Investigation of Chemical Mechanisms of Enhanced Oil Recovery by Salinity Variation in Oil-Wet Reservoirs

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***Abstract*—Waterflooding is a widely used enhanced oil recovery technique. However, in oil-wet reservoirs, high water mobility can hinder oil production. This research investigates the effects of high and low salinity waterfloods on oil recovery and water mobility in such reservoirs, also examining the impact on wettability alteration and salt production. The chemical mechanism involves ion exchange and multicomponent ionic diffusion, which promote favorable wettability alteration. A three-dimensional, two-phase (water and oil) model of an initially oil-wet reservoir was developed. Relative permeability curves, generated during simulations, demonstrated wettability changes. Comparing high and low salinity waterfloods assessed the impact of salinity on oil production, water mobility, and salt production. A sensitivity analysis of two injection well patterns—five-spot and direct line drive—was conducted to determine the optimal injection strategy. Low salinity waterflooding achieved approximately 80% recovery, with a cumulative oil production of 0.45 MMSTB. This approach significantly prolonged the water cut and reduced salt production at the production well. The results demonstrate that lowering injection water salinity is an effective strategy for enhancing oil recovery in oil-wet reservoirs. This technique mitigates the negative impacts of high-water mobility, alters wettability favorably, and minimizes salt production, leading to substantially improved oil recovery.**

Keywords—waterflooding, wettability, permeability, salinity, simulation, production.

I. Introduction

Based on formation characteristics, fluid characteristics, reservoir heterogeneities, and PVT characteristics of the reservoir, oil recovery during the life of a reservoir is split into three stages [1]. The main recovery is based on the natural energy of the reservoir and has a recovery factor that is less than 30% of OIIP. Primary recovery also includes artificial lift techniques. The recovery from the secondary mechanism is between 30 and 50 percent of OIIP [2]. Waterflooding was first utilized as a pressure maintenance source for oil recovery in 1880, but it is now universally acknowledged as one of the most popular fluid injection techniques, mainly from the United States, between 1930 and 1950 [3].

The low salinity waterflooding (LSF) EOR technology improves oil recovery by reducing the salinity of the injection water. In the last ten years, low saline waterflooding (LSW) has emerged as a new and promising enhanced oil recovery strategy for carbonate and sandstone reservoirs [4]. The low saline waterflooding has gained a lot of interest from the oil sector due to its simplicity and inexpensive cost. When Bernard and his colleagues tested the oil recovery using (NaCl) sodium chloride brine injection varying from 0-1% with distilled water injection. Additionally, their research has indicated that the injection of sodium chloride brine, ranging from 1 to 15%, has no impact on oil recovery [5].

The recovery of oil during the injection of low saline water depends on a number of reservoir parameters. The infusion of low saline water has no impact on oil recovery at zero initial water saturation [6]. Additionally, it is looked at how oil recovery using low-saline water grows as the saturation of connate water increases. They developed low saline waterflooding (LSW) as an incremental oil recovery [7]. For the evaluation of oil recovery using low saline waterflooding, initial connate water saturation is therefore a necessary requirement [8]. Additionally, the recovery of the low saline waterflooding process is greatly influenced by the presence of clay particles in reservoirs. As previously indicated, the significance of low saline water injection for enhancing oil recovery is widely recognized. It is claimed that clay hydration increases sweep effectiveness. When clay is moistened, it swells, reducing the amount of pore space accessible for both oil and water, which improves oil recovery [9].

In the laboratory core flood test and at the field scale, it is demonstrated that Low Salinity waterflooding improves oil recovery. The suggested mechanisms for low-salinity waterfloods are listed below [10]:

- Increased pH
- Fines migration
- Multicomponent Ionic Exchange (MIE)
- Double Layer Expansion (DLE)
- Wettability Alteration

II. Problem Statement

In this study, water is injected through an injector using both low- and high-saline water injection procedures, and oil is recovered from the production well. The following undesired issues were discovered in this simulation study:

- Earlier water breakthrough
- High salt production rate
- Unaltered oil-wet reservoir conditions

Predictive modelling can be used to identify and fix the existing challenges.

III. Objectives of Study

The objectives of this study are:

• To choose an optimum injection design (such as direct line drive and five spot pattern) for an effective displacement of the oil.

• To study the effect of low and high saline water injection in oil wet sandstone reservoir.

The objective of this study is to evaluate the performance of a sandstone reservoir following the injection of low and high salinity water. The reader is intended to develop a clearer understanding of the mechanisms by which low saline water removes oil from reservoirs and changes the wettability of formations from oil-wet to water-wet, improving oil recovery. For the purpose of choosing an optimized injection method to achieve maximum oil recovery, a sensitivity analysis for various injection well patterns are also performed.

IV. Methodology

The performance of an oil-wet sandstone reservoir under low and high salinity waterflooding is determined in this experiment. A flowchart in Figure 1 shows a brief overview of the steps that have been followed in this work. The reservoir data was first obtained via a literature review, and after that, a simulation model was created using a black oil simulator, such as CMG (a commercially available simulation software). In order to determine the best injection technique, simulations for continuous low- and high-saline water injection were run. Later, a sensitivity analysis was performed using simulated data for the five-spot pattern and direct line drive well injection techniques. After that, based on technical factors including water cut, oil output, and salt production, the best injection well plan was chosen in the conclusion section.

Case Study:

A part of Shaybah oil field is under consideration in this study which is located in Rub'al Khali desert in Saudi Arabia. A well was spud in this field and is now under a need to waterflood, this study gives a brief consideration whether high saline or low saline water will be most efficient in order to produce oil from this field in commercial quantity. Reservoir specifications are taken and a simulation model was generated by considering that this model replicate the original reservoir conditions and methods that are tested in the simulation will be best applicable on the actual reservoir.

Description of reservoir model:

In this study, a 3D reservoir model with a square geometry of 334 acres area is simulated on a black oil simulator. The reservoir model has dimensions of 492 ft, 492 ft, and 30 ft in I, J, and K directions, respectively. The developed model is heterogeneous so, it compromises 50, 50 grid blocks in the I and J direction respectively but has 6 layers in the K direction. At the Initial stage, there are two active phases present in the reservoir i.e., oil and water. The reservoir has a permeability of 275-525 md and porosity of 23-31%.

An injection well and a production well are located on the opposite corners of the model. Injection well is represented by INJ and production well is represented by OP in Figure 1. The simulation is carried out for a period of 5 years.

Developing a Reservoir Model:

In this study, the simulation for the base case is carried out in the following steps:

Model Dimension:

In CMG, the first step for developing a model is to define the title of the run, geometry to be used, number of cells in each direction, number of wells in the model, and starting date of the simulation. This information is defined in the RUNSPEC section.

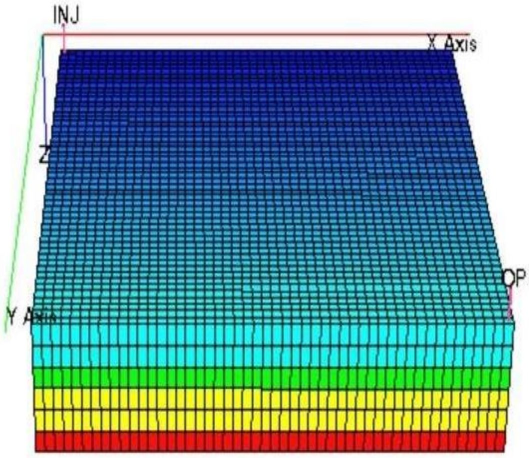


Figure 1. A 3D reservoir model representing INJ and OP.

Grid and Rock Properties:

The second step for developing a model is to define the number of grid cells in I, J, and K directions, dimensions of cells, the permeability of cells, and porosity of cells. This information is defined in the GRID section.

As the reservoir is heterogeneous it has different permeability and porosity in the I, J, and K directions.

Fluid Properties:

The third step for developing a model is to define the concentration of oil and water at the surface, the formation volume factor, viscosity of water and oil, reservoir pressure, rock compressibility, and water compressibility. This information is defined in the PROPS section.

Initial Conditions:

The fourth step for developing a model is to define initial reservoir pressure, saturation conditions, and water-oil contact. This information is defined in the SOLUTION section.

Production Schedule:

The last step for developing a model is to define the names of wells, their positions and groups, the completion period for each well, and specify the injector and producer controls. This information is defined in the SCHEDULE section.

Salinity limits and relative permeability:

The literature research revealed that the threshold limit for low saline waterflooding effects is between 500 and 5000 ppm. As a result, the range of low saline waterflooding is kept within the threshold limit in this study. As a result, depending on the salt content, it is important to change the relative permeability for oil-water phases and the saturation endpoints for the modelling of low saline waterfloods. Therefore, the reservoir's wettability has a significant impact on low salinity. The following Corey model equations have been applied to produce the relative permeability and saturation profiles that depict oil-wet and water-wet conditions in the reservoir [11]:

$$K_{rw} = S*^{N_w} + E_w \quad (1)$$

$$K_{ro} = (1 - S*)^{N_o} E_o \quad (2)$$

$$E_w = K_{rw}(S_{or}) \quad (3)$$

$$E_o = K_{ro}(S_{wi}) \quad (4)$$

$$S^* = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}} \quad (5)$$

K_{rw} - Relative permeability to water

K_{ro} - Relative permeability to oil

S_w - Water saturation

S^* - Normalized water saturation

N_w - Empirical constant for water

N_o - Empirical constant for oil

S_{or} - Residual oil saturation

S_{wi} - Irreducible water saturation

E_w - Endpoint relative permeability for water

E_o - Endpoint relative permeability for oil

V. Results and Discussions

The underlying reservoir model in this work was first simulated for continuous low salinity (LS) and high salinity (HS) water injection. After that, a sensitivity analysis for different well injection methods, including a direct line and a five-spot pattern, was carried out. For a total of five years, the simulation was run.

Comparison of low and high saline waterflooding:

In this study, primarily, two cases are simulated to inspect the effects of salinity on the behavior of oil-wet sandstone reservoirs. The two cases are defined as:

I. Continuous injection of Low Saline (LS) water (1000 ppm)

II. Continuous injection of High Saline (HS) water (45000 ppm)

Oil Saturation Response:

According to the simulation's findings, low saline water injection produced a significant amount of oil. Whereas high saline water injection left almost 53% of residual oil behind. Saturation response of both high salinity waterflooding and low salinity waterflooding is represented in Figure 2 and 3 respectively.

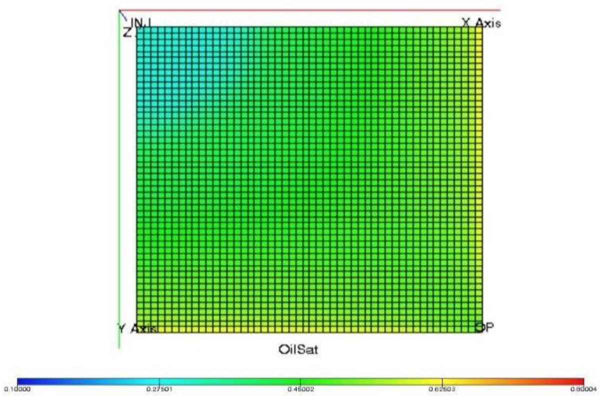
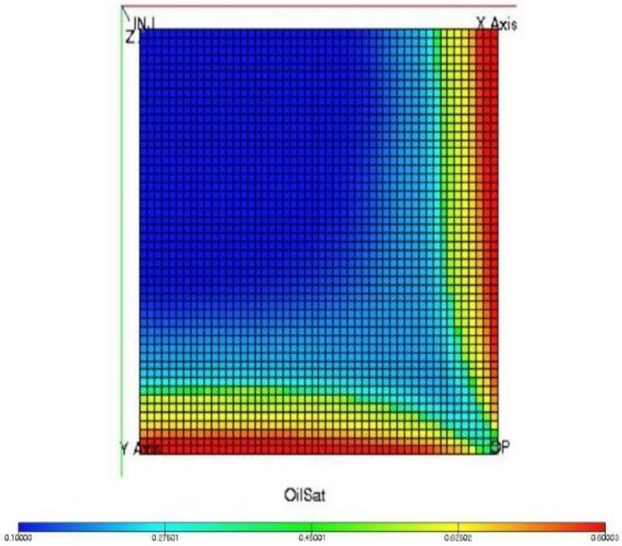


Figure 2. Saturation response over high saline



waterflooding.

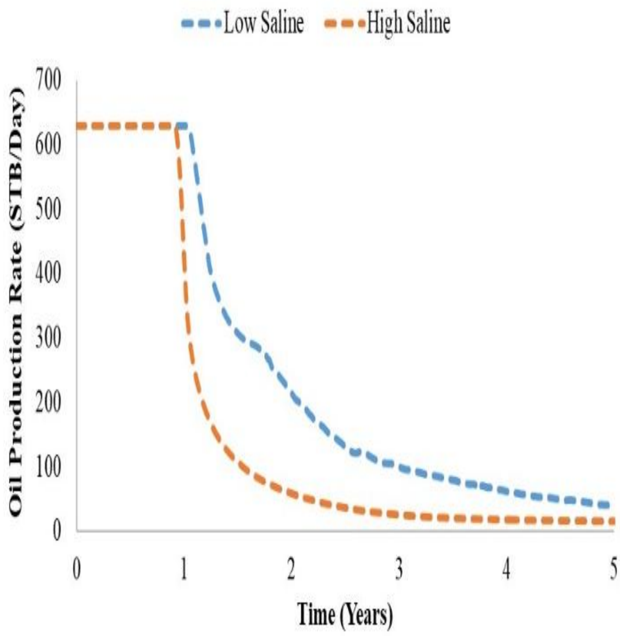
Figure 3. Saturation response over low saline waterflooding.

The wettability alteration is what caused the considerable oil displacement from the reservoir. Additionally, the clay particles are retained undistributed because the rock is held in an oil-wet condition, which contributes to the reduced displacement effectiveness in high saline water injection.

Field Oil Production Rate:

Figure 4 shows that the oil production rate for both low- and high-saline waterflooding is constant for the first year at the controlled volume of 630 STB/Day. At the conclusion of the first year, the production rate tends to decline, and by the end of the second year, it has reached 100 STB/Day for the low saline water injection and 25 STB/Day for the high saline water injection.

Similar trends may be seen for the third, fourth-, and fifth-years' producing periods. The field production rates for low



salinity and high salinity are 39 STB/Day and 15 STB/Day, respectively, at the end of the fifth year.

Figure 4. Oil production rate response for low and high saline waterflooding.

Field Cumulative Oil Production with Oil Recovery:

The rates of oil production have a direct impact on the total amount of oil produced. Since oil is producing quite rapidly when low saline water is injected than when high saline water is injected, the cumulative oil production obtained during low saline waterflooding is also higher, coming in at 0.45 MMSTB at the end of five years as opposed to 0.3 MMSTB for the high saline flooding. Figure 5 displays a summary of the total oil production during the past five years.

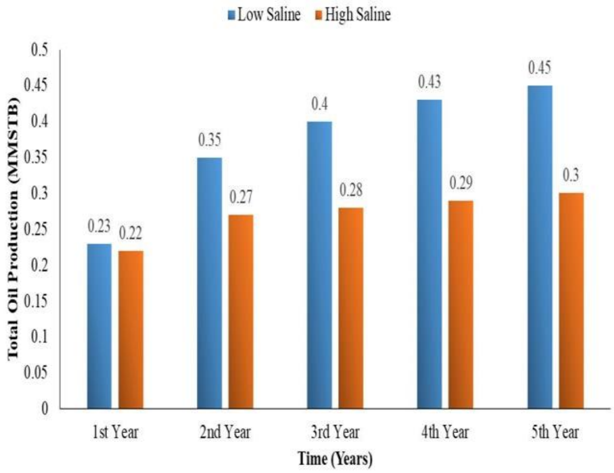
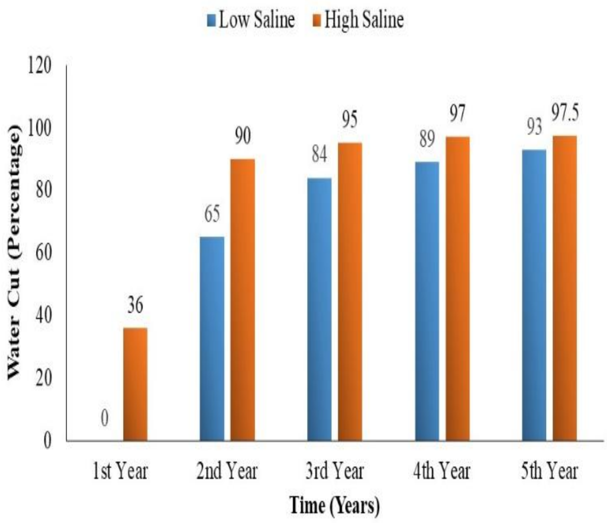


Figure 5. Cumulative oil production response for low and high saline waterflooding.

Field Oil Production Rate:

The impact of water mobility on the producer's water cut values has also been noticed along with the impact on oil production. Figure 6 displays the water cut reaction for both low and high saline waterfloods. The results demonstrate that low salinity waterflooding does not create any water, whereas high salinity waterflooding results in a water cut of 36% at the end of the first year, indicating an earlier water breakthrough. The water cut has been seen for low salinity during the second year, although its value is smaller than flooding from high salinity water. The pattern remains through the fifth year, when the water cut value for low salinity reaches 93% and for



high salinity it reaches 97.5%. The results suggest that low salinity waterflooding still has less water mobility than high salinity flooding.

Figure 6. Water cut response for low and high saline waterflooding.

Field Salt Production:

The production of salt at the producer is a key issue in this research. As can be seen in Figure 7, the impact on salt formation as a reaction to the altered salinity of the injected water has also been studied.

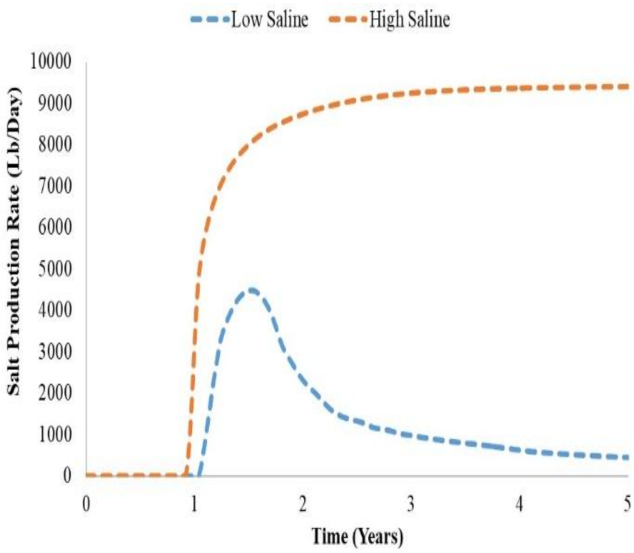


Figure 7. Salt production rate response for low and high saline waterflooding.

The findings demonstrate that in both salinity instances, there is initially no salt production. By the end of the first year, the producer's salt output for high salinity injection had increased to 35,000 lb/day, while it remained nil for low salinity. The production of salt for high salinity rose at the end of the second year to close to 9000 lb/day and remained at this rate for the following five years. When compared to high salinity, low salinity's salt output rises to 4450 lb/day until the middle of the second year, then begins to fall off and lasts for five years. Figure 7 depicts the trend in salt production for both low and high salinities. The findings show that increased salt production occurs in situations of excessive salinity, which may lead to serious corrosion issues as well as damage to equipment located on the surface.

Therefore, based on higher oil production rate, later water cut, and lower salt production, it has been discovered by comparing low and high salinity examples that the injection of low saline water delivers better performance in an oil-wet sandstone reservoir. In order to further analyze the sensitivity of the well injection pattern, the low salinity case is now used.

VI. Conclusion

1. The simulation findings highlight that low salinity water injection significantly enhances oil recovery by effectively altering the wettability of the reservoir, leading to greater oil displacement. In contrast, high salinity water injection results in a higher residual oil content, with 53% of the oil remaining unrecovered.

2. Low-saline waterflooding demonstrates a consistently higher oil production rate compared to high-saline

waterflooding over a five-year period, with a notably slower decline in production, highlighting its greater effectiveness in maintaining reservoir productivity.

3. Low-salinity water injection results in significantly higher cumulative oil production (0.45 MMSTB) and recovery (80%) over five years compared to high-salinity injection (0.3 MMSTB and 57% recovery), attributed to the change in wettability from oil-wet to water-wet, leading to reduced residual oil saturation.

4. Low-salinity waterflooding demonstrates lower water mobility than high-salinity flooding, exhibiting a delayed water breakthrough and consistently lower water cut values over five years, although both eventually reach high water cut percentages.

5. High-salinity water injection leads to significantly higher salt production (peaking at 35,000 lb/day in the first year and stabilizing around 9,000 lb/day thereafter) compared to low-salinity injection (peaking at 4,450 lb/day and then declining), indicating a greater risk of corrosion and equipment damage associated with high-salinity flooding.

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