samples are then placed under oil and the volume of oil imbibed under static conditions is determined. Once equilibrium has been reached, the samples are flooded with oil. Dynamic volumes of oil imbibed are recorded and the wettability index to oil is calculated.

Sample Saturation

The selected samples were initially loaded into a saturation cell and evacuated for a minimum of

16 hours. The cell was then filled with simulated formation brine containing approximately 18,000 ppm total dissolved solids as shown in table 4. The pressure was increased to 2000 psi and maintained for a minimum of two hours. The brine-saturated samples were removed from the cell and weighed. The gravimetric saturated pore volume was calculated and compared to the gas expansion pore volume to verify complete saturation.

Water Susceptibility (permeability reduction)

SEM analysis is performed on small pieces of rock trimmed off core plugs before any testing is started on the core plugs. This should enable the study of the mineral morphology and pore geometry, particularly involving clay minerals, before any alteration or damage to them. Core plugs are saturated with synthetic formation brine and then permeability to that brine is determined at a low flow rate. The flow rate is increased and permeability is recorded against increasing flow rate. If permeability reduction is observed above a certain flow rate (critical velocity), the

sample is removed for further SEM examination. Another core plug is saturated and permeability to synthetic formation brine is determined at a low flow rate. This is followed by filtered injection brine containing approximately 2650 ppm total dissolved solids as shown in table 5. The flow of filtered injection brine is continued at the same low flow rate until permeability reduction occurs or for at least thirty pore volumes. If no permeability reduction is observed, then the flow rate is incrementally increased up to the same critical velocity as previously determined. If permeability reduction is observed then after unloading the core plugs, further SEM examination on a piece of the tested plug is performed. Testing is repeated on several core plugs covering the range of rock type and permeability/porosity distribution that occur in the injection zone. A comparison is made between the SEM results from the pre-test sample and sample after brine throughput to investigate clay or other mineral damage that may have caused the permeability reduction. Figure 9 shows the flow chart for research methodology.

TABLE 4. Formation water composition.

Salts	Concentration ppm
Sodium Bicarbonate	873
Sodium Sulphate	192
Magnesium Chloride	196
Calcium Chloride	734
Potassium Chloride	3375
Barium Chloride	1.3
Sodium Chlorides	12860
TOTAL	18231

TABLE 5. Injected water composition.

Salts	Concentration ppm
Sodium Bicarbonate	658
Sodium Sulphate	887
Magnesium Chloride	58
Calcium Chloride	256
Potassium Chloride	312
Barium Chloride	**
Sodium Chlorides	479
TOTAL	2650

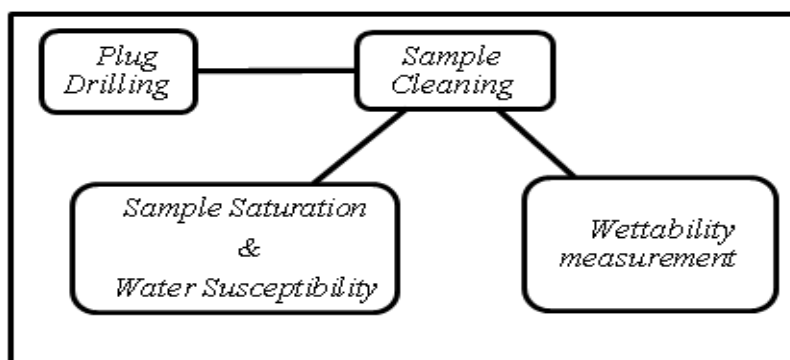


Fig. 9. a flowchart for the research methodology.

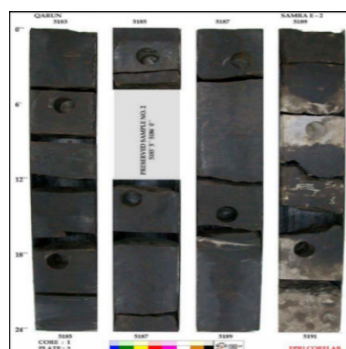
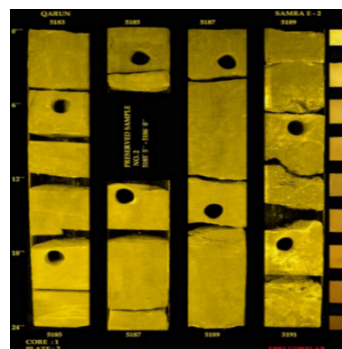


Fig. 10. Core plugs photo (a) White light.



(b) Ultraviolet light.

Results and Discussion

Wettability measurement (Amott test)

Wettability indices for different cores are listed in table 6, showing that the average of the

oil wet index for these cores is ± 0.7 , while the average of the water-wet index is ± 0.03 . This means that the reservoir rock is a strongly oil-wet

TABLE 6. Wettability indices for different cores.

Sample No.	Depth (Ft)	Water Wet Index	Oil-wet Index	Final Results
Well: S-E2				
SE2 - 5	5185' 8"	0.00	0.96	Strongly oil-wet
SE2 - 12	5199' 3"	0.00	0.91	Strongly oil-wet
SE2 - 14	5205' 7"	0.00	0.98	Strongly oil-wet
Well: S-30				
S30 - 34	5225' 9"	0.00	1	Strongly oil-wet
S30 - 12	5231' 2"	0.06	0.16	Moderately oil-wet
S30 - 15	5238' 10"	0.07	0.58	Oil-wet
Well: S-8x				
S8x - 1	5365' 3"	0.00	0.90	Strongly oil-wet
S8x - 6	5376' 6"	0.00	0.56	Oil-wet
S8x - 9	5391' 1"	0.18	0.16	Mixed Wettability

Water Susceptibility (permeability reduction) results

Many factors can cause a permeability reduction such as fine migration in the pore throats, clay swelling, and chemical precipitation. Water Susceptibility (permeability reduction) for different cores from field S showed that most of the flooded cores have a minor permeability reduction in the normal injection direction. This means a good computability between the injected LSW and the formation water. For samples which showed a permeability reduction in the normal direction, a flooding in the reverse direction with high injection rate was applied to determine the permeability reduction cause. For the reverse injection direction, the permeability restored to the original values for some cores

because the migrated fine which blocked the pore throats, carried with the flooding. This means that the permeability reduction was due to fine migration rather than clay swelling or chemical precipitation. This explanation is supporting the researches which suggest that the fine migration is an effect rather than a mechanism for LSWF. For cores which showed more permeability reduction in the reverse direction, it may be due to chemical precipitation.

The water susceptibility results show minor permeability reduction, which promotes LSWF application in the field scale. Clay swelling didn't largely affect the permeability because the rock clay content for field S cores is mainly kaolinite

with low cation exchange capacity and low swelling tendency. So, for field S water susceptibility showed good compatibility between injected water, formation water, and rock minerals. The results of water susceptibility in normal and reverse direction are listed below:

Core 1: SE-02 #6 strongly oil-wet (sandstone reservoir)

Sample ID: SE2-6, Depth: 5185' 8", Air Permeability: 430 md, Pore Volume: 15.68 cc, Formation water liquid permeability (K_L): 88 md

* Permeability in reverse direction of flow with the same flow rate in the normal direction.

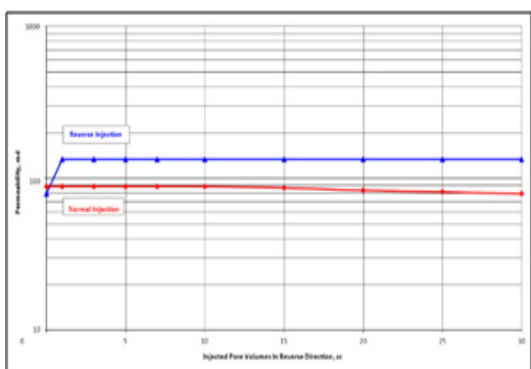


Fig. 11 Permeability versus normal and reverse injected pore volume sample #SE2-6.

Core 2: SE-02 #9 strongly oil-wet (sandstone reservoir)

Sample ID: SE2-9, Depth: 5199' 1", Air Permeability: 567 md, Pore Volume: 14.57 cc,

Formation water liquid permeability (K_L): 346 md

* Permeability in reverse direction of flow with the same flow rate in the normal direction.

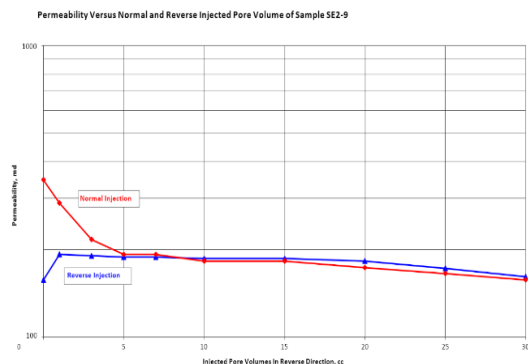


Fig. 12. Permeability versus normal and reverse injected pore volume sample #SE2-9.

Core 3: SE-02 #13 strongly oil-wet (sandstone reservoir)

Sample ID: SE2-13, Depth: 5205' 7", Air Permeability: 155 md, Pore Volume: 14.60 cc

Formation water liquid permeability (K_L): 114 md

*No flow in reverse direction because of no change in permeability value.

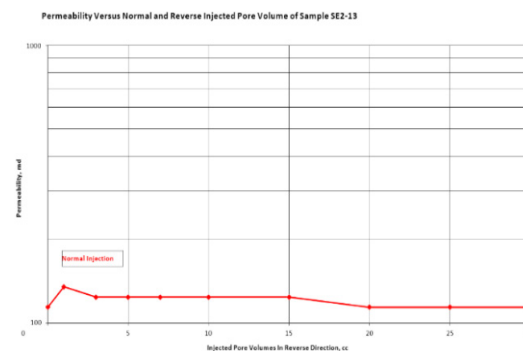


Fig.13. Permeability Versus Normal & Reverse Injected Pore Volume Sample #SE2-13.

Core 4: S-30 #11 moderately oil-wet (sandstone reservoir)

Sample ID: S30-11, Depth: 5231' 2", Air Permeability: 518 md, Pore Volume: 11.39 cc

Formation water liquid permeability (K_L): 283 md

* Permeability in reverse direction of flow with the same flow rate in the normal direction.

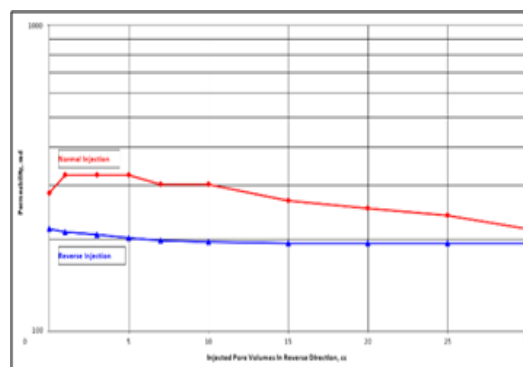


Fig. 14. Permeability Versus Normal & Reverse Injected Pore Volume Sample #S30-11.

Core 5: S-30 #16 oil-wet (sandstone reservoir)

Sample ID: S30-16, Depth: 5238' 10", Air Permeability: 3.26 md, Pore Volume: 7.19 cc

Formation water liquid permeability (K_L): 2.26 md

* Permeability in reverse direction of flow with the same flow rate in the normal direction from pore volume 0 to 10.

** Permeability in reverse direction of flow with a high flow rate from pore volume 10 to 30.

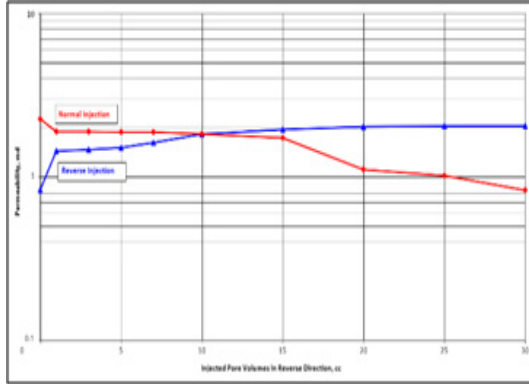


Fig. 15. Permeability Versus Normal & Reverse Injected Pore Volume Sample #S30-16.

Core 6: S-30 #51 strongly oil-wet (sandstone reservoir)

Sample ID: S30-51 Depth: 5242' 10" Air Permeability: 64 md, Pore Volume: 4.29 cc

Formation water liquid permeability (K_L): 46 md

* Permeability in reverse direction of flow with the same flow rate in the normal direction from pore volume 0 to 3.

** Permeability in reverse direction of flow with a high flow rate from pore volume 3 to 30.

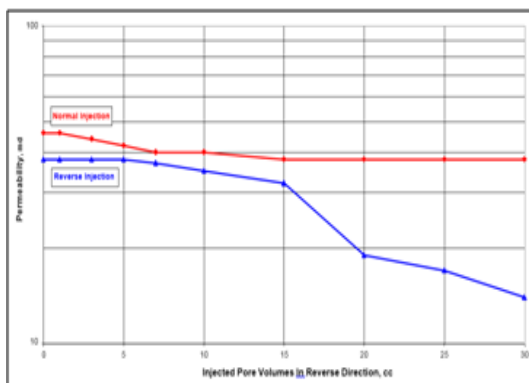


Fig. 16. Permeability Versus Normal & Reverse Injected Pore Volume Sample #S30-51.

Core 7: S-08X #2 strongly oil-wet (sandstone

reservoir)

Sample ID: S8x-2 Depth: 5365' 3" Air Permeability: 718 md, Pore Volume: 12.61 cc

Formation water liquid permeability (K_L): 650 md

** Permeability in reverse direction of flow with a high flow rate from pore volume.

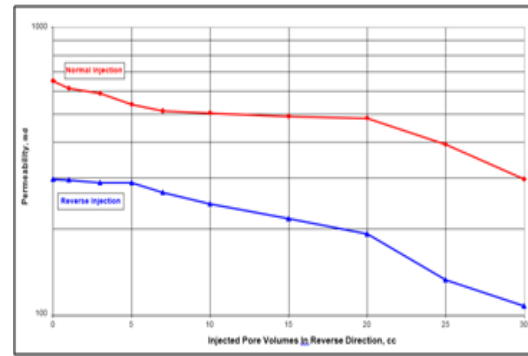


Fig. 17. Permeability Versus Normal & Reverse Injected Pore Volume Sample #S08-2.

Core 8: S-08X #5 oil-wet (sandstone reservoir)

Sample ID: S8x-5, Depth: 5376' 6", Air Permeability: 257 md, Pore Volume: 13.55 cc

Formation water liquid permeability (K_L): 160 md

*No flow in reverse direction because of no change in permeability value.

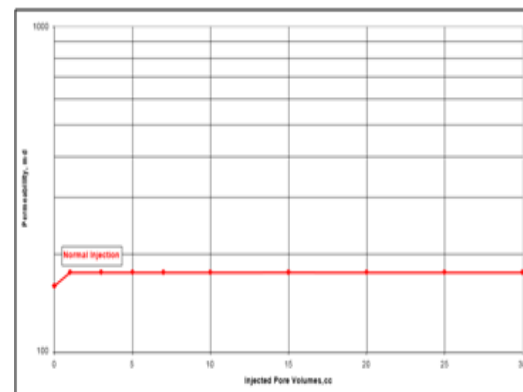


Fig. 18. Permeability Versus Normal & Reverse Injected Pore Volume Sample #S08-5.

Core 9: S-08X #11 mixed wettability (sandstone reservoir)

Sample ID: S8x-11 Depth: 5391' 3" Air Permeability: 8md Pore Volume: 11.69 cc

Formation water liquid permeability (K_L):
6.15 md

* Permeability in reverse direction of flow with the same flow rate in the normal direction from pore volume 0 to 5.

** Permeability in reverse direction of flow with a high flow rate from pore volume 5 to 30.

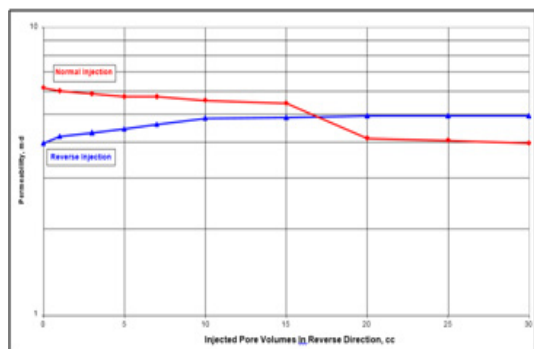


Fig.19. Permeability Versus Normal & Reverse Injected Pore Volume Sample #S08-11.

Rock Composition

XRD, Thin Section and SEM indicate detrital clays content around 5%. Kaolinite is the common clay type with subordinate quantities of very poorly to poorly crystallized illite. Plagio-Feldspar percentage is around 2%. The rock is slightly cemented with calcareous and argillaceous material, with a Volume of lime 16%. This high V-lime percentage promoted the oil-wet tendency and clay hydrocarbon bonding via ionic bridging.

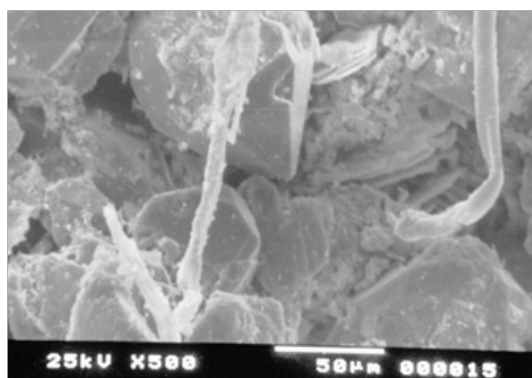
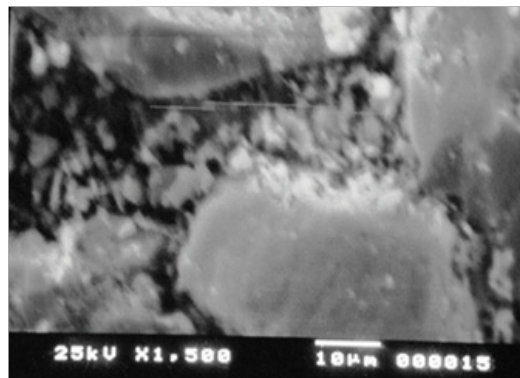


Fig.20. SEM. Photomicrograph (a) shows illite bridge and kaolinite affecting the intergranular pores, lowering the permeability. 500X.



(b) shows connected intergranular pores, filled with fine detrital clays. 500X.

Oil Composition

The whole oil gas chromatogram of oil samples is typical of biodegraded oils. Most n-alkanes are either missing or their concentration is significantly reduced. A hump of unresolved complex material in the range of nC11 to nC32 also characterizes the gas chromatogram as illustrated in figure 21. The depletion in the n-alkanes content is believed to affect most of the whole oil and C4-7 GC ratios, which should be considered with caution for the oil. The Isoprenoids (iP9 to 18, Pristane and Phytane) show a much higher concentration relative to n-alkanes.

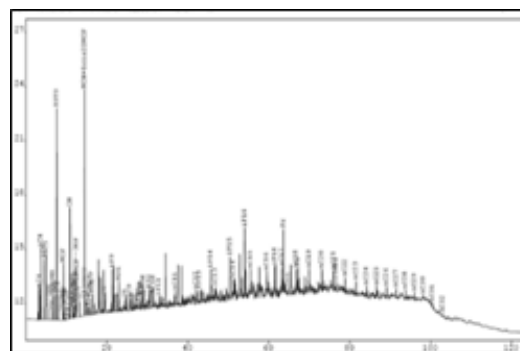


Fig. 21. gas chromatogram of oil sample.

Field results

Field S reservoir rock is a calcareous cement. This means occurrence of Calcium ions which helps in clay hydrocarbon bonding via ionic bridging. When LSWF was applied in field S, a multicomponent ionic exchange was happened between the monovalent ions in injected water and the divalent ions in formation water. This reaction altered wettability to a more water wet. Moreover, the salinity difference between the

injected water (5000 ppm) and the formation water (25000 ppm) helped in the expansion of the DL formed between the clay and the reservoir oil. Also, this salinity difference promotes osmosis to rupture the oil film around the connate water. Meanwhile, field D is flooded with regular injection water.

For field S, the original oil in place (OOIP) for the oil-wet reservoir is about 24.45 MMBBL. The estimated ultimate recovery (EUR) is about 46%. As illustrated in table 7, a comparison between the EUR in field S & D, which have similar rock & fluid properties for an oil-wet reservoir, showed an increase of 7% in field

S. There are numerous factors affecting the recovery factor and the ultimate recovery factor. Part of these factors are reservoir driven and other factors are operations driven e.g. injection rate, surface pumping, water quality (free contamination), Well Scheduling ... etc. One of the main causes of this increase is due to LSWF application, as the other field is flooded by a high salinity waterflooding. Regarding other LSWF application in Egypt fields, there is only a single field experienced LSWF in the Gulf of Suez (El-Morgan field) which belongs to GUPCO, but its results aren't published yet.

TABLE 7. A comparison between low salinity and high salinity water (Field S & D).

	Field name	Field S	Field D
	Waterflooding	LSW	HSW
	TDS	5000 ppm	20,000 ppm
	formation water salinity	25000 ppm	24000 ppm
FIELD DATA	Wettability	strongly oil-wet	strongly oil-wet
	Producers	59	65
	Injectors	29	34
	OOIP (MMSTB)	24.45	34.33
	Estimated Ultimate RF	46%	39%

Conclusion

The main mechanisms behind LSWF are DLE & MIE. Osmosis also helps in wettability alteration. Fine migration and pH increase are effects, rather than, mechanisms for LSWF. Wettability measurements for sandstone reservoirs at Egypt's Western Desert, especially those with calcareous cement, are important to investigate the oil-wet reservoirs. For the oil-wet sandstone reservoirs, LSWF application should be economically studied. LSWF can be applied with no extra cost as a secondary recovery mechanism upon the start of waterflooding project if LSW source is available such as LSW strong aquifer which may be shallow or deep zones, as in field S. If the injected water need desalination, then LSWF can be applied as a successful EOR technique after performing the proper studies to determine the optimum salinity limit, minimize the water desalination cost, and maximize the oil recovery. These studies should made via lab experiments, simulation studies and pilot wells application depending on rock and formation

water composition.

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دراسة حالة: تأثير حقن المياه منخفضة الأملاح على خزانات الحجر الرملي بصحراء مصر الغربية

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للكيمياء السطحية تأثير كبير في تعزيز استخلاص الزيت. بالنسبة لخزانات الحجر الرملي المبلل بالزيت ، فإن حقن المياه المنخفضة الملوحة فعال لأنه يمكن أن يغير قابلية الصخر للتبلل ويقال من التوتر بين الزيت / الماء .

يرتبط حقن المياه المنخفضة الملوحة بمحتوى ونوع الطين بالصخر. يمكن تشكيل الترابط الهيدروكربوني الطيني من خلال العديد من الآليات مثل تأثير قوى فان در فال والجسر الأيوني. يتمثل تأثير المياه المنخفضة الملوحة في إضعاف هذه الروابط من خلال آليتين رئيسيتين ، توسيع الطبقة المزدوجة والتبادل الأيوني متعدد المكونات .

هذا البحث يهدف إلى دراسة تأثير استخدام حقن المياه المنخفضة الملوحة من خلال المقارنة بين حقلي (S & D) ، في الصحراء الغربية في مصر ، يتميزان بخزانات شديدة التبلل بالزيت مع تماثل خصائص الصخور والسوائل بينهما. تم غمر الحقل (S) بمياه منخفضة الملوحة، بينما تم غمر الحقل (D) بمياه عالية الملوحة . لحسن الحظ ، تم تطبيق حقن المياه المنخفضة الملوحة بدون تكلفة إضافية لتحلية المياه حيث أن مصدر المياه لغمر الحقل (S) هو طبقة منخفضة الملوحة ، والتي تحتوي على نسبة ملوحة +/- ٥٠٠٠ جزء في المليون كمجموع المواد الصلبة الذائبة.

أظهرت التجارب المعملية لحقل (S) توافقاً جيداً بين كلا من المياه منخفضة الملوحة المحقونة ومياه الخزان وصخور الخزان. تشير الفحوصات الميكروسكوبية وفحوصات الأشعة السينية إلى وجود الجير كمادة اسمنتية بين جزيئات الصخر بمحتوى الطين الطمي حوالي ٥٪. الكاولينيت هو نوع الطين الشائع بالخزان ، الذي لديه قدرة تبادل منخفضة الكاتيون. هذا التكوين يساعد على اظهار تأثير حقن المياه المنخفضة الملوحة. بالنسبة للحقل (S) فإن مقدار اقصى استخلاص للزيت من الطبقة هو ٤٦ ٪ ، في حين أن قيمته للحقل (D) هو ٣٩ ٪. أحد الأسباب الرئيسية لهذه الزيادة في الحقل (S) هو حقن المياه المنخفضة الملوحة.