

## Effect of salinity degree of injected water on oil recovery from carbonate reservoir

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Water injection is considered the most successful and widespread secondary recovery method. Low salinity water injections is a well-established and proved technique for water flooding application in sandstone rocks to enhance the recovery efficiency; where the water salinity is adapted to a certain degree to extract the highest amount of oil from a reservoir. Reserve-estimation statistics show the significance of oil reserves in carbonate reservoirs, hence this work deals with the carbonate rocks where water flooding may fail due to many reasons, and the most common one is fractures existence in the carbonate rocks. This work applied the water injection for six carbonate (limestone) core samples from Belayim Formation of Middle Miocene age that extracted from an Egyptian offshore oil field in the Gulf of Suez. This carbonate facies is hard, vuggy, fragmented, dolomitic, and highly saturated with oil and considered a good reservoir. Relative permeability test was carried out to investigate the reservoir response in terms of recovery efficiency hence residual oil saturation, when flooding the reservoir with waters having different salinity ratios. Results showed an increase in recovery efficiency for all the tested samples, on applying the low salinity water injection, where all the relative permeability curves displayed wettability modification/alteration toward water wetness properties.

**[Keywords:** Water salinity; Oil recovery; Carbonate; Reservoir]

### Introduction

Water flooding tests were carried out on core samples selected from Belayim Formation that extracted from Al Hamd area, an Egyptian offshore oil field located in the Gulf of Suez (Fig. 1).

Belayim Formation aged Middle Miocene, and represents the beginning of the main Miocene evaporite cycle in the Gulf of Suez, it was not deposited at the extreme northern part of gulf<sup>1</sup>. It ranges in thickness from 53 m to 427 m, and was deposited in a lagoonal to shallow marine setting. It is subdivided into four members from base to top; Baba, Sidri, Feiran and Hammam Faraun. (1) Baba Member comprises mainly of anhydrite with shale subordinates. (2) Sidri Member consists mainly of shale with thin streaks of limestone and/or sandstone. (3) Feiran Member is mainly composed of halite with anhydrite and thin shale interbeds. (4) Hammam Faraun Member consists of shale with sand and/or limestone or dolomite interbeds.

On the high pre-Miocene structures, the Belayim Formation consists of reefal limestone with excellent reservoir characteristics.

The studied core samples belong to Hammam Faraun member, which is coral reef facies (i.e. autochthonous limestone). It is mainly reefal carbonate



Fig. 1 — Location map shows Al Hamd concession area

facies characterized by brownish grey to dark grey colour, hard, vuggy, fragmented, dolomitic, pyritic, carbonaceous matter, highly saturated with oil and considered a good reservoir, so water flooding is a good tool to extract more oil as a secondary recovery.

Water flooding as a mean of secondary recovery for pressure maintenance, dates back to 1865, the use of water flooding as a recovery method did not come into widespread acceptance and use until the early 1950's. Water flooding is accepted generally<sup>2</sup> for some reasons, among them, it is an active agent for displacing oil of light to medium gravity, it is relatively easy to inject into oil-bearing formations and it is available and most importantly inexpensive.

Water flooding success is proved worldwide in sandstone oil reservoirs and also low salinity water flooding is already proved, where it is often believed that lowering brine salinity in order to improve oil recovery is a relatively new theory. The first experiment testing this assumption was published as early as 1967, where an increase in oil recovery when lowering sodium chloride content of the injection brine to 0.1%, was observed<sup>3</sup>.

Many conclusions were mentioned for oil recovery enhancement, among them oil recovery optimization during water flooding requires an alteration of injection water composition<sup>4</sup>, decreasing brine salinity results in an improvement of oil recovery<sup>5,6</sup>. Increase in oil recovery by low salinity water flooding is highly specific to oil/brine/rock interactions and much remains to be learned about the recovery mechanisms under various circumstances<sup>7</sup> and an improvement of recovery efficiency was reported of 5% to 38% and 3% to 17% reduction of residual oil saturation as a result of low salinity flooding<sup>8</sup>.

Oil companies such as Total<sup>9,10</sup>, Shell<sup>11,12,13,14</sup>, Statoil<sup>15,16,17,18</sup> and BP<sup>19,20,21,22</sup>, have all shown a great interest in low salinity water flooding as an enhanced oil recovery method through several research projects. Many researchers studied water quality in carbonate rocks which is known as smart water flooding; to tailor the water ion composition and water salinity to investigate any effect on residual oil saturation. Carbonate rocks have great significance where approximately 50% of petroleum reserves worldwide are found in carbonate reservoirs<sup>23</sup>. Oil recovery from these reservoirs is generally very low usually below 30%, the reason for this is that most carbonate rocks are fractured, of low permeability and of low water wetness<sup>23,24</sup>. Analysis figures from Schlumberger<sup>25</sup>, estimate that 60% of the world's remaining oil, and

40% of its gas reserves are held in carbonate fields. In the case of carbonate formations, the positive results of the smart water flooding are credited to wettability alteration and to interfacial tension reductions between the low salinity injected water and the oil in the carbonate formation<sup>26,27</sup>. The main objective of this study is to investigate the effect of the salinity degree of the injected water on the oil recovery efficiency from the carbonate reservoir.

The aim of this work was achieved through carrying out two runs of the relative permeability tests using two types of injected waters which are rock formation water and the low salinity sea water as an available, closer and cheaper source for water flooding.

### Materials and Methods

Six limestone core samples of Belayim Formation from Al Hamd area were drilled into cylindrical plugs of size 1.5'' diameter to carry out the basic petrophysical measurements on them (Table 1), where they cleaned in solvent reflux soxhlet using toluene and methanol to remove any remains of hydrocarbon and salts respectively, then dried using a drying oven.

Porosity data were measured using matrix-cup helium prosimeter (Heise Gauge type) for grain volume calculation and DEB-200 instrument that follows Archimedes principle for sample bulk volume determination. Air permeability measurements of the studied samples were done using steady state permeameter, after that the clean dry sample were saturated with the synthetic formation water of salinity 15.2% (Table 2) and reduced to immobile

Table 1 — Basic petrophysical properties of the studied samples

Plug ID	Depth (m)	$\phi$ %	K mD	$\rho$ gm/cc
1	1433.13	26.8	408	2.77
2	1434.31	22.8	151	2.79
3	1434.88	22.8	46	2.80
4	1447.20	19.8	278	2.76
5	1448.73	22.0	35	2.80
6	1458.97	26.8	82	2.83

Table 2 — Injection water analysis of the first run of formation water, salinity is 15.2%

Salt	ppm of the first run (formation water)
Sodium bicarbonate	537
Sodium sulphate	1922
Magnesium chloride	19054
Calcium chloride	24996
Sodium chloride	105082

water saturation through flushing with a refined oil of viscosity 24 cp, under back pressure to remove as much water as possible from the pore spaces.

Each sample was loaded then individually into a hydrostatic core holder at 400 psi confining stress and the effective permeability to oil determined in the presence of the initial water saturation for each sample and served as 'base' permeability. For the first run of the measurements, the synthetic formation water (15.2%) was injected into the sample at constant pressure to displace the oil. The produced oil and water incremental volumes were recorded as a function of time, until the water cut reached 0.9995. The effective permeability to water at the residual oil saturation was determined. The sample then was removed from the core holder. The production data were accumulated and the relative permeability to oil and water was calculated for the water displacing oil system<sup>28</sup>. All the previous steps were repeated again for the second run but with another low salinity injected sea water of salinity 3.6% (Table 3).

**Results**

The results of the two runs of injection are displayed in Table (4), where it shows a comparison between the two injected fluids in terms of the following items:

- 1 Average oil recovery (% pv), hence residual oil saturation ( $S_{or}$ ).
- 2 Water saturation ( $S_w$ , %), @ intersection points of relative permeability curves, this is may be an indication of wettability alteration or modification.
- 3 Water relative permeability ( $K_{rw}$ , mD), @ residual oil saturation ( $S_{or}$ ).

The previous results are displayed graphically through the relative permeability curves of the tested samples for the two applied runs (Figs. 2 through 7).

The injection results (Table 4), show an improvement in oil recovery for the sea water of the second run for the all six tested samples, of course accompanied with the reduction in residual oil saturation ( $S_{or}$ ).

Table 3 — Injection water analysis of the second run of sea water, salinity is 3.6%

Salt	ppm of the second run (sea water)
Sodium bicarbonate	165
Sodium sulphate	4052
Magnesium chloride	5132
Calcium chloride	1541
Sodium chloride	24565
Potassium chloride	744

Table 4 — Summary of the main results of the two applied runs

Plug ID	Different injected water salinity					
	1st run (15.2% water salinity)			2nd run (3.6% water salinity)		
	Average oil recovery, % pv	$S_w$ , % @ intersection ( $K_{ro} = K_{rw}$ )	$K_{rw}$ , mD @ $S_{or}$	Average oil recovery, % pv	$S_w$ , % @ intersection ( $K_{ro} = K_{rw}$ )	$K_{rw}$ , mD @ $S_{or}$
1	21.0	53.5	43.8	22.9	55.5	47.3
2	27.7	59.5	11.6	29.8	62.5	12.5
3	30.6	66.5	5.1	31.2	67.5	6.7
4	26.2	70.0	19.5	26.4	73.0	34.3
5	26.3	61.2	4.6	26.6	61.5	4.9
6	30.7	55.8	6.9	34.6	61.6	7.2

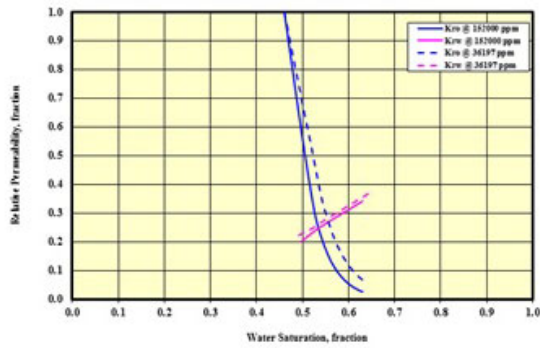


Fig. 2 — Relative permeability versus water saturation of S# 1

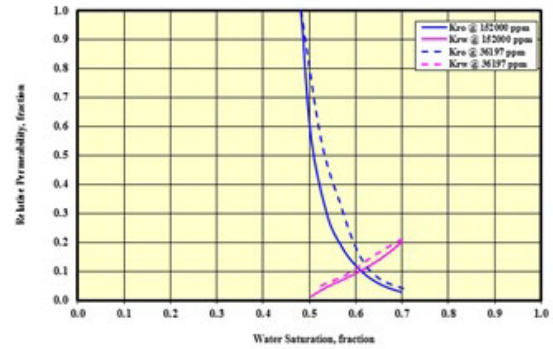


Fig. 6 — Relative permeability versus water saturation of S# 5

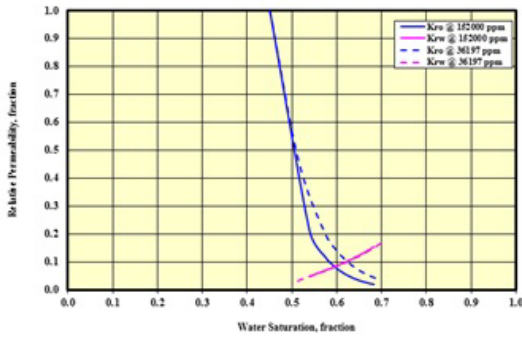


Fig. 3 — Relative permeability versus water saturation of S# 2

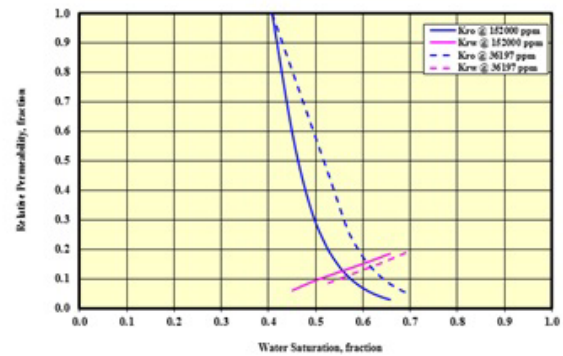


Fig. 7 — Relative permeability versus water saturation of S# 6

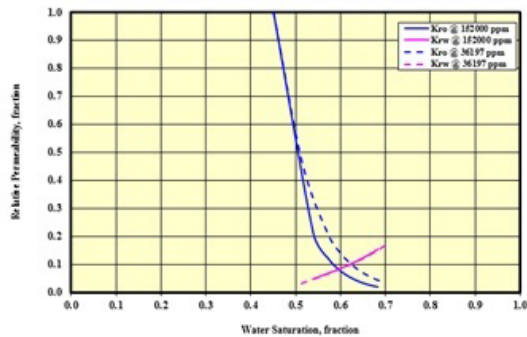


Fig. 4 — Relative permeability versus water saturation of S# 3

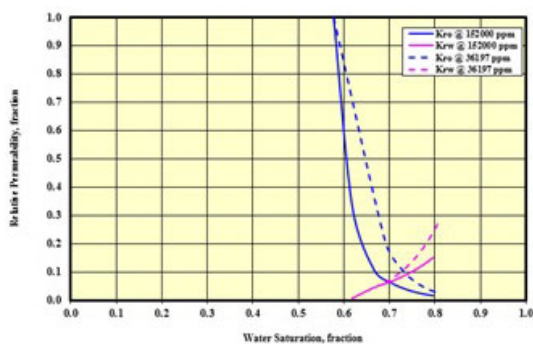


Fig. 5 — Relative permeability versus water saturation of S# 4

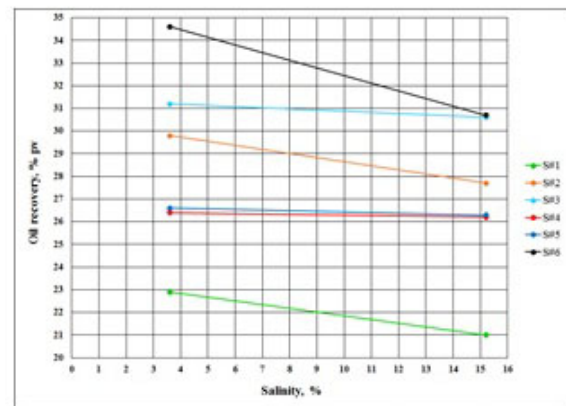


Fig. 8 — Oil recovery versus salinity of the two injection waters

Figures (2) through (7) display that the wettability of the tested plugs in case of the first run using formation water are water wet as a rule of thumb (where water saturation that is more than 50% at intersection point for the solid lines curves, indicates water wet properties), and also show an increase in water wetness properties of the tested plugs during the second run of the low salinity sea water, where all the intersection points of the dotted lines curves shifted to the right. Figure (8), displays oil recovery versus salinity of the two injected waters, where the oil recovery improvement happened for all the

studied samples in different ratios for the low salinity injected sea water.

### Discussion

It is well known that numerous assumption have been mentioned to explain the increase in oil production associated with low salinity water injection, among them brine composition and concentration, increasing pH, interfacial tension reduction, clay migration, and wettability alteration. The effects of injection brine composition and concentration are important factors that affect water flooding, where it is believed that divalent ions are key to the adsorption of oil onto pore surfaces, and may contribute to the residual oil saturation obtained during a normal high salinity water flood<sup>22</sup>.  $\text{Ca}^{+2}$  and  $\text{Mg}^{+2}$  can act as cation bridges between the negatively charged oil and rock, binding the oil to the rock surface. Lowering the salinity of the injected water (as in sea water case) implies a lower concentration of multivalent cations to bind the oil and an expansion of the water layer surrounding the rock. This provides a greater opportunity for the oil to be swept by the imposed flow, thus improving the sweep efficiency. Enhancing oil recovery by increasing pH, was proposed<sup>6</sup>, where a low salinity water is injected into the core increases pH of the effluent from around 7 to 8 up to a pH of 9 or more. Like alkaline flooding, the elevated pH increases the water-wetness of the reservoir, also the low salinity injection was therefore believed to decrease interfacial tension between oil and water by the generation of in-situ surfactants. Migration of fine particles mainly kaolinite, might play a key role in the sensitivity of oil recovery to salinity<sup>5</sup>. It obvious from the relative permeability results that the wettability of the studied samples of Belayim Formation have changed into more water-wet properties while flooding with the low salinity sea water and this was an essential factor for increasing the oil recovery efficiency.

### Conclusion

The results revealed that the use of low salinity sea water as the injection water has a positive effect on the oil recovery from Belayim Formation.

Salinity decreasing was conducive to the increasing of the oil recovery hence decreasing the residual oil saturation, increasing the relative permeability to water at the residual oil saturation and shifting the intersection points of the oil-water relative permeability curves toward more water wetness properties, so the rock wettability characteristics can be

detected qualitatively from the relative permeability curves.

The recovery mechanism confirmed that smart water flooding is able to alter rock wettability toward strong water-wet system which increase oil recovery factor, consequently there is a need to determine the optimum water salinity for getting the maximum oil recovery.

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