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# ОПТИМИЗАЦИЯ ЗАВОДНЕНИЯ С ИСПОЛЬЗОВАНИЕМ НИЗКОМИНЕРАЛИЗОВАННОЙ ВОДЫ ДЛЯ ПОВЫШЕНИЯ НЕФТЕОТДАЧИ В НИГЕРИЙСКОМ МЕСТОРОЖДЕНИИ

# OPTIMIZATION OF WATERFLOODING USING LOW SALINITY WATER INJECTION TO IMPROVE OIL RECOVERY IN THE NIGERIAN OILFIELD (X).

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**Аннотация.** Заводнение уже давно используется для улучшения нефтеотдачи во многих месторождениях. Снижение дебита нефти и увеличение обводненности за счет снижения пластового давления стали основной причиной процесса проектирования заводнений в течение многих лет, и нефтяные компании применяли различные стратегии для поддержания пластового давления и увеличения суммарной добычи. Месторождение X в Нигерии находится на поздней стадии разработки, средняя обводненность составляет более 85 %, большинство оставшихся запасов трудноизвлекаемое. В данной работе проведено экспериментальное исследование о возможности использования низкоминерализованного заводнения для повышения нефтеотдачи. Влияние закачиваемой воды на эффективность вытеснения низкоминерализованной воды было исследовано с морской водой при 35,091 миллионной доли (м.д) и двух смоделированных вод, а именно SE-W1 при 260,324 м.д, SE-W2 при 160,183 м.д. и пластовой воды при 224888 м.д. Результаты этого набора экспериментов показали, что SE-W2 минерализованность 5000 ppm является оптимальной системой для потенциального коллектора.

**Ключевые слова:** Низкоминерализованное заводнение, МУН, относительная пористость, вторичное заводнение.

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**Annotation.** Water flooding has for a long time been employed to improve oil recovery in many oil fields. Declining oil production rate and increasing watercut due to reducing reservoir pressure was the main reason of water flooding design process for many years and oil companies adopted different strategies to maintain reservoir pressure and increase cumulative production. The X field in Nigeria is in the late stage of development, the average watercut is more than 85 %, majority of the remaining reserves are difficult to recover. In this paper an experimental investigation on the possibility of using low salinity waterflooding to improve oil recovery was conducted. The effect of injection brine salinity on the displacement efficiency of low water salinity flooding was investigated using sea water at 35,091 ppm and two simulated water, namely SE-W1 at 260,324 ppm, SE-W2 at 160,183 ppm and formation water at 224888 ppm. The results of this set of experiments revealed that SE-W2 salinity of 5,000 ppm is the optimum system for the candidate reservoir.

**Keywords:** Low Salinity Waterflooding; EOR; Relative Permeability; Secondary Flooding.

## 1 Introduction

Water injection to improve the oil recovery has been employed for many years. The effect of injection brine composition and concentration on the displacement efficiency has been ignored in the design of water flooding in the past. Historically avoiding formation damage by making sure no interaction between injected brine and indigenous brine will take place during water flooding was the main design parameter of water flooding. [1] concluded that oil recovery optimization during water flooding requires alteration of injection water brine composition. [2]; [3] concluded that decreasing brine salinity results in an improvement of oil recovery.

Low salinity waterflooding is an emerging EOR mechanism in the oil and gas industry. [4] indicated that low salinity flooding of more than 20 sandstone cores at reservoir conditions in secondary and tertiary modes had been conducted as reported in the literature. They also reported an improvement of recovery efficiency of 5 % to 38 % and 3 % to 17 % reduction of residual oil saturation as a result of low salinity flooding.

[5] made a comparison between sea water and de-ionized water flooding in a secondary mode and demonstrated that using deionizer water produced a significant improvement in oil recovery over seawater.

Low salinity waterflooding is injection of brines with a lower salinity, or at least a different salinity, than the initial formation brine salinity. If clay is present in the reservoir together with connate water this may cause reactions between the injected brine, the reservoir brine and the clay surface. These reactions are thought to trigger the pH in the reservoir for optimum conditions, start up an ionic exchange between the ions from the injected and reservoir brine or potentially mobilize some of the stuck oil by production of fines. This again might reduce the residual oil saturation and enhance oil recovery.

[2] stated that fine migration during low salinity water floods of Brea sandstones cores is the main mechanism responsible to the improvement of oil recovery. They indicated that the exposure of rock surface as a result of fine migration is the mechanism behind alteration of the system wettability. On the other hand, high salinity water floods do not react with clays and as a result of that the reservoir rock maintains its wettability condition. Detachment of clay particles from the rock surfaces and reduction of permeability associated with low salinity flooding (less than 1550 TDS) were also reported [2 and 6] revealed both release of fine and high pH in low salinity flooding. They had noticed a significant change in permeability of the system at a pH higher than 9 which indicated a formation damage caused by fine migration. [7] reported that cation exchange capacity (CEC) of clay sandstones plays a major rule on fine migration. [8] concluded that the reduction of formation permeability during water flooding of sandstone is mainly due high cation exchange capacity. [8 and 9] indicated that the permeability reduction will take placers if the ionic strength of the injected water is equal to or less than, the critical flocculation concentration (CFC). The CFC is strongly dependent on the relative concentration of divalent cations such as Ca2+ and Mg2+. Divalent cations lower the Zeta potential resulting in the lowering of the repulsive force and that leads to clay stabilization. Tang and Morrow 1999 indicated that low salinity water flooding can result in fine migration. On the other hand, BP reported a number of corefloods experiments using its LoSal™ EOR technology have demonstrated improved oil recovery, with no fine migration or permeability reduction. Some laboratory work indicated a rise of pH of produced water as function of pore volume injected [10], see Fig. 1.

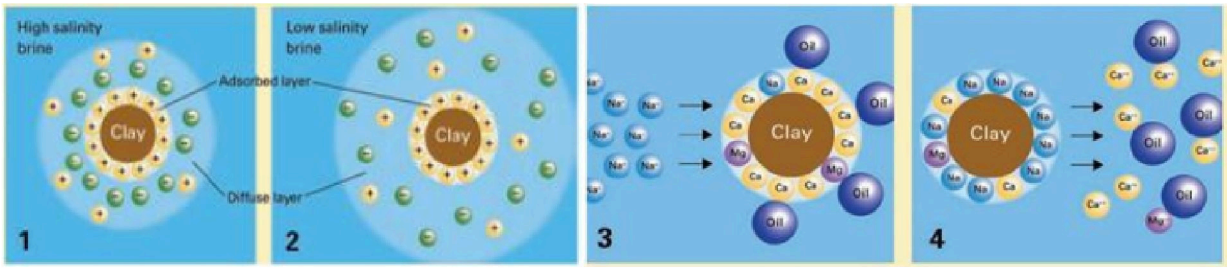



**Figure 1 – The concept of the double layer [12]**

[11] performed experiments on outcrops and reservoir sandstones to compare secondary and tertiary oil recovery by low salinity waterflooding. Both single and two – phase experiments were performed, and pressure drop and pH were continuously monitored. The single – phase coreflooding resulted in an increase in pH from 7.7 to 8.8 during low salinity waterflooding, and fines production was observed during some of the floodings. Incremental recovery was thought to be coincident with the decrease in salinity and increase in pH on the Berea outcrops. Similar pH increases were not observed during LSW in the reservoir sandstone. Among each rock type and oil combination, secondary mode experiments produced more oil than the tertiary experiments. The incremental recovery from the secondary waterflooding varied from 6–22 % compared to the tertiary recovery. [5] observed similar trends during waterflooding on Berea core samples with different brines from a Middle East field. In all cases, the injection brine with the lowest salinity gave the highest recovery during secondary recovery mode. The reason for this they concluded that could be due to cation exchanges taking place, thus reducing the attracting forces between crude oil and the rock surface by changing the rock surface charge.

Overall in the literature, the mechanisms behind the low salinity waterflooding are still not completely understood. A number of different proposed explanations have, however, been presented. An overview of the most plausible explanations is proposed.

### 1.1 Multicomponent Ionic Exchange

The Multicomponent Ionic Exchange (MIE) is a theory based on chemical investigations of interactions between the reservoir brine and the injection brines. Reservoir, especially oil wet, sandstones contain some clay particles within the sand particles that have a negatively charged surface. The oil in these reservoirs is

held on to the surface of the negatively charged clay particles mainly due to divalent cations, such as $Ca^{+}$ and $Mg^{2+}$, positively charged ions that can form two bonds with other ions. As a result, the oil in these reservoirs might form complex organic polar compounds.

Free cations from the injected fluid might react with the divalent ions in the diffuse layers. For example might free $Na^{+}$ ions exchange with the divalent ions, such as $Mg^{2+}$ and $Ca^{+}$, holding the oil in place and thus release the oil stuck in the adsorbed layer as depicted in figure 1.

### 1.2 pH alteration

The pH is a measure of acidity or basicity of an aqueous solution, and depends on the amount of hydrogen ions, $H^{+}$, in place [13]. High concentration of $H^{+}$-ions yields acidic conditions, low pH, while a basic condition is the opposite leading to high pH. Most connate water in reservoirs is considered to be acidic due to dissolved $CO_2$, $H_2S$ and other sour atoms and a pH around 5–6 is expected. This low pH environment enhances the adsorption of both acidic and basic components onto the clay surface [14]. The presence of especially $CO_2$ is suggested to work as a pH buffer, such that the pH of a reservoir up to 10 is unlikely in most petroleum reservoirs.

During LSW, a local increase in pH close to the clay surface has been observed during several LSW laboratory experiment [10, 14 and 15]. [10] proposed this to be due to two simultaneous reactions. A dissolution of carbonates which results in an excess of $OH^{-}$, and a cation exchange between clay minerals and the invading water.

$$CaCO_3 = Ca^{2+} + CO_3^{-}; \quad (1)$$

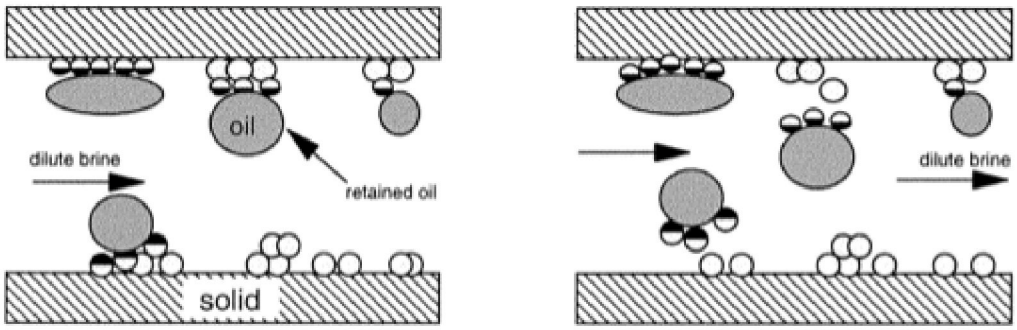
$$CO_3^{2-} + H_2O = HCO_3^{-} + OH^{-}. \quad (2)$$

### 1.3 Fines Migration

Production of fines has been observed several times in sandstone reservoirs in conjunction with low salinity waterflooding (LSW), and the reason for this phenomenon has widely been discussed in the literature and considered as one of the reasons for the low salinity effects (LSE).

[2] observed production of fines during LSW of a CS-sandstone. During the LSW, a significant permeability reduction was observed. This was thought to be due to that migration of fines blocked some of the available pore space. They also concluded that the possibility of fines migration was a necessity because the LSE was eliminated during firing/acidizing of a Berea sandstone core, and waterflooding of this core showed almost no additional oil recovery by LSW. Further on [2] discussed the theory regarding fines migration in details

[2] suggested that diluted brine injection lead to mobilization of the trapped oil as a result of migration of fines. This is illustrated in Figure 3–7 above and was thought to increase the oil recovery. The amount of extra oil produced was, however, considered to be greatly affected by the COBR interaction. If for instance a core was 100 % saturated with oil, such that no connate water was in place, no additional oil recovery was observed during LSW




Retained oil before injection partial mobilization of residual oil dilute brine. Through detachment of fines.

**Figure 2 – Mobilization of trapped oil due to migration of fines [2]**

All the proposed mechanisms tend to yield a wettability alteration towards more water-wet conditions. This is mainly a result of the chemical reactions happening between the clay surface and the injected and reservoir brines. These reactions might decrease the residual oil saturation and increase the oil recovery by mobilization of some of the trapped oil. The reduction in residual oil saturation is dependent on the initial rock properties and strongly dependent on the amount of clay in the reservoirs and the presence of and the salinity of the connate brine.

## 2. Description of experiments

### 2.1 Apparatus and Materials

Reservoir crude oil from X field was used in all experiments. The oil was filtered through a 5.0 lm filter paper (with a vacuum pump) to remove any possible solid particles. The oil API gravity and viscosity are 34 and 3.08 cp measured at room temperature (25 °C), respectively.

The salinity of the employed waters was varied from original salinity to 1,000 ppm and used in the displacement of oil in selected core samples. The results of this set of experiments revealed that SE-W2 salinity of 5,000 ppm is the optimum system for the candidate reservoir.

Formation water (FW) (34,900 ppm), 2 simulated brine, – SE-W1 at 260,324 ppm and SE-W2 at 160,183 ppm were used to determine the optimum salinity system for the oil recovery of the candidate reservoir. The salinity of the employed waters was varied from original salinity to 1,000 ppm and used in the displacement of oil in selected core samples.

Table 1 shows the analysis of these water samples.

#### 2.1.1 Core samples

Thirteen core samples representing different well depths were selected for mineralogical analysis using an X-ray diffraction (Philips X-ray diffracto-meter model PW/1840). The objective of the analysis was to make sure that rock typing should be considered in the preparation of composite cores. The results of the analysis indicated that there was no mineralogy variation in well P12 as presented in Table 3. Thirteen secondary single core (SC) water flooding tests were conducted to determine the optimum salinity system. Six CC samples were prepared using cores representing various core categories as shown in Table 4. All of the CCs were arranged in a random order with an overall average permeability equal to well P12 average permeability of 18 md and length of 31 cm. The cores were cleaned and saturated with oil at connate water saturation employing the current industry standard procedure. The sandstone cores used for the tests were aged in oil for 14 days, to restore their original wettability. Actual oil sample from the Niger Delta field of interest was used as the oleic phase in all of the experiments and standard cleaning procedures were implemented between various displacements.

**Table 1 – Analysis of water samples**

| Type | $Ca^{++}$ | $Mg^{++}$ | $Na^{+}$ | $Fe^{+++}$ | $HCO_3^-$ | $Cl^-$ | $SO_4^-$ | TDS salinity (ppm) |
|---|---|---|---|---|---|---|---|---|
| Formation water | 21,972 | 2,631 | 59,907 | – | – | 141,066 | 302 | 224,888 |
| SE-W1 | 16,337 | 2,149 | 75,825 | 248 | – | 165,220 | 545 | 260,324 |
| SE-W2 | 12,399 | 2,029 | 47,089 | – | 415 | 97,885 | 366 | 160,183 |
| SE-W3 | 699 | 853 | 14,089 | – | 203 | 18,987 | 260 | 35,091 |

All the brines used for the experiments were characterized by first measuring pH, conductivity (S / M), viscosity (Cp) & density (g / cm). Table 2 shows the physical and chemical details of the brines used in the study.

**Table 2 – Physical and chemical properties of the studies crude oil**

| Physical properties | Values |
|---|---|
| Density (ambient conditions), $kg/m^3$ | 866.5 |
| Viscosity (ambient conditions), mPa | 9.5 |
| Major sediments and water, Vol % | 0.5 |
| Molecular weight, g/g mole | 215 |
| Chemical properties | weight % |
| Saturated | 48.4 |
| Aromatics | 33.5 |
| Resins | 13.2 |
| Asphaltenes | 4.9 |

Ten core samples representing different depths of the reservoir in the study area were obtained from well P12 and their respective measured permeabilities, porosity and mean pore sizes are shown in Table 2–6. They were selected for mineralogical analysis using X-ray diffraction (Philips X-ray diffracto-meter model PW / 1840). The aim of the analysis was to make sure that rock typing should be taken into account when preparing composite rods. Thirteen secondary single-core (SC) water flood tests were conducted to determine the optimum salinity system as adapted after [17]. The core samples were purified and saturated with petroleum under connate water saturation using the current industry standard procedure. The sandstone core used for testing was aged in oil for 14 days to restore its original wettability.

**Table 3 – Characteristics of the studied core samples**

| Core samples | Core diameter (cm) | Core length (cm) | Porosiy (%) | Permeability (mD) | Volume of pore space (ml) | Initial water saturation |
|---|---|---|---|---|---|---|
| 1 | 5,8 | 35 | 18 | 54 | 129,7 | 22 |
| 2 | 3,2 | 35 | 12,5 | 1 | 28,48 | 19 |
| 3 | 3,2 | 35 | 14 | 12 | 30,33 | 24 |
| 4 | 3,2 | 35 | 16 | 14 | 32,33 | 23 |
| 5 | 3,2 | 35 | 16 | 54 | 129,7 | 22 |
| 6 | 3,2 | 35 | 17 | 34 | 28,48 | 19 |
| 7 | 3,2 | 35 | 16 | 25 | 30,33 | 24 |
| 8 | 3,2 | 35 | 18,3 | 18 | 32,33 | 23 |
| 9 | 3,2 | 35 | 17 | 18 | 32,33 | 20 |
| 10 | 3,2 | 35 | 18 | 18 | 32,33 | 22 |

### 2.1.2 Experimental procedure

Three types of core flooding experiments were carried out in the present study, which include high-salinity single-core flooding (HSSC), medium salinity single-core flooding (MSSC), and low salinity single-core flooding (LSSC). All the cores were impregnated to form a salt solution, after cleaning the core, to determine the pore volume and absolute permeability. Then they were delivered in relic water by saturation with flooding with crude oil at a high flow rate (160 cm/h). All experiments consisted of the following stages:

– All core samples were fully saturated with formation water (brine) under reservoir conditions to determine porosity;
– Determination of the volume of pore space and absolute permeability using Darcy's law;
– Crude oil has absorbed and flooded the connate water with saturation, and
– The end point of oil permeability.

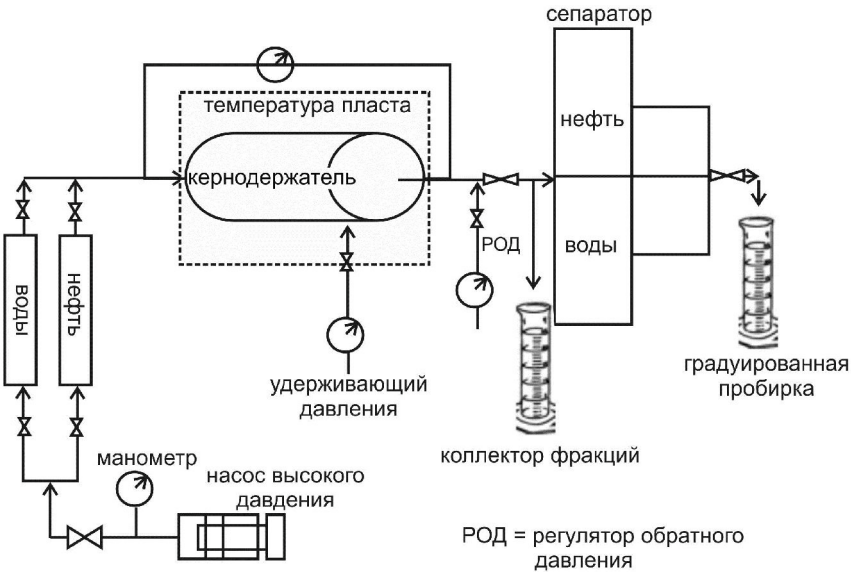



**Figure 3 – Schematic diagram of experimental set up used for the experiment**

All these experiments were carried out under the same conditions of a pumping rate of 1cm/sec, a pressure of 22 MPa per square inch, a temperature of 121 °C, using a single core (SC) of similar permeability obtained from the same well P12.

The existing industry procedures followed the preparation of basic and secondary flooding experiments. Figure 1 shows the schematic diagram of experimental set up used for the experiment.

## 3 Results and discussion

The objectives of the above tests were to determine the effect of water injection and the injection water composition on the dynamic displacement in some real core of the sandstone of the reservoir in question, in the Niger Delta in Nigeria.

### 3.1 Optimization of the injected water composition

To assess the impact of various types of water and their mineralization on recovery and determine the optimal low salinity system, thirteen major secondary flood tests were conducted.

The effect of the injected salinity on the efficiency of displacement of low water salinity flooding was investigated using seawater, SE-W3 at 35091 parts per million, and two field injection waters, namely SE-W1 at 260324 ppm, SE-W2 at 160183 ppm and formation water SE-W3 at 224888ppm. The used waters were diluted to half of their original salinity, 5000 and 2000 parts per million and used in oil displacement in selected core samples. The results of this set of experiments have shown that a salinity of 5000 ppm is the optimal system for a reservoir candidate.

SE-W2 original water and its optimal water were then used as high and low water salinity in core flood experiments. The displacement coefficient was evaluated under different flooding regimes.

The results of flooding of these series of experiments are presented in the form of oil recovery of percentage initial oil in place (OOIP) compared to the type of brine, as shown in Fig. 4.

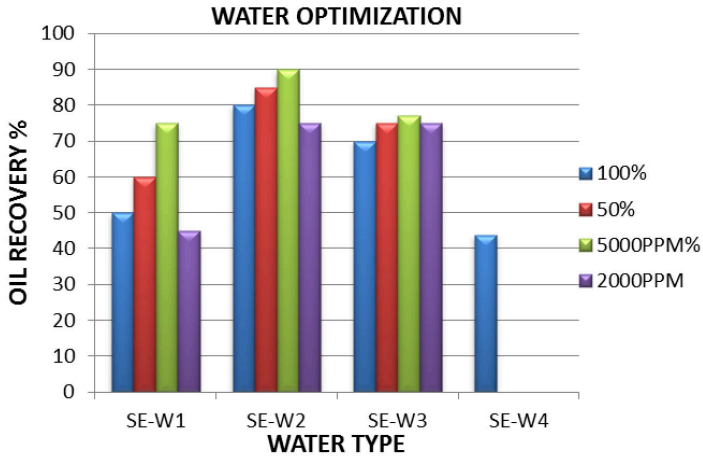



**Figure 4 – Effect of water composition on oil recovery**

Figure 4 shows that the highest oil recovery of 88.2 % of OOIP was obtained with 5000 ppm dilution. The reservoir water produced the lowest oil recovery of 41.6 % of OOIP. Reducing the salinity of SE-W2 water below 5000 ppm did not improve the efficiency of the displacement process, but resulted in a reduction in total oil recovery. The results also showed that the salinity of parts per million 5000 seems to be the optimum mineralization for all used waters in this study. Thus, SE-W2, (5000 ppm) will be referred to as low water salinity, SE-W1 (260.324 ppm) as the average salinity of water and SE-W3 (35,000 ppm) – high salinity of water in this evaluation.

The result of a second set of experiment aimed at assessing the impact of varying concentrations of NaCl brines, and Formation Water on oil recovery is shown in Table 4.

**Table 4 – Different brine concentrations used in the experiment**

| Run No. | Type of Brine | PPM | Porosity, % | Connate water saturation % | Pore volume, cc | Secondary recovery % OOIP @ 3PV |
|---|---|---|---|---|---|---|
| 1 | RO | 4 | 24,54 | 20,11 | 79,8 | 69,94 |
| 2 | NaCl | 500 | 24,42 | 8,72 | 80,2 | 71,33 |
| 3 | NaCl | 1000 | 24,47 | 7,80 | 80,1 | 72,68 |
| 4 | NaCl | 1500 | 24,37 | 15,85 | 80,3 | 77,22 |
| 5 | NaCl | 2000 | 24.42 | 9,88 | 80,33 | 76,78 |
| 6 | NaCl | 2500 | 24,81 | 9,11 | 79,6 | 76,51 |
| 7 | NaCl | 5000 | 24.21 | 9,55 | 80,1 | 65,65 |
| 8 | NaCl | 50000 | 24,65 | 9,46 | 79,75 | 69,11 |
| 9 | Formation | 24887 | 24,66 | 9,25 | 80,0 | 76,96 |
| 10 | Diluted FW | 1500 | 24,06 | 12,01 | 77,0 | 74,98 |

The recovery of the percentage curves at the end of 3 pore volumes (PV) with various NaCl brines, RO, FW and diluted Formation Water is shown in Figure 5. An interesting trend is observed with decreased concentration of NaCl brine from 5000 to 1500 ppm, secondary oil production at the end of 3 PV increases from 65.65 % to 77.22 %, indicating a recovery growth of 11.57 %, although there is a 2 % – 8 % of OOIP by [11]. A decrease in recovery is noticed from 77.22 % to 71.33 % with a further decrease in the NaCl brine concentration from 1500 ppm to 500 ppm. This trend reveals the optimum concentration of NaCl ions, which alters the wettability state from oil-wet to water-wet state.

Recovery with formation water of 224,88 PPM is higher than any brine, with the exception of 1500 PPM of optimal concentration indicating that it is the presence of various salt ions in the formation water, which actually helps make the core samples more water-wet than NaCl alone. RO water also worked

well in brining recovery at 3 PV of about 69.94 %, but that is only 0.53 % higher than 50,000 parts per million but smaller than other brines used in this study. A high recovery of about 76.96 % observed by the injection of formation brine, 24887 PPM in the core sample, where the connate water is also of the same quality is actually 19.21 % higher than the recovery seen by [16].

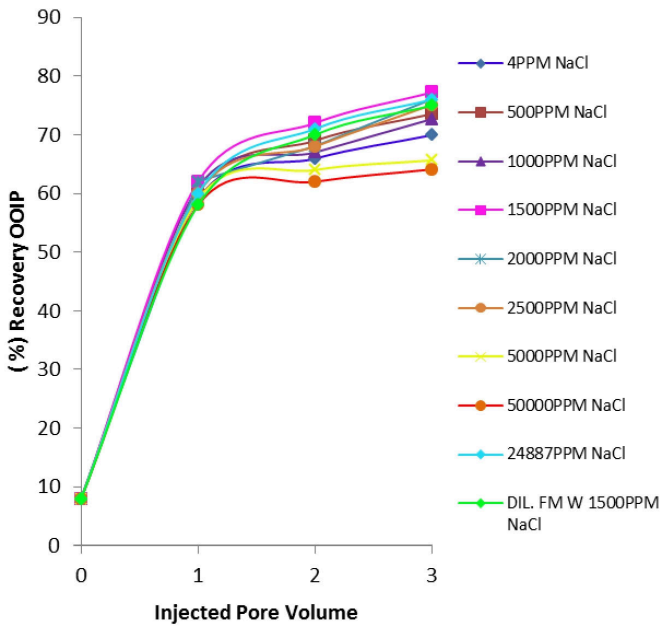


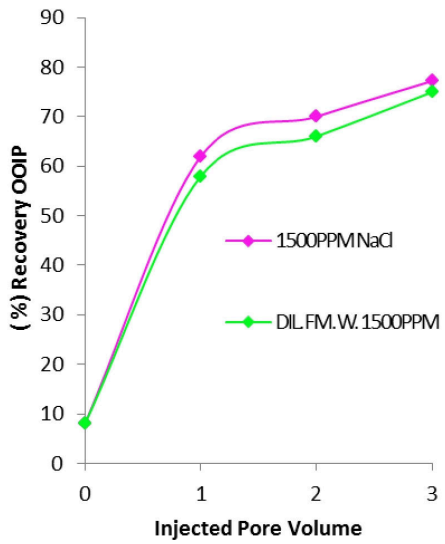

**Figure 5 – Percentage Oil Recovery at the end of 3 PV injections of different concentrations of NaCl Brines**

### 3.2 Comparison of 1500 PPM NaCl Brine with Diluted Formation Water 1500 PPM Brine

Two recovery curves representing recoveries of 1500 ppm NaCl and 1500 ppm formation water are produced in figure 6 to compare overall percentage oil recovery from the two brines. The two recovery curves overlap for the initial part but the % recovery with 1500 NaCl PPM Brine overtakes for the latter region giving the ultimate recovery to be 78.22 % OOIP. Recovery with NaCl brine is 2.24 % higher than the diluted FW brine compared at 3 PV brine injection.

This curve shows the effectiveness of single ion (NaCl) brine over multi-ion composed diluted formation brine. Thus low salinity EOR is also dependent on the constituent of the brine rather than just the total dissolved solid (TDS) of the brine [18].

It was inferred from the curve where the connate water is formation water of 224.888 PPM and injected brine – diluted formation water of 1500 PPM is less effective than 1500 NaCl brine by 2.24 %.




## 4 Conclusions

Based on the results of this work the following conclusions may be drawn:

1. For the studied system, a significant additional oil recovery could be obtained by using low-salinity flooding.

2. The 1500 PPM NaCl brine is the most effective among compared brines for secondary recovery at the 3 PV injection criteria.

3. The effective oil recovery increases upon decreasing NaCl brine salinity from 5000 PPM to 1500 PPM and decreases upon reducing the salinity to 500 PPM.

4. 1500 PPM is the optimum salinity of injection water for enhanced oil recovery in the candidate reservoir of the studied field

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