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A Numerical Study of Tertiary Oil Recovery by Injection of Low-Salinity Water

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Abstract

The injection of Low Salinity Water (LSWI) as an Enhanced Oil Recovery (EOR) method has recently attracted a lot of attention. Extensive research has been conducted to investigate and identify the positive effects of LSWI on oil recovery.

In order to demonstrate the impact of introducing low salinity water into a reservoir, simulations on the ECLIPSE 100 simulator are being done in this work. To simulate an actual reservoir, an easy static model was made. In order to replicate the effects of injecting low salinity water and normal salinity, or seawater, the reservoir is three-phase with oil, gas, and water. It has one injector and one producer.

Five cases were suggested to investigate the effect of low salinity water injection with different concentrations and the period of injection.

The low salinity injection period varied from twenty-five years in case one and reduced five years in each case until reached to five years in final case.

Higher oil recovery factor obtained in case one with injection time twenty-five years and lower recovery factor for case five with injection time of low salinity water injection five years.

Lower water concentration gives higher oil recovery for all cases where this study investigated the effect of low-salinity water flooding as slug injection.

From the five cases presented, field oil recovery factor (FOE), field oil production rate (FOPR), field oil production total (FOPT), field pressure (FP), and field water cut (FWCT) were observed. Oil recovery is 56.6 percent in high salinity water flooding (HSWF), and 71.8 percent

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in low salinity water flooding (LSWF) for 0 percent salt concentration and 62.40 percent for 20 percent salt concentration as in case one.

Keywords: secondary oil recovery, low salinity injection, tertiary oil recovery, recovery factor.

1. Introduction

Energy demand has increased by multiple orders of magnitude in the modern age, with global energy demand anticipated to raise to 40% by 2035 [1]. Emerging economies, particularly China and India, fuel the majority of this demand [1]. There are a variety of energy sources accessible, but oil and gas is the most popular. Renewable energy is a new source of energy whose supply is predicted to treble by 2035 [2].

This, however, will not be enough to supply the world's whole energy need. As a result, oil and gas, generally known as fossil fuels, will remain the primary energy source in the future, meeting at least half of global energy consumption in [1].

Low salinity water injection is a new oil recovery technique that has been demonstrated to boost oil recovery by 8% to 12% on secondary recovery in sandstone reservoirs. Water injection is the most extensively used pressure-maintenance technology in the world. Because seawater is the most frequently available type of water near oil platforms, injecting seawater into the reservoir is the most common secondary injection [3].

Since [4], who noted an increase in oil recovery by low salinity water injection into a sandstone core due to the presence of clay, several studies have been undertaken on the technique.

The studies [5], [6] highlighted the effect of crude-oil/brine/rock (COBR) interaction and the importance of all these components in low salinity waterflooding. Their research found that not only the composition of reservoir water (or initial water saturation or connate water), but also the composition or salinity of injected water, had an impact on oil recovery.

Adsorption from crude oil, the presence of potentially mobile particles, and initial water saturations were all necessary circumstances for low salinity waterflooding to have a favorable effect [7], [8]. And experiments backed up fines migration idea [8], [9].

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Fines migration causes a reduction in permeability and pressure drop, which results to an increase in oil recovery, according to [9-12] investigated the impact of MIE (Microscopic Ionic Exchange). [13], [14] Investigated the effects of low salinity water on clay particles and wettability.

The effects of crude oil compositions on low salinity water flooding. The ionic composition of injected water and the crude oil composition are both critical for the retention of polar oil components and hence influence wettability variations. [15]

The CMG-GEM commercial simulator to investigate how tailored water injection can improve oil recovery from carbonate rocks. Temperature, mineralogy, oil type, and initial rock wettability all affect the efficiency of tailored water injection. [16]

In the previous two decades, traditional oil recovery has been ineffective, leaving more than 65 percent of the original oil in place unrecoverable. Enhanced oil recovery (EOR) procedures are thus necessary to recover a significant amount of this unrecoverable oil.

Low salinity/smart waterflooding EOR technology has lately garnered considerable attention in the oil industry to increase oil recovery factor from sandstone and carbonate reservoirs. The impact of low salinity waterflooding was reported initially by [17] utilizing sandstone sediment cores, he comparing a syringe of seawater to that of freshwater, noting that oil recovery increased higher following the injection of freshwater.

To provide an integrated modeling assisted history matching and field size LSW production forecasting, [18] used GOCAD, CMGGEM, and CMOST for geological modeling, simulation, and integrated modeling, respectively. They discovered that the geological parameters of the reservoir have an impact on the performance of low salinity water.

[18] built a mechanistic model using the Computer Modeling Group's GEM program to evaluate the potential application of LSWF to increase oil output. The suggested model demonstrated that geological clay has a significant impact on field size during the LSWF process in the secondary and tertiary phases. The study found a wide range of recovery factors ranging from 19 to 40%, implying that geological variables such as facies features, clay distribution, and percentage had a

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significant impact on LSWF performance. It was also discovered that wettability alteration had the greatest impact on oil recovery, accounting for 58 percent to 73 percent of total output.

The characteristics of simulation studies on LSWF conducted over the last ten years suggest the need for developing a reservoir model to simulate a more systematic performance and optimization of the LSWF process at field scale, as previous models developed were focused more on simulating the mechanism than sensitivity analysis. As a result, for a more successful field application, LSWF must be evaluated using an appropriate reservoir model.

The ECLIPSE 100 Black Oil Simulation will be used to carry out this study. Numerous simulation situations will be tried and recorded. There will be three phases and live oil in a straightforward static model. These are the goals of this work:

1. To investigate how changing the salinity of the water affects oil recovery. Plots illustrating the oil recovery against time and salinity variations are displayed on various plots.

2. To suggest the optimal water salinity for the injection process. This is suggested using a reservoir numerical simulation. Recovery versus. Salinity graphs are displayed.

2. Methodology

The influence of low-salinity water injection (LWSI) was investigated using a software model and a basic black oil reservoir.

The description of the reservoir given in Table (1), where a basic corner plot grid of 15 x 15 x 3 (X, Y, Z) is constructed to represent the field project. The number of grids is kept to a bare minimum so that simulation runs take as little time as possible and are as simple as possible.

PVT data uses a live oil and dry gas. The PVT properties of the oil shown in Table (2). Figure (1) shows the two wells located at the edges of the reservoir.

The properties porosity and permeability has been taken as the average values in the described model.

The two wells have been proposed to be horizontal and located at the position (i=15, j=15) for the produced and (i=1, j=1) for the injector at a depth of 2700m.the rate of injection and production are set to be the same (100 m3/day). The simulation started from 1 January 1990 for twenty-five years (until 2015). low salinity water flooding has been simulated as enhanced oil recovery (EOR) with high salinity /seawater (SW) where it was supposed 30 ppm. The results of executing the mentioned files on a Software black oil simulator were examined and described in the terminology. The oil recovery factor (FOE) for the base case (HSWF) was 56.6%.

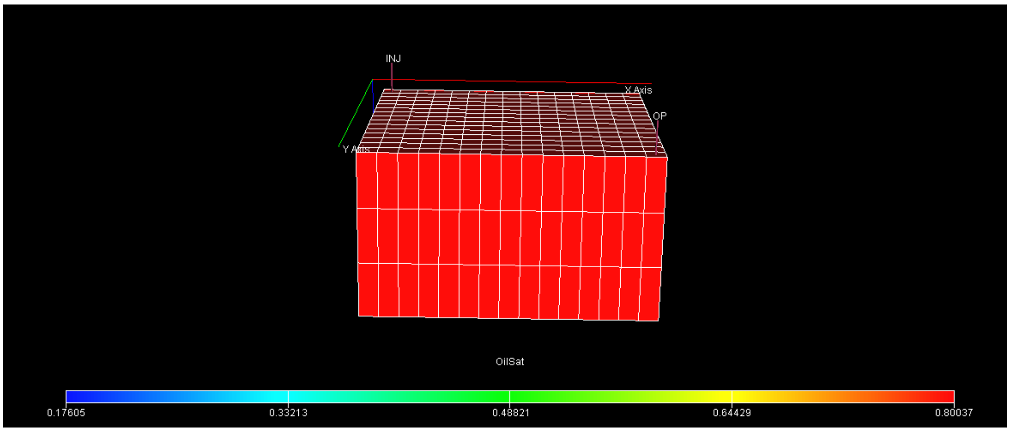

Fig. (1): Flow Viz description of reservoir

The keyword LOWSALT in the RUNSPEC section activates the brine tracking option to track the salinity of the reservoir water and the injected water. PVT properties set in the keyword PVTWSALT to match with concentrations of salt. To specify the use of salinity curves as either low or high salinity water is injected, use the keyword LSALTFNC. High- and low-salinity rock regions are denoted in the REGIONS section by the keywords SATNUM and LWSLTNUM, respectively.

Table (1) The description of the reservoir

Grid dimensions	15, 15, 3
The distance between grids	10 m
Average Porosity	25%
Horizontal Permeability (XX, YY)	250 mD
Vertical Permeability (ZZ)	25 mD
Rock compressibility	4.6E-5

Table (2) Equilibrium data properties.

Datum depth	2680 m

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The pressure at datum depth	270 bars
Oil-water contact (WOC)	2680 m
The depth of Gas-Oil contact (GOC)	2000 m

Table (3) The properties of Dead oil.

Water, kg/m3	1000
Oil, Kg/m3	850
Gas, Kg/m3	1.2

Table (4) Fluid densities (kg/m3)

Pressure (bars)	Formation volume factor (FVF) (rm3/sm3)	Visc (cp)
200	1	0.47
280	0.999	0.47
300	0.998	0.47

3. Results and Discussion

The goal of this research is to find the ideal time to inject low-saline brine into the reservoir for the most efficient oil displacement procedure. The LSWF method was implemented 5, 10, 15, and 20 years after traditional high salinity secondary waterflooding to replicate its effect on oil recovery factor, based on the base case of low saline brine injection immediately after primary production.

3.1. Case I.

Low and High Salinity Water Injection as a Secondary and Tertiary Recovery Method Simulations were run with LSWI and HSWI first separately assuming that the field has not gone through waterflooding before. LSWI was performed as secondary recovery method and then HSWI was also performed as secondary recovery method. After that, both types of injection were also run in tertiary mode.

In Case I, water flooding begins concurrently with the start of oil production at the same rate (100 sm3/day). This secondary flooding occurs over a twenty-five-year period using high-salinity water with a salt content of 30ppm; Comparison with low salinity water flooding (LSWF) for twenty-five years having 0 ppm, 5 ppm, 10 ppm and 20 ppm.

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The observed results for this case shown in Table (5).

As the salt concentration lowers, field oil efficiency, or field oil recovery (FOE), improves. Figure (2) shows the trends in oil recovery at various salinities, with the best recovery of 71.8% at a 0 percent saline concentration. When concentrations are reduced, the field water cut (FWCT) is shown to decrease (as illustrated in Figure (3)).

The field oil rate shown in Figure (4) was observed to increase when the concentration is reduced. The total field production (FOPT) shown in Figure (5) was observed to decrease with increase the concentrations.

The field pressure as shown in Figure (6) was observed little drop about 3 PSIA the difference between 0% saline concentration and 20% saline concentration.

In terms of salinity, the recovery from LSWI is 37.2 percent higher than the recovery from High Salinity Water Injection (HSWI); both are secondary recovery methods. When HSWI is performed alone or before LSWI, there is an earlier water cut, owing to the more efficient waterflooding with low salinity water alone.

Table (5) The observed results for Case I

Run number	Concentration percenate,%	Time (year)	Recovery factor (FOE),%	FOPT (SM3)
1	0% salt con.	25	71.8	97015.367
2	5% salt con.	25	70.15	94778.539
3	10% salt con.	25	66.6	90013.492
4	20% salt con.	25	62.4	84314.492
5	HSWF (30% salt con.)	25	56.6	61208.781

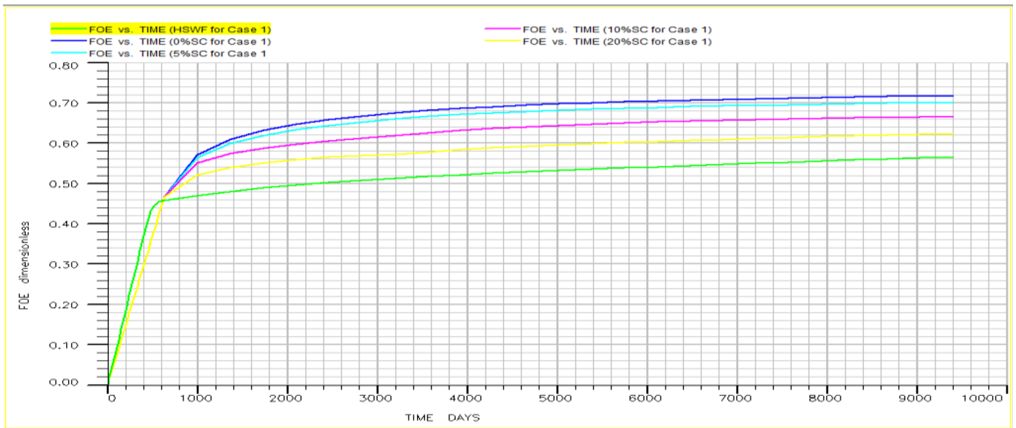

Fig. (2): Field Oil Recovery (FOE)

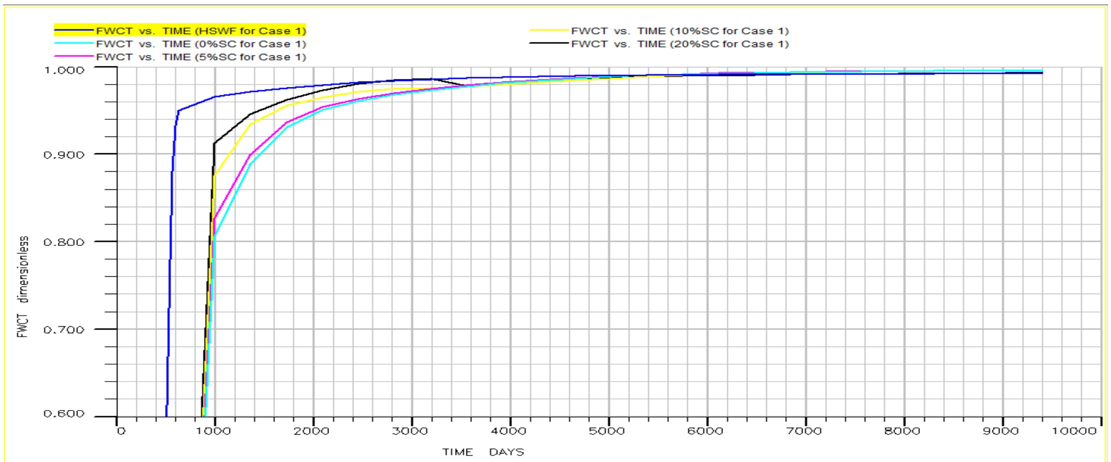

Fig. (3): Water cut (FWCT)

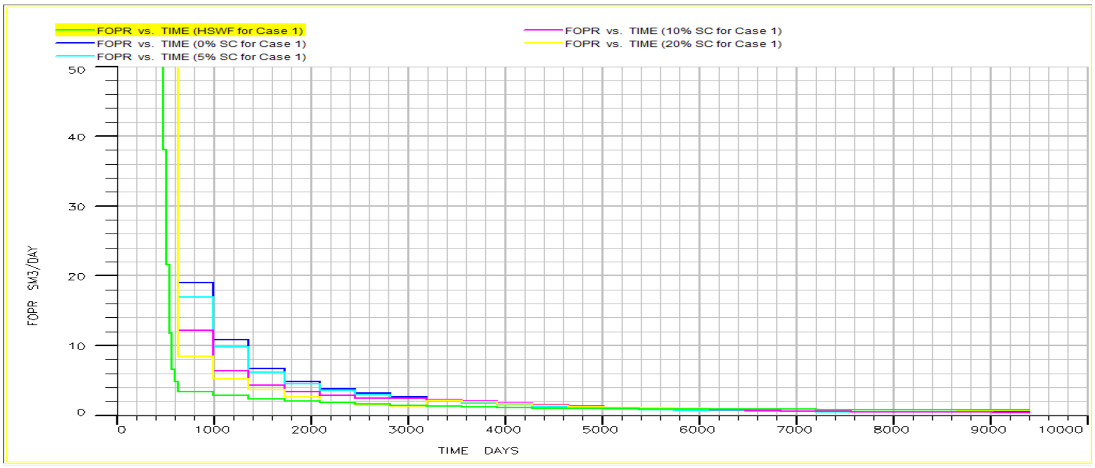

Fig. (4): Field Oil Production Rate (FOPR)

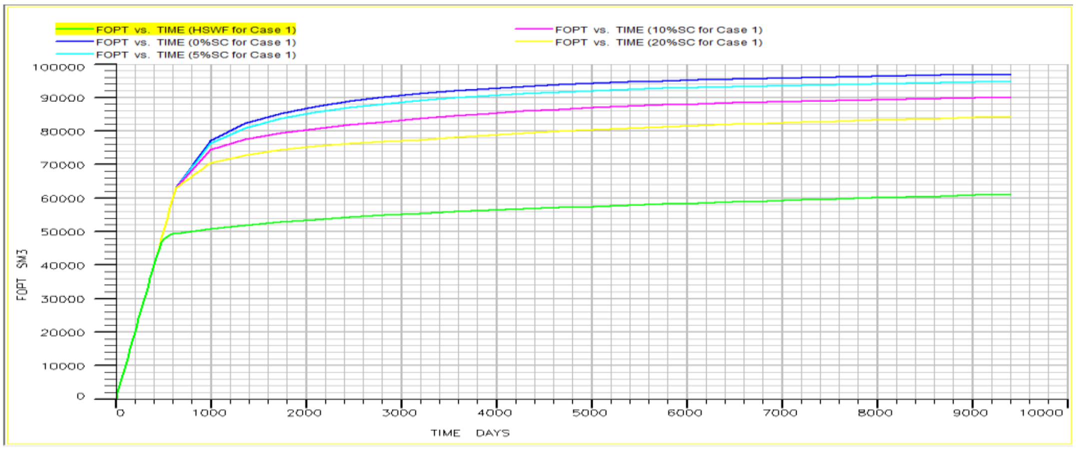

Fig. (5): Field Oil Production Total (FOPT)

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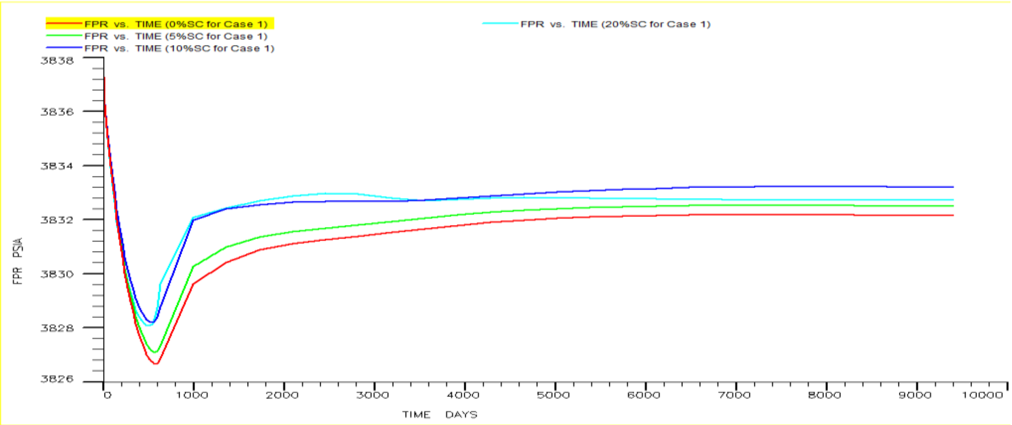

Fig. (6): Field Pressure (FP)

3.2. Case II.

The scenario in Case II included the initial injection of high-salinity water at 30ppm from the start of water production through the conclusion of the field's production life cycle, followed by flooding with low-salinity water (i.e., 20 years of low-salinity water flooding). As with Case I, the initial volumetric flow rate between the producer and injector well was 100 sm3/day. At the conclusion of the first five years, the oil recovery (Figure (7)) rose as the salt content decreased.

The oil production rate and oil recovery increase as the saline content reduces after flooding with fresh water containing 0 ppm, 2 ppm, 5 ppm, 10 ppm, and 20 ppm of salt concentration (Figures (7) and (8)), and the observed results are provided in Table (6). As shown in Figure (9), the trend in water cuts shows that the lower the salt concentration, the smaller the water cuts. The significant reduction seen is due to a fall in the relative permeability of water because of the wettability shift associated with low-salinity water flooding. The production rates described in Figure (8) show a steady drastic decline from 100 sm3/day to as low as 5 sm3/day. The field oil production total (FOPT) and field pressure shown in Figures (10) and (11)

Table (6) The observed results for Case II

Run number	Concentration percenate,%	Time (year)	Recovery factor (FOE),%	FOPT (SM3)
1	0% salt con.	20	71.14	96120.484
2	5% salt con.	20	69.58	94020.539
3	10% salt con.	20	66.4	88338.086
4	20% salt con.	20	61.08	82526.438

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Fig. (7): Field Oil Recovery (FOE)

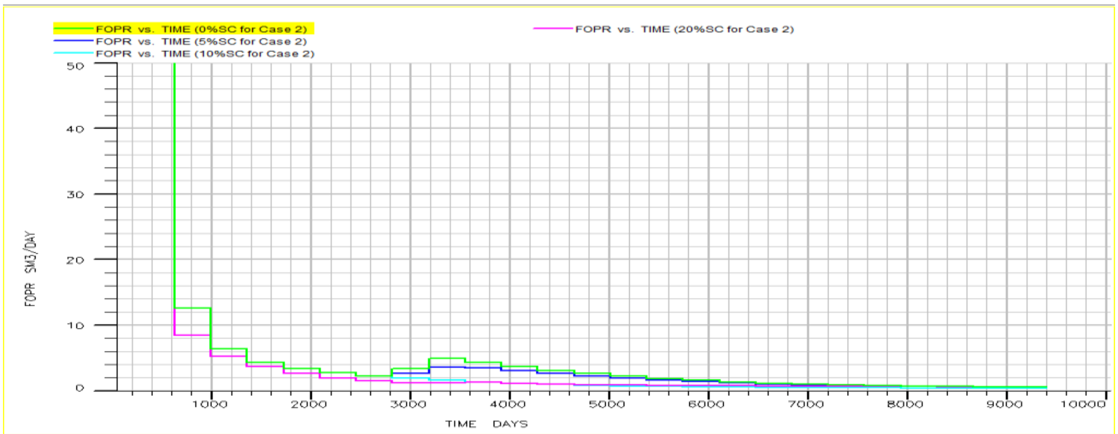

Fig. (8): Field Oil production rate (FOPR)

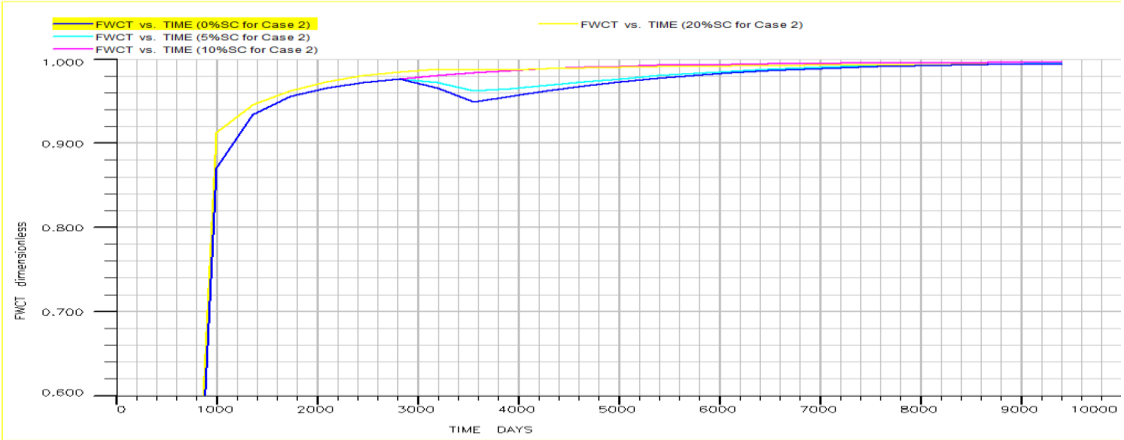

Fig. (9): Water cut (FWCT)

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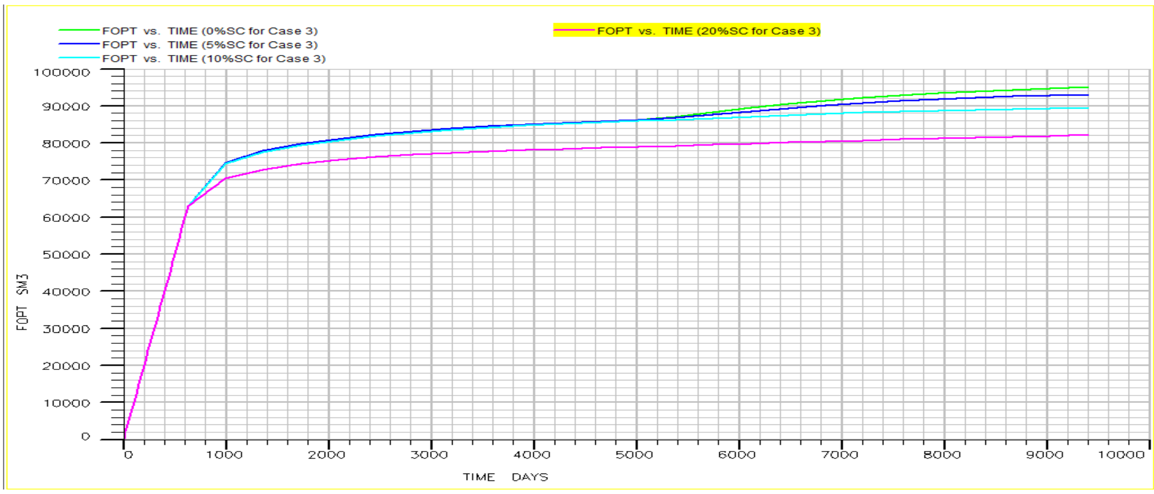

Fig. (10): Field oil production total (FOPT)

Fig. (11): Field Pressure (FP)

3.3. Case III.

After 15 years of secondary HSWF with the same brine content, LSWF was done. Figure 4 shows the outcome of the tertiary LSWF oil production rate forecast (a). Compared to the secondary HSWF baseline, tertiary LSWF had a greater production rate during the predicted period. This illustrates that using LSWF during tertiary oil recovery can boost an oil reservoir's production capability.

The scenario in Case II included the initial injection of high-salinity water at 30ppm from the start of water production until the end of the field's product lifecycle, followed by low-salinity water flooding until the field's production life cycle ended (i.e., fifteen years of low-salinity water flooding). The Field oil recovery (FOE) shown in Figure (12) was observed 70.34% for 0%SC.

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The FOE as in Figure (12) increased with a reduction of salt concentration at the end of the first ten years.

Field water cut (FWCT), Field oil production Rate (FOPR), field oil production total (FOPT),field pressure (FPR) results are observed in Table (7) and the Figures (13) to (16) respectively.

Table (7) The observed results for Case III

Run number	Concentration percenate,%	Time (year)	Recovery factor (FOE),%	FOPT (SM3)
1	0% salt con.	15	70.34	95035.25
2	5% salt con.	15	68.9	93128.719
3	10% salt con.	15	66.31	89594.047
4	20% salt con.	15	60.84	82201.07

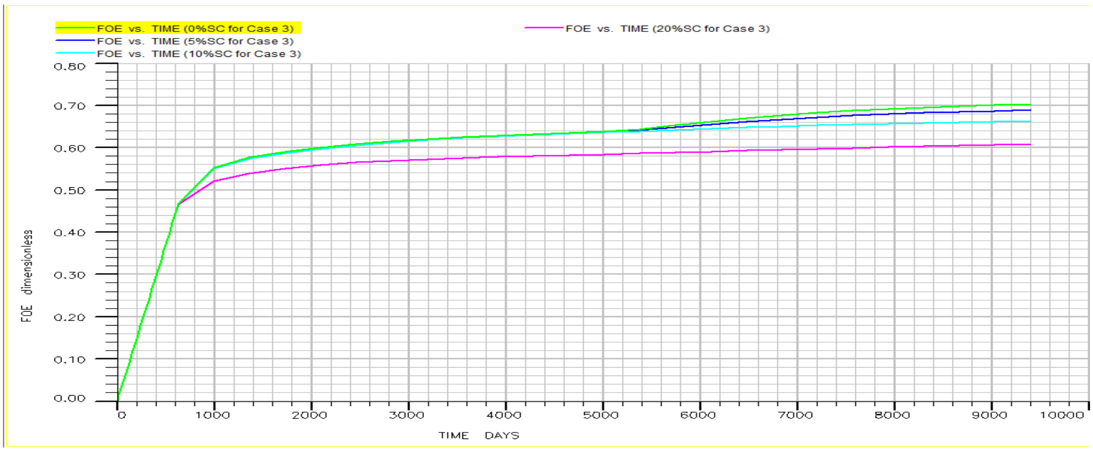

Fig. (12): Field Oil recovery (FOE)

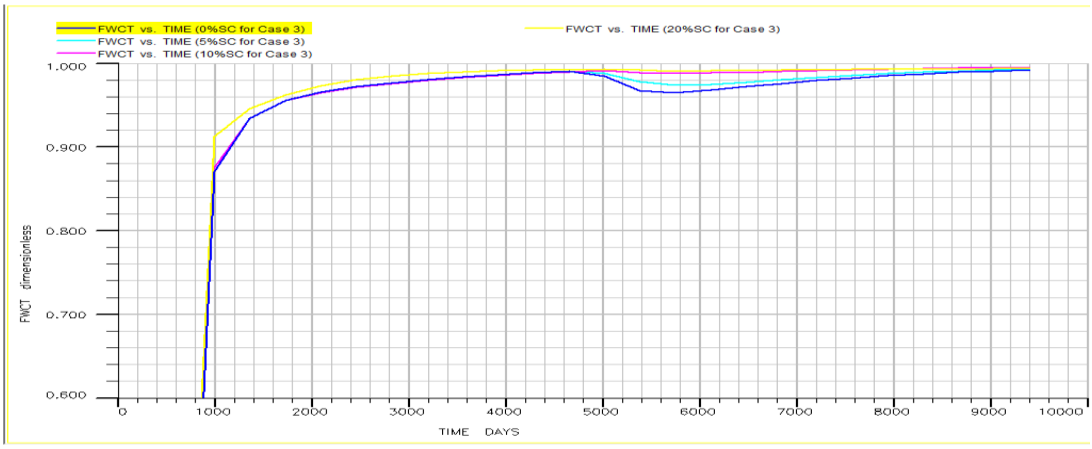

Fig. (13): Field Water cut (FWCT)

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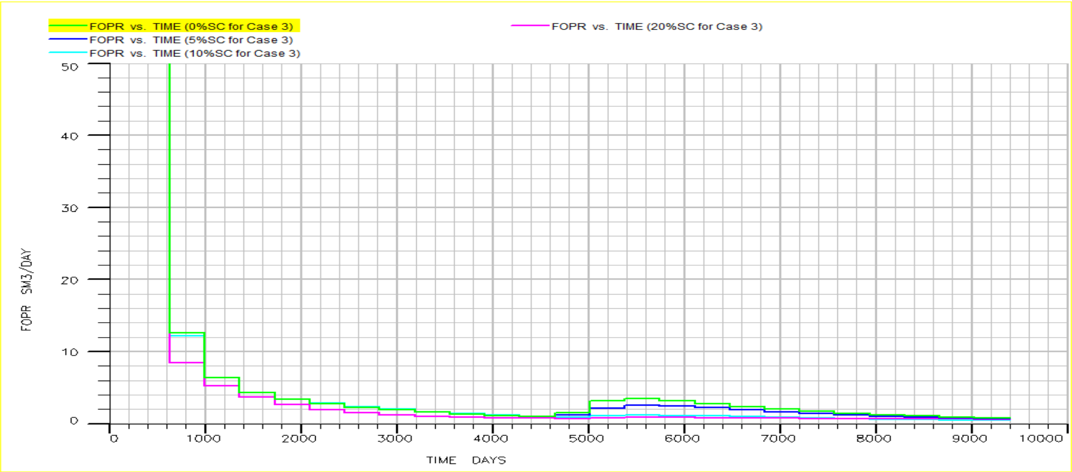

Fig. (14): Field Oil production rate (FOPR)

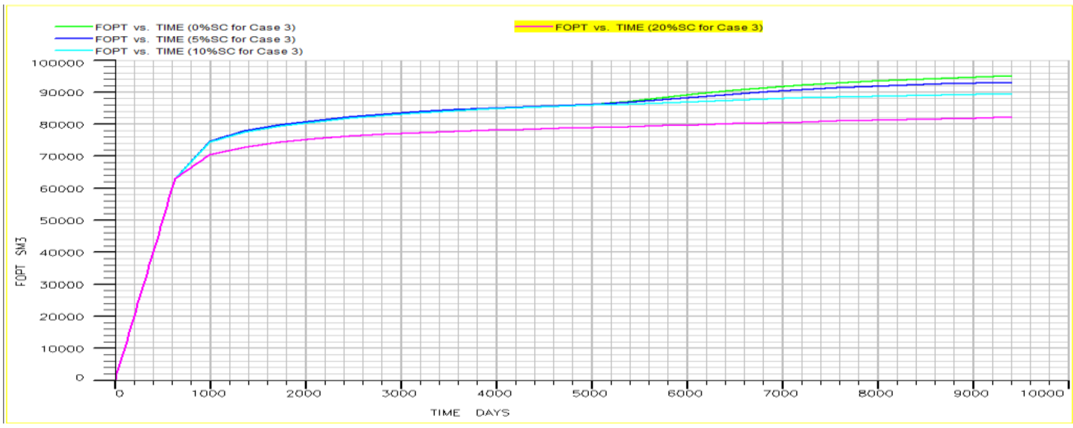

Fig. (15): Field Oil Production Total (FOPT)

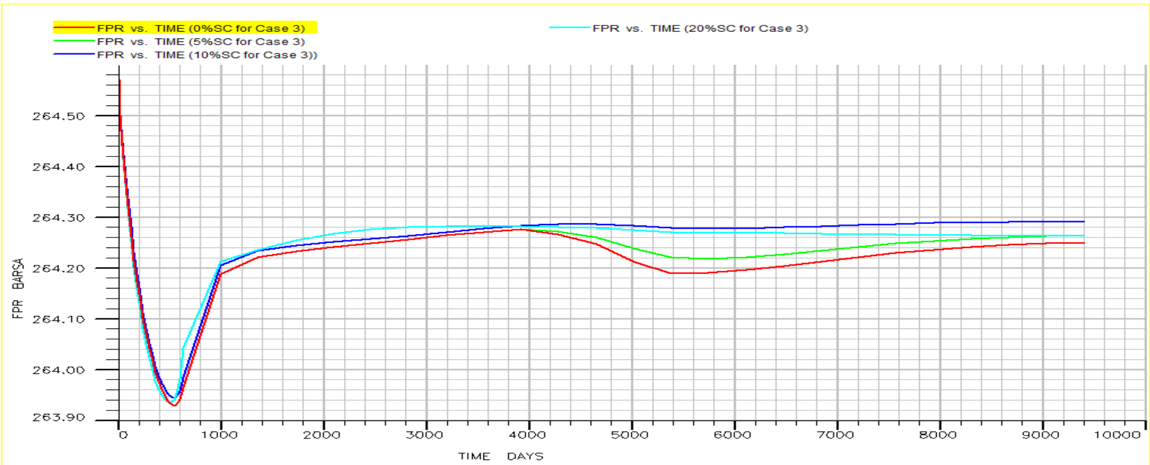

Fig. (16): Field Pressure (FP)

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3.4. Case IV.

The initial injection of 30ppm high-salinity water from the start of water production until fifteen years later was followed by low-salinity water flooding until the end of the field production life cycle in Case IV (i.e., ten years of low-salinity water flooding).

The FOE as in Figure (17) increased with a reduction of salt concentration at the end of the first ten years

Field water cut (FWCT), field oil production (FOPR), field oil production total (FOPT), field pressure (FPR) results are observed in Table (8) and the Figures (18) to (21) respectively.

Table (8) The observed results for Case IV

Run number	Concentration percenate,%	Time (year)	Recovery factor (FOE),%	FOPT (SM3)
1	0% salt con.	10	68.97	93191.477
2	5% salt con.	10	67.87	91706.523
3	10% salt con.	10	65.93	89089.273
4	20% salt con.	10	60.64	81932.453

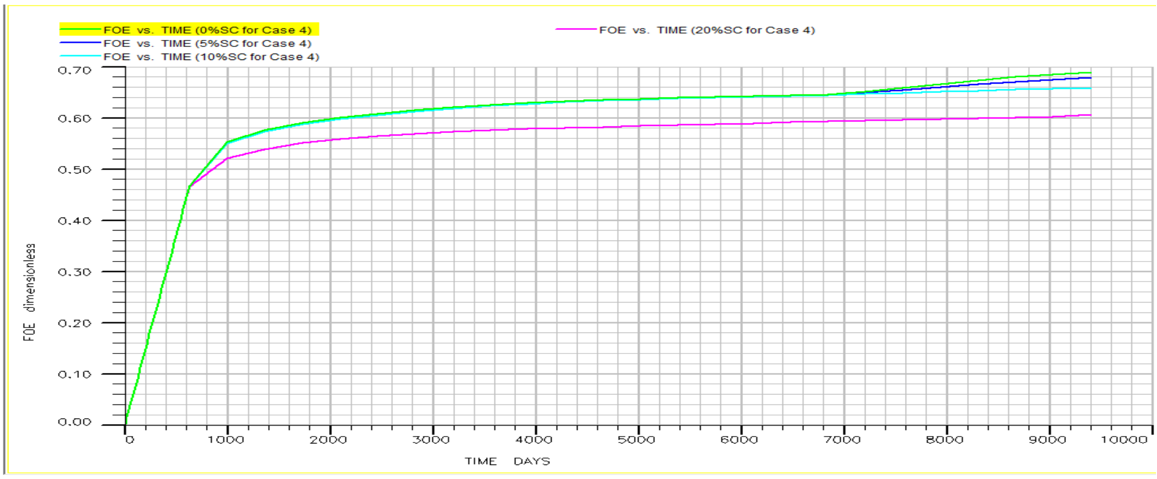

Fig. (17): Field Oil recovery (FOE)

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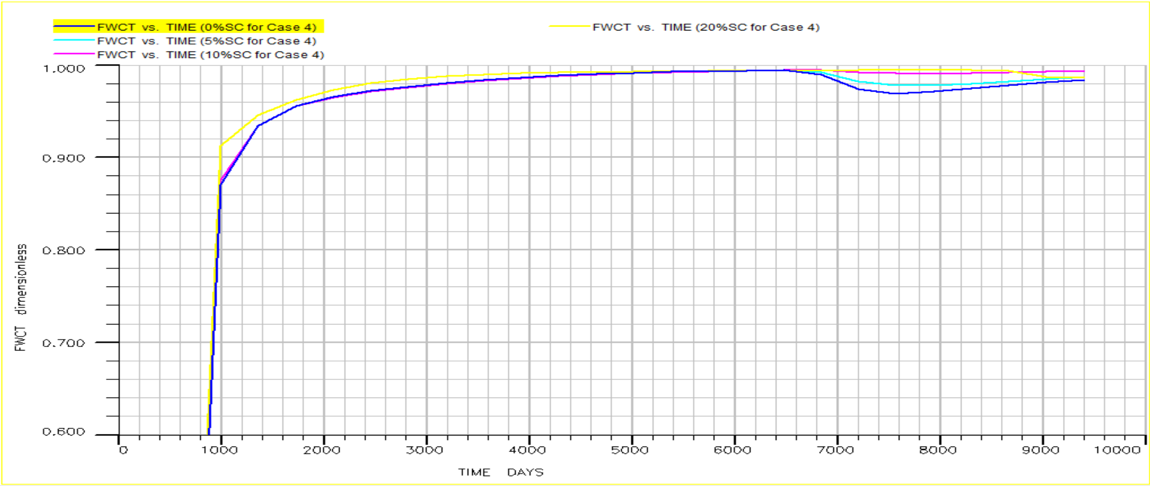

Fig. (18): Field Water cut (FWCT)

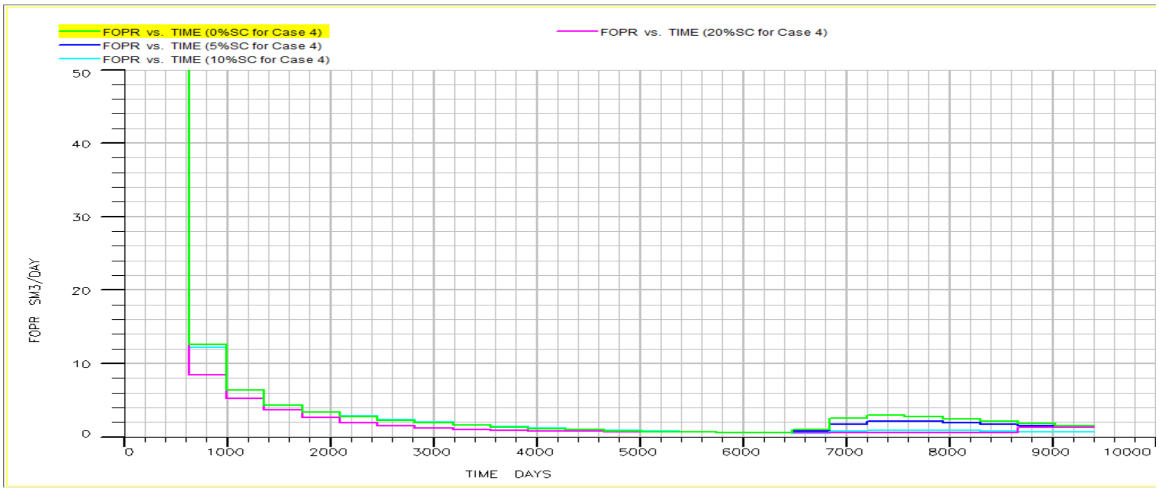

Fig. (19): Field Oil production rate (FOPR)

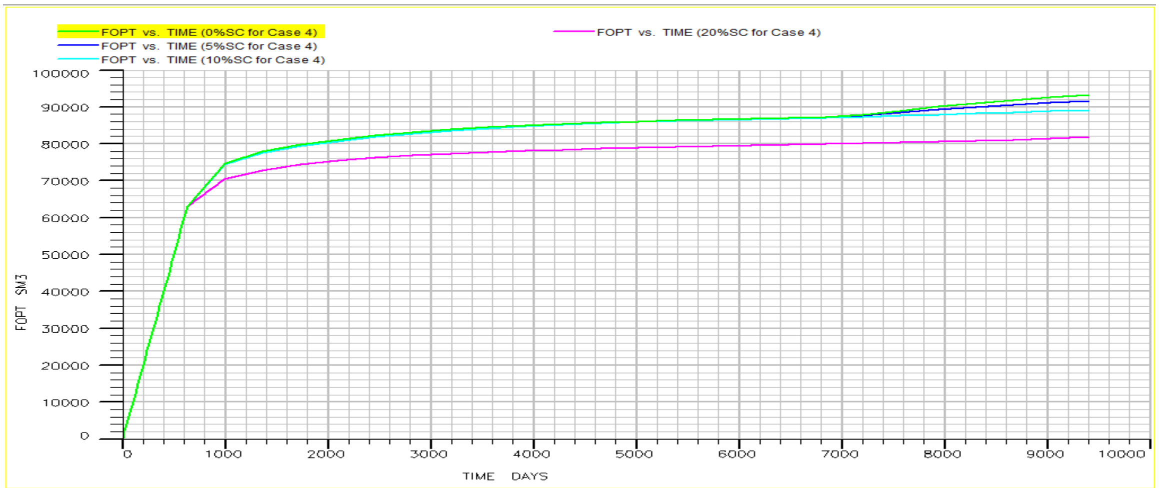

Fig. (20): Field Oil Production Total (FOPT)

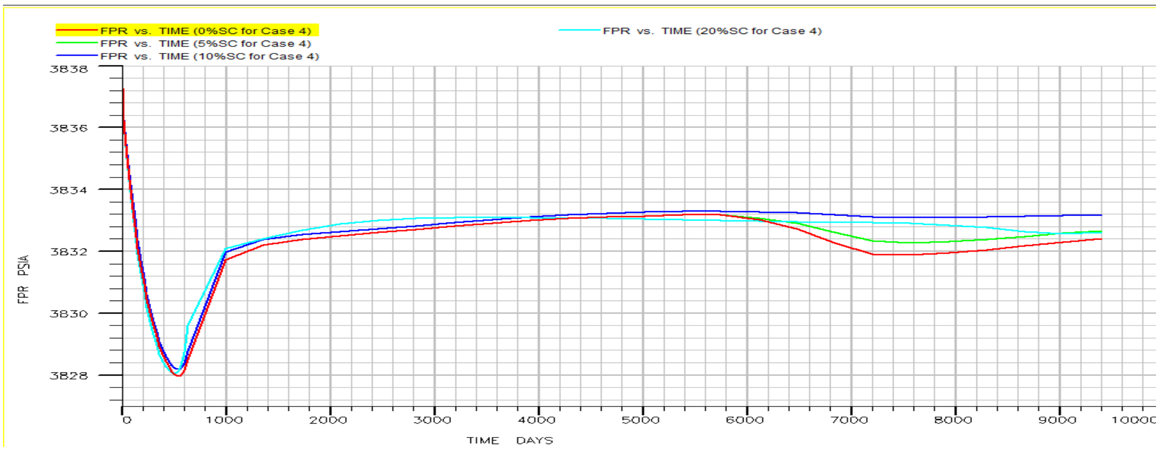

Fig. (21): Field Pressure (FP)

3.5. Case V. The condition in Case V included the initial injection of high-salinity water of 30ppm from the start of water production until fifteen years later, followed by low-salinity water flooding until the conclusion of the field production life cycle (i.e., ten years of low-salinity water flooding). At the conclusion of the first 10 years, the FOE rose with a decrease in salt content, as seen in Figure (22), Table (9) and Figures (23) to (26) show the results of field water cut (FWCT), field oil production (FOPR), field oil production total (FOPT), and field pressure (FPR).

Table (9) The observed results for Case V

Run number	Concentration percenate,%	Time (year)	Recovery factor (FOE),%	FOPT (SM3)
1	0% salt con.	5	66.31	89590.258
2	5% salt con.	5	65.95	89114.414
3	10% salt con.	5	65.39	88347.672
4	20% salt con.	5	60.32	81503.133

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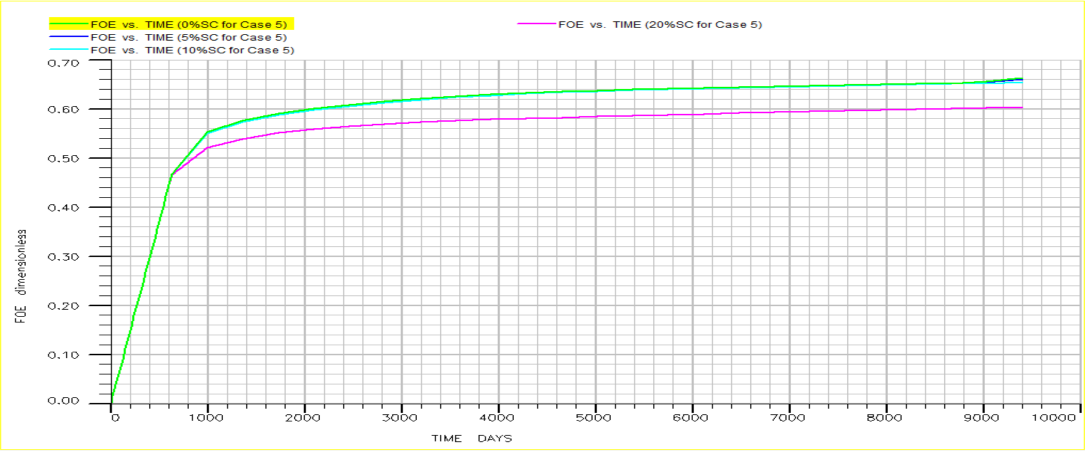

Fig. (22): Field Oil recovery (FOE)

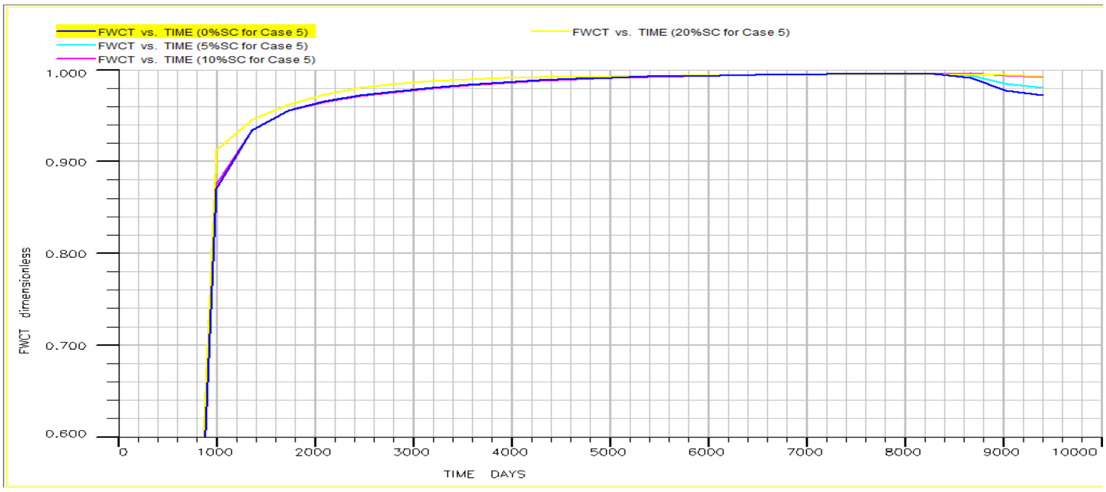

Fig. (23): Field Water cut (FWCT)

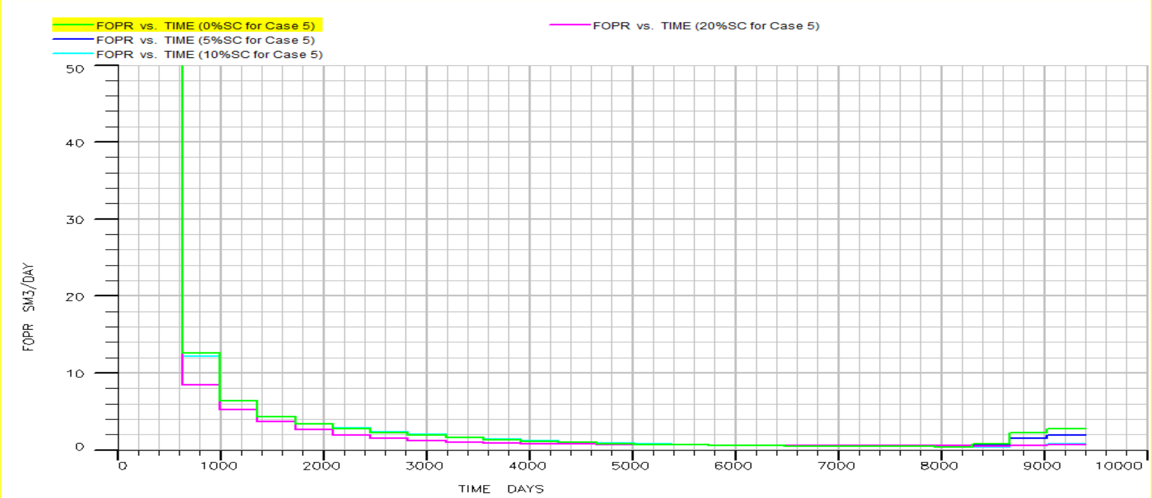

Fig. (24): Field Oil production rate (FOPR)

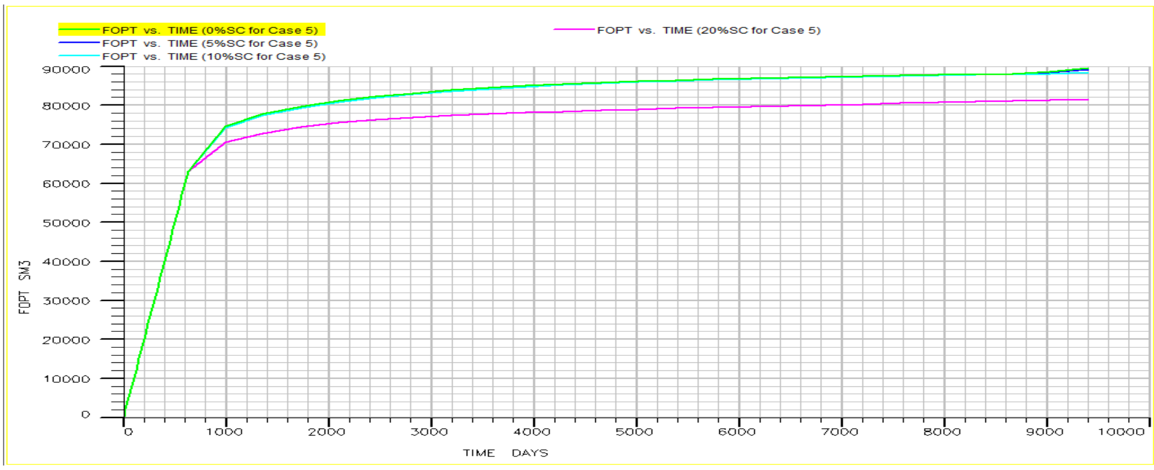

Fig. (25): Field oil production total (FOPT)

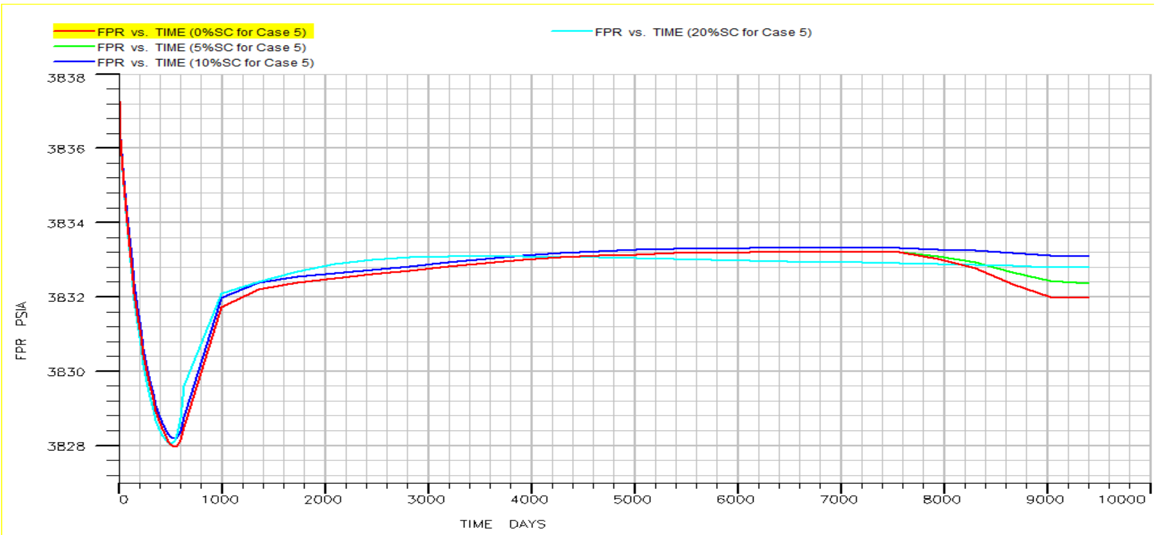

Fig. (26): Field Pressure (FP)

3.4. Response of Tertiary Low Salinity Waterflooding

To learn more about tertiary recovery using LSWF, a sensitivity analysis of injection durations following secondary seawater flooding was carried out for 5, 10, and 15 years, with a simulation prediction produced until 2030. Figure (27) compares different injection periods of brine with low salinity for 0 percent Salt Concentration and for the other concentrations as in Figures (28) to (30) and showed that the secondary LSWF yields the highest oil recovery while subsequent injections of LSW yields less additional oil recovery.

This is because reservoirs may induce low-resistance water channels during oil production, skipping future injected water [19]. In the meantime, high-salinity brine injection compresses the

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ionic double layer and increases clay-to-clay attraction, causing the oil layer to be strongly adhered to the rock surface [20], [21]. demonstrated that when an electric double layer is formed at the formation/LSW interface, the ions in the HSW generate some ion aggregates. These clumps remained within the brine Nano layer. The Nano-layer brine separates the oil film from the carbonate surface and acts as anchors to keep oil components near the substrate.

When the injected brine is extremely dilute or the ions chemical equilibrium is disrupted, the benefits of using tertiary LSWF may have a significant impact on rock wettability. Furthermore, one of the most significant needs is the injection time of water. When compared to the second or third stage of LSWF, LSW is more effective when used in the initial stage of secondary recovery.

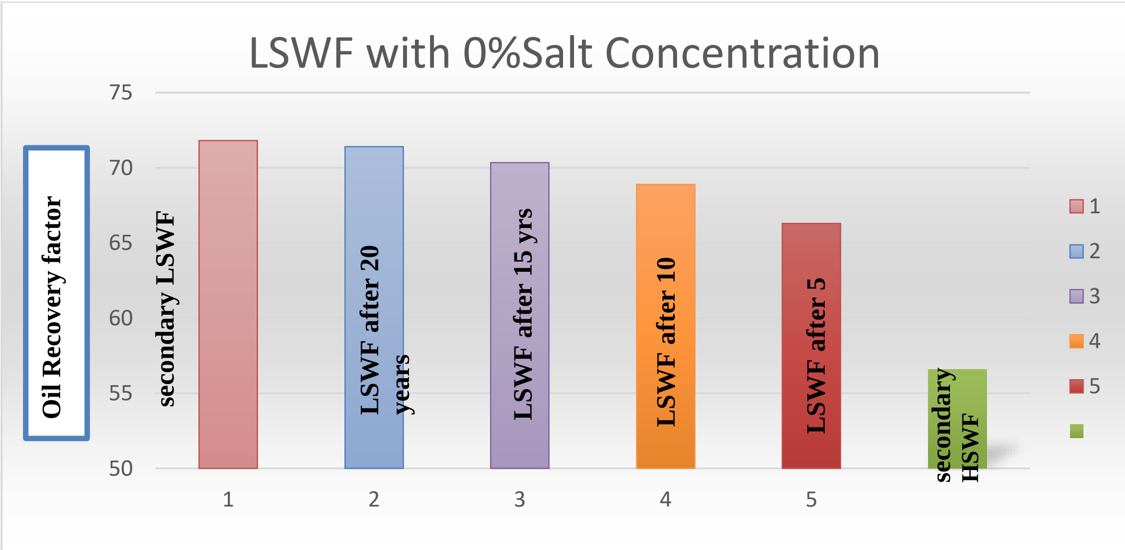

Fig. (27): Comparison of the oil recovery factor after different LSW injection Periods for 0%Salt Concentration

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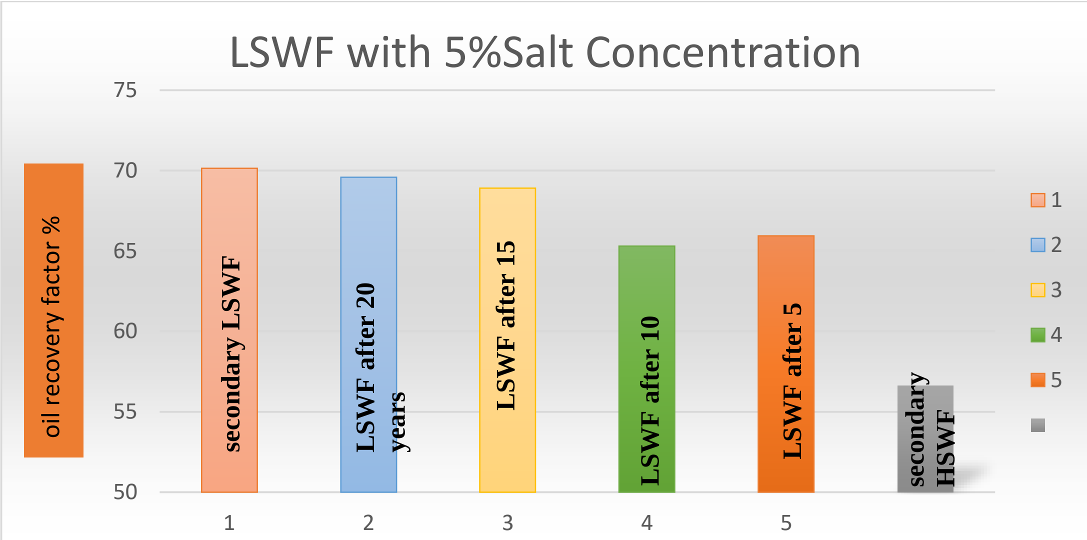

Fig. (28): Comparison of the oil recovery factor after different LSW injection Periods for 5%Salt Concentration

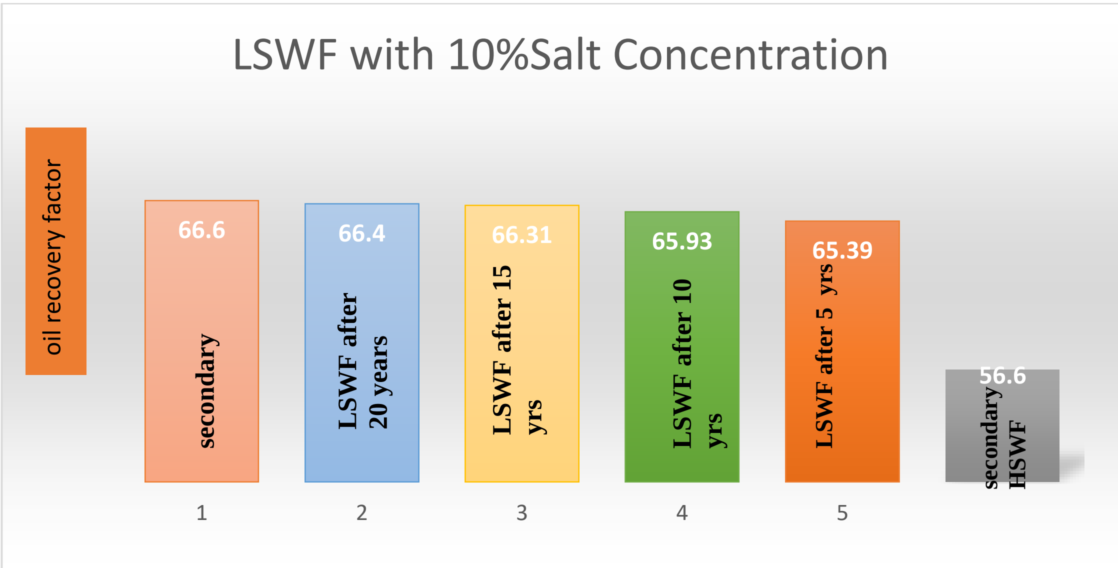

Fig. (29): Comparison of the oil recovery factor after different LSW injection Periods for 10% Salt Concentration

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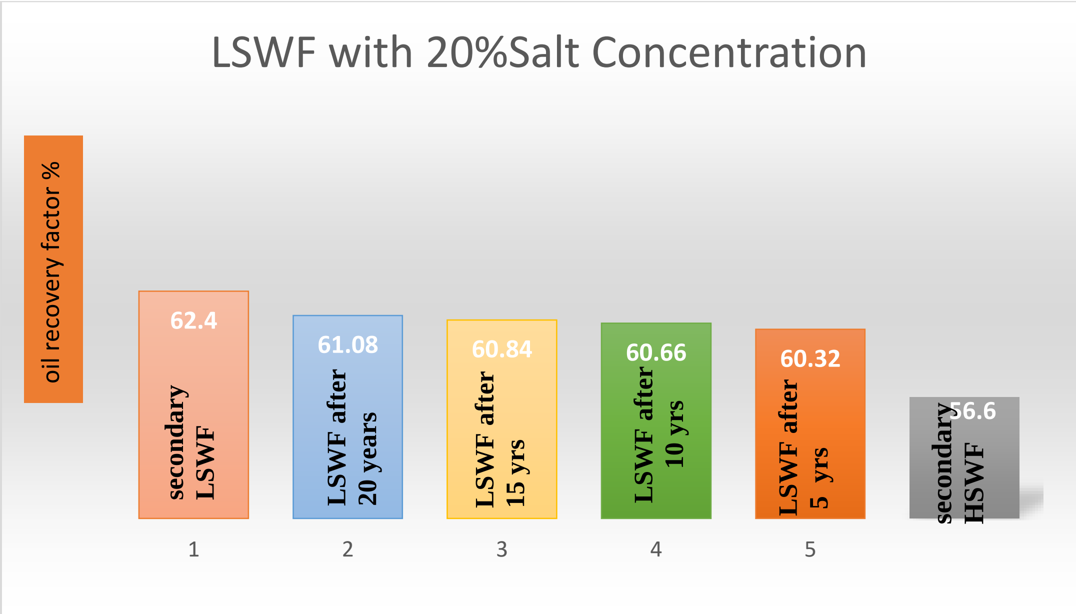

Fig. (30): Comparison of the oil recovery factor after different LSW injection Periods for 20% Salt Concentration

4. Conclusion

Positive effects of LSWI appears to happen when used as a secondary recovery method in comparison with tertiary mode, however, in tertiary mode the recovery gain can still be attractive in some cases.

It was deduced that the earlier the injection of low-salinity brine as soon as a decline in oil rate is observed, the higher the oil recovery would be where the oil recovery in HSWF as a secondary recovery was 56.6% while in low salinity water flooding (LSWF) as a secondary recovery for 20%Salt Concentration 62.4%.

As shown in the several case situations examined, low-salinity water flooding is an efficient improved oil recovery technique. Injection methods may be advantageous for marginal field operators seeking a simple and inexpensive means of improved recovery. The observed case scenarios demonstrate that at very low saline concentrations, oil recovery may reach 71.8%, 71.14%, 70.34%, 68.9%, and 66.31%, respectively, as shown in Cases 1, 2, 3, 4, and 5.

Although the findings achieved in this research are perfect, they do not take into account other physical variables. To get the best outcomes, physical factors such as fines migration may plug pore throats and cause swelling of clay fines. I would suggest that prior to adopting low-salinity water flooding in the field, studies on core plugs should be conducted and then upgraded to field size models before determining that low-salinity water flooding is advantageous to the field.

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