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Modeling of A Low Salinity Waterflooding in Carbonate Reservoir

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Abstract

Some studies about low salinity waterflooding (LSW) was carried out to observe the mechanisms of LSW and the response of each reservoir in a certain condition. The majority of topics about LSW are in a laboratory investigation and in a sandstone implementation. Although the benefits of LSW were reported, only a few studies discussed the LSW simulation process, especially in carbonates reservoir. Therefore, this research is deemed necessary to discuss the modeling process of LSW in carbonates reservoir for a comprehensive understanding of the simulation application. One of the primary mechanisms of LSW in carbonate is wettability alteration. The geochemistry software which is used provides the calculation of some reactions that affect the oil recovery mechanism. By developing a homogeneous cubic model with a 5-spot pattern, the simulation scenarios are arranged to compare the injection water using formation water (salinity is about 179,730 ppm) to lower salinity brine by diluting 10 and 20 times of formation water. The LSW process during 50 years improves oil recovery by about 4% higher than formation water injection. But it has the potential increasing oil recovery if we see the trend. It can be concluded that a low salinity waterflooding is an opportune method that is considered to be applied for increasing oil recovery in carbonates reservoir. Even though the process is not immediately visible because it needs time for reaction, it means the sooner LSW implemented is suggested.

Keywords: low salinity waterflooding, enhanced oil recovery, recovery factor, geochemistry, simulation

I. INTRODUCTION

Low salinity waterflooding (LSW) is one of the most discussed enhanced oil recovery (EOR) methods for the last decades. It has been developed from a conventional waterflooding by modifying and lowering the salinity of water injection. In a conventional waterflood, the process is injecting produced water into the reservoir to displace residual oil saturation. While the low salinity waterflooding process is injecting diluted formation water or modifying the concentration of water compositions with lower salinity.

Formerly, injecting lower salinity water was avoided because it brought on clay swelling that could be damaged the formation around the wellbore. Lately, many researchers promote this method as a considered EOR method in terms of a cheaper cost, easier field implementation process, and less environmental impact besides the oil recovery improvement.

Some studies about LSW in sandstone and carbonate reservoirs were carried out to observe the mechanisms of LSW and the response of each reservoir in a certain condition. Although the benefits of LSW were reported, only a few studies discussed the LSW simulation process in carbonates reservoir. The majority of topics about LSW are in a laboratory investigation and in a sandstone implementation. Therefore, this research is deemed necessary to discuss the modeling process of LSW in a carbonate reservoir.

This paper presents a modeling of a low salinity injection process in a carbonate reservoir which aims to cognize the responses or carbonates reservoir when some parameter sensitivities are engaged. This modeling is the best approach method for predicting a field-scale reservoir performance case.

II. LITERATURE REVIEW

Within two decades, there have been a lot of studies that showed the improvement of oil recovery by lowering the ion concentration in injection brine. Some hypotheses were proposed to explain the mechanism of LSW oil recovery. One of primary mechanism which is trusted improving oil recovery on LSW in carbonates reservoir is wettability alteration. Some theories are raised to explicate wettability alteration such as reactive potential determining ion, surface adsorption/desorption (Lager et al, 2006), mineral/particles dissolution (Evje and Hiorth, 2011),

Ligthelm et al (2009) suggested that injecting lower salinity water brought on the expansion of the double layer which caused the dispersion of clay-oil bonded. Lager et al (2006) presented that multiple-component ionic exchange (MIE) between clay mineral and injected water is the explication of oil recovery in the LSW process. The polar compound of oil adsorbed on the clay surface because of the divalent cation presence in connate water (see Figure 1). At low salinity injection, there is an expansion of the electric double layer which means weaken the bonding between polar compound oil with the rock surface. As the result, the monovalent ion will be easier to replace the divalent cation than the polar compound is detached from the clay surface. This process leads to an increase in oil recovery.

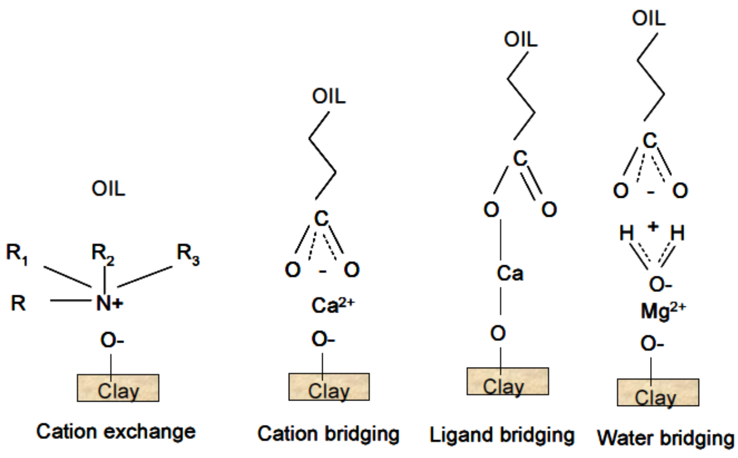

Figure 1. Adhesion Mechanism between Oil Compound and Clay Surface

(Lager et al, 2008)

Evje and Hiorth (2011) presented the calcite dissolution model as the LSW oil recovery mechanism in carbonates reservoir. Tang and Morrow (1999) proposed fine migration as the one of mechanism in wettability alteration. McGuire et al (2005) stated pH increased during LSW that induced the IFT reduction.

Based on the literature studies, some reactions that will occur during the LSW modeling process are shown below. These reactions are a reversible process.

Ion exchange reactions between ions in the solution and adsorbed ion on the mineral surface :

$$Na^+ + \frac{1}{2}(Ca - X_2) \leftrightarrow (Na - X) + \frac{1}{2}Ca^{2+} \quad (1)$$

$$Na^+ + \frac{1}{2}(Mg - X_2) \leftrightarrow (Na - X) + \frac{1}{2}Mg^{2+} \quad (2)$$

$$Na^+ + (H - X_1) \rightleftharpoons H^+ + (Na - X_1) \quad (3)$$

$$SO_4{}^{2-} + 2\,R - COO - X \rightleftharpoons 2R - COO^- + (SO_4 - X_2) \qquad \text{(for carbonates)} \quad (4)$$

where X denotes the clay mineral.

Aqueous Phase Reactions

$$H_2O \rightleftharpoons H^+ + OH^- \quad (5)$$

$$CO_{2(aq)} + H_2O \rightleftharpoons H^+ + HCO_3{}^- \quad (6)$$

$$NaSO_4{}^- \rightleftharpoons Na^+ + SO_4{}^{2-} \qquad \text{(only for carbonates)} \quad (7)$$

$$CaSO_4 \rightleftharpoons Ca^{2+} + SO_4{}^{2-} \qquad \text{(only for carbonates)} \quad (8)$$

$$MgSO_4 \rightleftharpoons Mg^{2+} + SO_4{}^{2-} \qquad \text{(only for carbonates)} \quad (9)$$

Mineral Dissolution Reactions

$$CaCO_3 + H^+ \rightleftharpoons Ca^{2+} + HCO_3{}^- \qquad \text{(Calcite)} \quad (10)$$

$$MgCO_3 + H^+ \rightleftharpoons Mg^{2+} + HCO_3{}^- \qquad \text{(Magnesite)} \quad (11)$$

$$CaMg(CO_3)_2 + 2H^+ \rightleftharpoons Ca^{2+} + 2HCO_3{}^- + Mg^{2+} \qquad \text{(Dolomite)} \quad (12)$$

Those are reactions that will be included in the LSW calculation modeling process.

III. RESEARCH METHODOLOGY

Several simulators have been developed for low salinity modeling. In this study, geochemistry software is used for modeling low salinity water injection. This software can compute ion exchange, aqueous, and mineral dissolution reactions. The reactions are mentioned in the previous section (see equation 1 to 12).

Dang et al (2016) used North Sea Field geological model data for their observation. In this research, the relative permeability data and oil composition use Dang et al (2016) paper, but the geological model uses a homogeneous cubic reservoir to focus the observation of oil recovery on the low salinity process. The simulation process using a geochemistry modeling simulator can provide the ion exchange during low salinity waterflooding.

A three-dimensional homogeneous reservoir model that consists of 21*21*5 grid blocks with properties presented in Table 1. However, the base case simulation does not include the geochemistry reaction.

Table 1 Grid Properties

Parameter	Value
Grid block dimensions	21 * 21 * 5
Grid block sizes	Δx = 160 ft, Δy = 160 ft, Δz = 15 ft
Permeabilities (kh, kv), mD	200
Porosity	0.2
CEC	50
Reservoir Pressure, psi	2000
Reservoir Temperature, F	185
Initial water saturation	0.15

The production started in January 2000 and end in January 2050. Three scenarios are arranged to investigate the effect of low salinity injection. The first is the base case, which is injecting formation water into the reservoir through 4 injection wells. Then, scenario1 is injecting formation water which is diluted 10 times into the reservoir by through a 5-spot pattern. Scenario 2 is the same as scenario 1, but the injected fluid is using 20 times diluted formation water. The injection fluid compositions are shown in Table 2.

Table 2 Brine Composition

Ion	Formation Water (ppm)	LSW-FW 10x diluted (ppm)	LSW-FW 10x diluted (ppm)
Na^+	49,933	4993.3	2496.65
Ca^{2+}	3,248	324.8	162.4
Mg^{2+}	14,501	1450.1	725.05
Cl^-	111,810	11181	5590.5
SO_4^{2-}	234	23.4	11.7
HCO_3^-	3658	0.3658	0.1829
TDS (mg/L)	179,730	17,973	8986.3

The oil composition data and relative permeability data which are referred to in Dang et al (2016) paper are shown in Table 3 and Figure 2.

Table 3 Oil Composition

Ion	Fraction
CO_2	0.01
CH_4	0.19
C_3H_8	0.13
FC_6	0.17
FC_{10}	0.3
FC_{15}	0.15
FC_{20}	0.05

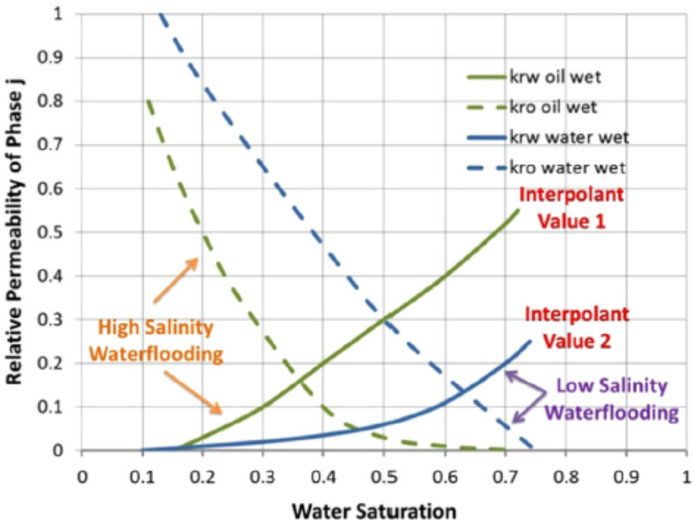

Figure 2 Relative Permeability Curve

IV. FINDING AND DISCUSSION

In the following, the results of the simulation are presented from the gridding to the prediction step. In the initialization step, the homogeneous cubic reservoir results in the original oil in place is about 19 MMSTB. The oil composition is inputted by the WINPROP simulator, while the brine and injected water composition are inputted in Process Wizard (GEM simulator). This simulation considers the ion exchange of Ca^{2+} - X. The calcite and dolomite are the majority of this reservoir. The shifting of permeability also depends on the aqueous and mineral reaction. After identifying the component and the reaction, the well and event are inputted. The 3D view of the model included the position of production and injection wells are shown in Figure 3. The perforation is open on all 5 layers.

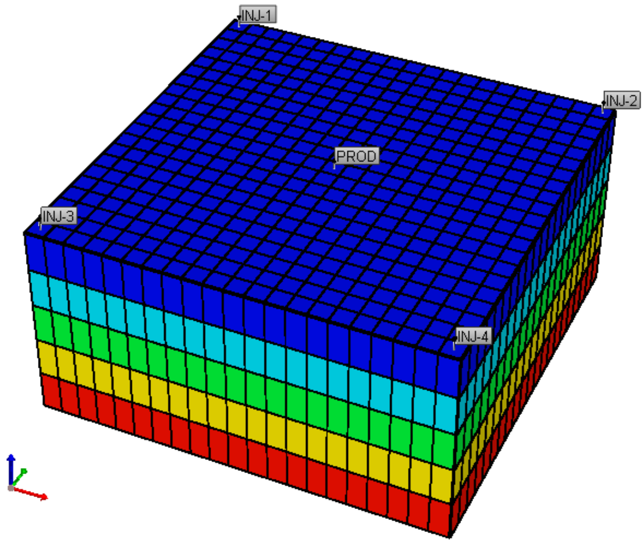

Figure 3 3D Reservoir Model

After running three scenarios, the prediction results are shown in Figure 4. The different oil recovery of scenario 1 and scenario 2 with the base case is 2% and 1%, respectively within a prediction period that is 50 years. The cumulative oil recovery for the base case, scenario1, and scenario 2 is 6.7; 7.3, and 7.1 MMbbl. Even though it seems insignificant improvement of oil recovery, but if we analyze the trends of the graph in Figure 4, the oil cumulative of three scenarios are still tend to increase. It may still increase if the prediction period is extended.

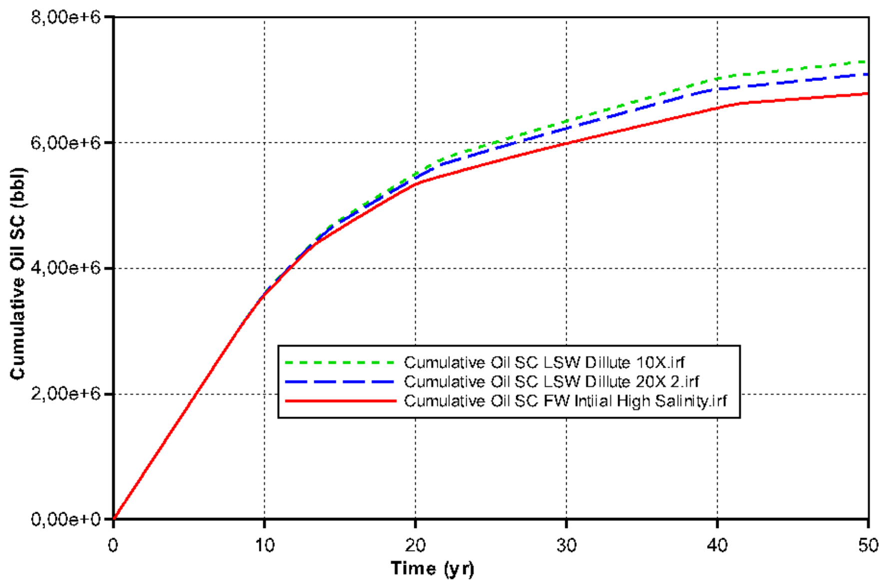

Figure 4 Cumulative Production for Each Scenario

The recovery factor in scenario 1 is slightly higher than in scenario 2. In other words, diluting formation water 10 times tan 20 times is better for this case. It is not the general phenomenon in low salinity. It depends on the properties of rock mineral and aqueous (formation water and injected fluid) composition. There is an explanation about injecting a 20 times dilution formation water gain less oil than 10 times dilution formation water. It because in this simulation process, the rock mineral dissolution and aqueous reaction are considered. By using the Carman-Konzeny equation that calculate permeability reduction as a function change due to mineral precipitation, the more difference salinity between formation water and injected fluid, will disturb the equilibrium condition. The lower oil recovery in scenario 2 indicates the more rock mineral dissolution occurred and it reduces the permeability which brings on the lower oil rate flow.

As known that ion-exchange effects to oil recovery, the composition of the formation water and also reaction selection have to be noticed carefully. From the cumulative oil production graph, we can see the separation of curves after 12 years. It means the low salinity injection water can be seen after 12 years for this case. The low salinity water injection mechanism in oil recovery needs time to react, therefore the sooner implementation will bring on better oil recovery.

Table 4 Production Prediction for Each Scenario

Scenario	OOIP (MMbbl)	Cumulative Oil Production (MMbbl)	Recovery Factor (%)
Base Case: Injecting Formation Water	21.78	6.78	31,14 %
Scenario 1: Injecting Formation Water diluted 10x		7.3	33,51 %
Scenario 2: Injecting Formation Water diluted 20x		7.09	32,58 %

V. CONCLUSION AND FURTHER RESEARCH

The highlight obtained from the results are :

1. a low salinity waterflooding is an opportune method that is considered to be applied for increasing oil recovery in carbonates reservoir. In this case, the low salinity injection response begins to appear after 12 years of injection. Even though the process is not immediately visible because it needs time for reaction, it means the sooner LSW implemented is suggested. The present research is adequate describes the performance of LSW even it is limited in prediction time. It needs continuation research to investigate the best time to inject to gain the optimum oil recovery in LSW's outcome.
2. The less salinity does not mean always increase oil recovery. There is the optimum salinity to gain the highest oil recovery.
3. The reaction type in aqueous and mineral that is included in computing during the simulation process must be selected carefully because it plays role in permeability changes.

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