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Department of Geology

Enhanced Oil Recovery through Chemical Flooding with Low Salinity Water: A Numerical Simulation Study

Bachelor thesis

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Fulltime study

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Enhanced Oil Recovery through Chemical Flooding with Low Salinity Water: A Numerical Simulation Study

Anotace:

Tato studie zkoumá účinnost zaplavení vodou s nízkou slaností v kombinaci s různými metodami chemického zesíleného získávání ropy (EOR) prostřednictvím simulace. Cílem je vyhodnotit a porovnat účinnost těchto technik při zlepšování těžby ropy, zpomalování průniku vody a snižování množství vody. Studované scénáře zahrnují zaplavení vodou s vysokou slaností jako základní případ, zaplavení vodou s nízkou salinitou a její kombinaci s alkalickým, povrchově aktivním činidlem, polymerem a ASP (alkalický povrchově aktivní polymer). Klíčová zjištění naznačují, že zaplavení ASP s nízkou salinitou překonává všechny ostatní případy a dosahuje nejvyššího výtěžku ropy 72 %, prodloužené plošiny těžby ropy a zpožděného průniku vody na 15 měsíců. Samotné zaplavení vodou s nízkou slaností poskytlo významné zlepšení s 63% regenerací oleje, ale nedosahovalo kombinace ASP. Jiné kombinace, jako je nízká slanost s alkálií nebo povrchově aktivní látkou, vykazovaly mírná zlepšení, zatímco nízká slanost s polymerem poskytla výsledky srovnatelné se základním případem. Tato zjištění zdůrazňují důležitost přizpůsobení chemických strategií EOR podmínkám v nádrži pro optimální těžbu ropy a výkonnost výroby.

Klíčová slova: Chemický EOR; zaplavení vodou s nízkou slaností; Zlepšená regenerace ropy; Simulace nádrže

Počet stran: 46

Počet příloh: 1

Annotation:

This study investigates the performance of low-salinity water flooding combined with various chemical enhanced oil recovery (EOR) methods through simulation. The goal is to evaluate and compare the effectiveness of these techniques in improving oil recovery, delaying water breakthrough, and reducing water cut. The scenarios studied include high-salinity water flooding as the base case, low-salinity water flooding, and its combination with alkaline, surfactant, polymer, and ASP (alkaline-surfactant-polymer). Key findings indicate that low-salinity ASP flooding outperforms all other cases, achieving the highest oil recovery of 72%, a prolonged plateau of oil production, and delayed water breakthrough to 15 months. Low-salinity water flooding alone provided significant improvement with a 63% oil recovery but fell short of the ASP combination. Other combinations, such as low salinity with alkaline or surfactant, showed moderate improvements, while low salinity with polymer yielded results comparable to the base case. These findings highlight the importance of tailoring chemical EOR strategies to reservoir conditions for optimal oil recovery and production performance.

Keywords: Chemical EOR; Low salinity water flooding; Enhanced oil recovery; Reservoir simulation

Number of pages: 46

Number of annexes: 1

Declaration

I declare that I have prepared the bachelor's thesis myself and that I have stated all the used information resources in the thesis.

In Olomouc, December 15, 2024 ……………………………………………

Rawand Ahmed Younis

Acknowledgment

I extend my sincere gratitude to Associate Professor Dr. Jagar Ali for his exceptional guidance, continuous support, and invaluable advice throughout this journey. His encouragement and expertise have been instrumental in achieving the objectives of this study.

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1. Introduction

Currently, there is a rising worldwide need for energy, but the available reserves in conventional reservoirs are diminishing. Additionally, the rate at which new reserves are being discovered to replace the depleted ones has been progressively decreasing over the past decade (BP, 2011). The significance of enhanced oil recovery (EOR) from existing fields has been increasingly emphasized.

After primary depletion, water flooding was the first and most extensively used enhanced oil recovery (IOR) technique for maintaining pressure. The initial study to demonstrate that a decrease in the salinity of the injection brine increased the oil recovery factor was published in 1959 (Rezaei Doust, 2010). Following this, low salinity water flooding (LSW) was introduced as a new method for enhanced oil recovery. Unlike conventional, higher-salinity water flooding, LSW controls the salinity of the injected water to promote oil recovery. Recoveries from corefloods and single-well chemical tracer experiments with low salinity water can be enhanced by 5–38% compared to basic water flooding. It has been a challenge for many institutions and research groups to determine what are the mechanisms that improve oil recovery during LSW injection (Morrow, N. and Buckley, J., 2011). Several studies have shown that enhancing reservoir wettability to more favorable water-wet is the main mechanism that enhanced oil production during LSW injection (Webb et al. 2005; Jerauld et al. 2008).

Chemical enhanced oil recovery (CEOR) is another type of EOR that has been employed for many decades. Conventional chemical enhanced oil recovery (EOR) methods, such as alkaline, polymer, and surfactant flooding, possess some limitations (Samanta et al., 2012). Polymers have a decrease in viscosity when brines are found in the reservoir or when the temperature increases. In addition, the effectiveness of alkali and surfactants diminishes when they pass through porous materials due to adsorption phenomena (Gbadamosi et al., 2019). Consequently, numerous chemical flooding approaches have been investigated and utilized for enhanced oil recovery. Alkaline-Polymer (AP), Alkaline-Surfactant (AS), Surfactant-Polymer (SP), and Alkaline-Surfactant-Polymer (ASP) are among the options available (Figure 1).

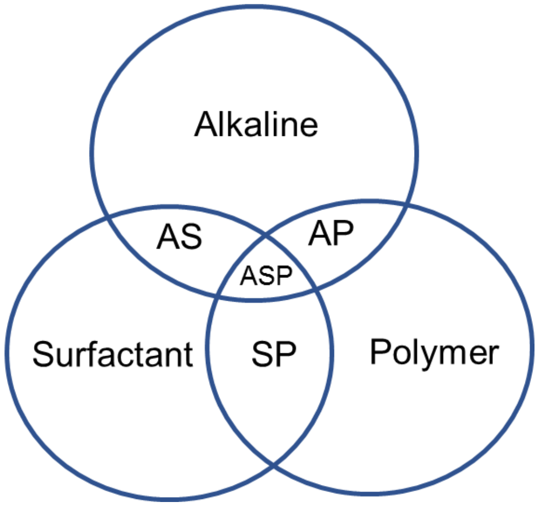

Figure 1. Combination of different chemical enhanced oil recovery (Mohammadi et al., 2012)

The integration of the LSW and CEOR methods is expected to yield additional advantages in enhancing oil recovery (Mohammadi et al., 2012). The objective of this study is to assess the impact of combining chemical flooding techniques with low salinity water on improving oil extraction. The objective will be accomplished through the simulation of a synthetic reservoir model, utilizing precise reservoir parameters and the actual properties of alkaline, surfactant, and polymer.

1.1. Problem statement

Oil recovery using conventional primary and secondary methods often leaves a significant portion of the oil up to 60-70%—trapped in the reservoir due to unfavorable mobility ratios, capillary forces, and rock-fluid interactions. Enhanced Oil Recovery (EOR) techniques, such as chemical flooding, have emerged as potential solutions to address this issue. Among these methods, combining chemical flooding with low salinity water has shown promising results in mobilizing residual oil by altering wettability, reducing interfacial tension, and improving sweep efficiency. However, the effectiveness of such techniques depends on numerous factors, including reservoir conditions, fluid properties, and chemical interactions (Maheshwari, Y.K., 2011)

Despite experimental studies supporting the potential of this approach, there remains a gap in understanding the detailed mechanisms and optimal conditions for implementation, particularly through numerical simulations (Samanta et al., 2012). Accurate simulation studies are essential to evaluate the performance, feasibility, and cost-effectiveness of this method in field applications.

1.2. Aim of Project

The objective of this study is to assess the impact of combining chemical flooding techniques with low salinity water on improving oil extraction

1. The effect of high salinity water flooding on the enhanced recovery.

2. The effect of low salinity water flooding on the enhanced recovery

3. The effect of low salinity water flooding combined with polymer, alkaline, and surfactant on the enhanced recovery

4. The effect of low salinity water flooding combined with ASP on the enhanced recovery

2. Literature review

2.1. Enhance oil recovery

2.1.1. Primary recovery

To understand the reservoir behavior and estimate the future performance better, it is important to know the mechanisms drive, which controls the fluids in the reservoir. Oil reservoir performance is determined by the feature of it is energy, such as the driving mechanism, that is valid for the movement of oil into the wellbore (Figure 2). There are roughly six types of driving mechanisms that supplies the necessary natural energy for oil recovery, such as rock, expansion drive of liquid, the depletion drive, gas cap drive, water drive, the gravity drainage drive and lastly the combination drive (Tarek, 2017).

2.1.2. Secondary Recovery

Secondary oil recovery includes the initiation of energy in a reservoir and that is by the injection of gas or the injection of water underneath pressure in which the gas can be mixed with oil. There are split wells used for production and injection (Ragab and Mansour, 2021). "Pressure maintenance "is the technique that is used. The movement of oil is simulated by the addition of energy that provides extra recovery at high rates (Figure 2). Today, the gas injection is not that much used due to the low displacement of the oil effectiveness and required gas supplies in market. Pressure maintenance due to gas injection is effective that is if the gravity drainage is effective (Teknica, 2001).

2.1.3. Tertiary recovery

When the secondary process had become ineffective, tertiary recovery process was developed instead (Mandal, 2015). Also the tertiary process was also taken into account for the reservoir application, in which secondary recovery technique was not used due to the low recovery potential (Figure 2). The other case is that the tertiary is a misnomer. Nearly all the reservoirs are needed to be started with secondary or tertiary process at the same time with primary production. For this purpose, the enhanced oil recovery was established and it became popular. Any process of recovery that enhances the oil recovery above primary and secondary production is expected to yield. The enhanced oil recovery is divided into four main groups, which are: the miscible flooding process, secondly the chemical flooding process. Thirdly the thermal flooding process and lastly the microbial flooding process (Ragab and Mansour, 2021).

Number one which is miscible flooding process consists of single and multiple contact miscible process. Polymer, micelle polymer and alkaline flooding are thermal process. Hot water, steam drive, steam cycling and situ combustion is a combination of thermal process. Thermal process can be applied in reservoir of heavy crude oils, in which miscible and chemical displacing procedure is used in reservoirs that contains the light type of crude oil. A microorganism is used by microbial process to help in oil recovery (Terry, 2001).

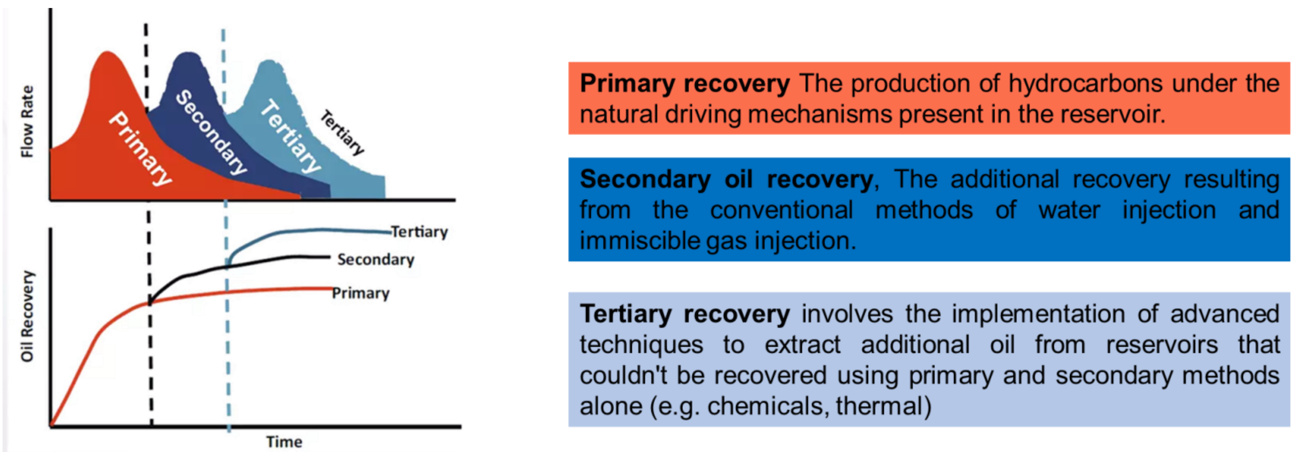

Figure 2. The typical oil production rate and recovery during various stages of a reservoir lifecycle (Pemmadi et al., 2023)

2.2. Chemical enhanced oil recovery

Chemical Enhanced Oil Recovery (Chemical EOR) is a tertiary recovery technique designed to extract additional oil from reservoirs after primary and secondary recovery methods. This method involves injecting specially formulated chemicals into the reservoir to enhance oil displacement efficiency by modifying the physical and chemical interactions between rock, oil, and fluids (Olajire, A.A, 2014). The key mechanisms include reducing interfacial tension (IFT) using surfactants, altering the wettability of the reservoir rock from oil-wet to water-wet, and improving the water-oil mobility ratio through the use of polymers. Additionally, alkaline chemicals can react with crude oil acids to generate in-situ surfactants, further reducing IFT and enhancing oil mobility (Rafa et al., 2016). Common Chemical EOR methods include surfactant flooding, polymer flooding, alkaline flooding, and combinations such as Alkaline-Surfactant-Polymer (ASP) flooding (Figure 3). These methods are particularly effective in mobilizing residual oil trapped in pore spaces due to capillary forces and heterogeneity (Mandal, 2015). While Chemical EOR can recover an additional 10-20% of the original oil in place (OOIP) and is adaptable to various reservoir conditions, it faces challenges such as high costs, chemical adsorption onto rock surfaces, and operational complexities. Its success requires careful reservoir evaluation, optimized chemical formulation, and precise operational management to overcome limitations and maximize recovery.

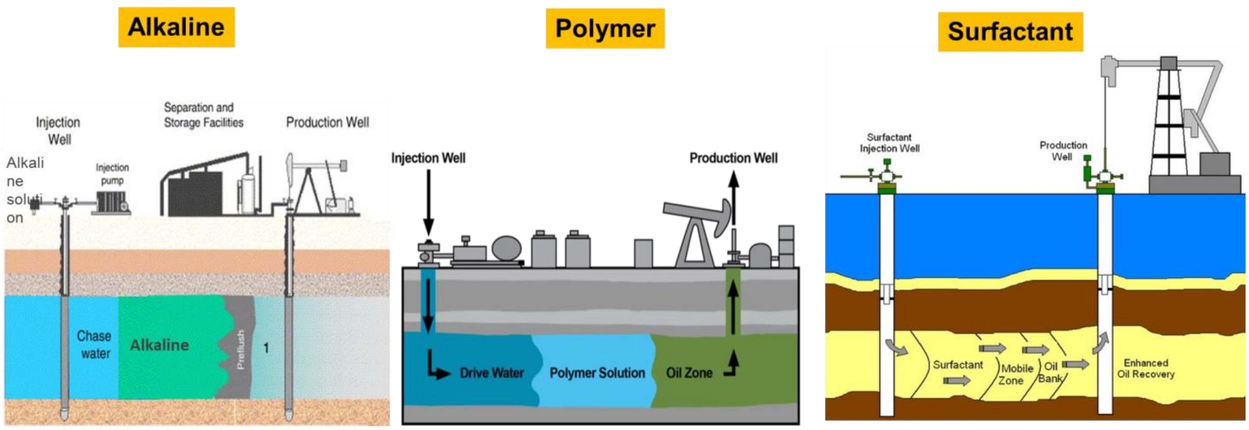

Figure 3. Common Chemical EOR methods include surfactant flooding, polymer flooding and alkaline flooding (Ragab and Mansour, 2021)

2.2.1. Combination of chemical enhanced oil recovery

Different combinations of chemical agents are tailored in CEOR to address specific reservoir challenges and optimize oil recovery. The primary types include Alkaline-Surfactant-Polymer (ASP) flooding, Surfactant-Polymer (SP) flooding, and Alkaline-Polymer (AP) flooding. Each combination leverages the unique properties of its constituents for synergistic effects **(**Olajire**,** 2014).

Alkaline-Surfactant-Polymer (ASP) Flooding is one of the most effective CEOR methods. Alkalis react with acidic components in the oil to generate in-situ surfactants, which reduce interfacial tension. Surfactants further enhance this reduction and aid in oil mobilization, while polymers improve the viscosity of the injected solution, ensuring better sweep efficiency and reduced fingering in heterogeneous reservoirs. This combination is particularly useful in reservoirs with high heterogeneity and complex oil-water interactions. Surfactant-Polymer (SP) Flooding on the other hand, combines surfactants to reduce interfacial tension and polymers to improve the mobility ratio. SP flooding is often employed in reservoirs where alkali interactions may be limited or problematic, such as those with high salinity or carbonate formations. The polymer ensures the surfactant-rich solution reaches the oil-rich zones effectively, resulting in enhanced displacement efficiency. Alkaline-Polymer (AP) Flooding is another combination; alkali is used to generate in-situ surfactants by reacting with crude oil acids, while polymers enhance the viscosity of the solution to improve mobility control (Druetta et al., 2019). AP flooding is cost-effective compared to ASP as it eliminates the need for external surfactants. It is particularly effective in reservoirs with acidic oils and moderate salinity (Figure 4 and 5).

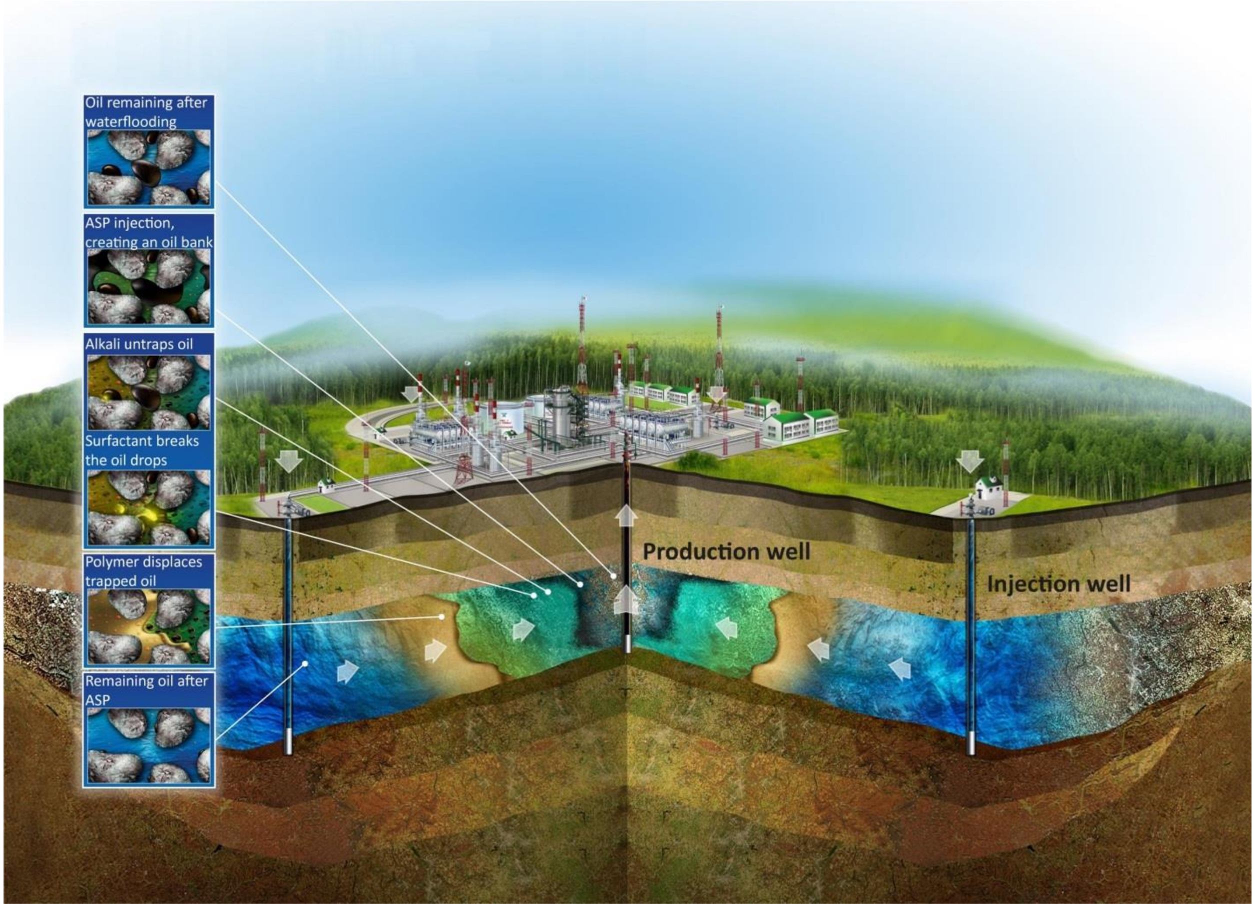

Figure 4. Illustrating the Combination of Chemical EOR Techniques and their Mechanisms (Olajire, 2014)

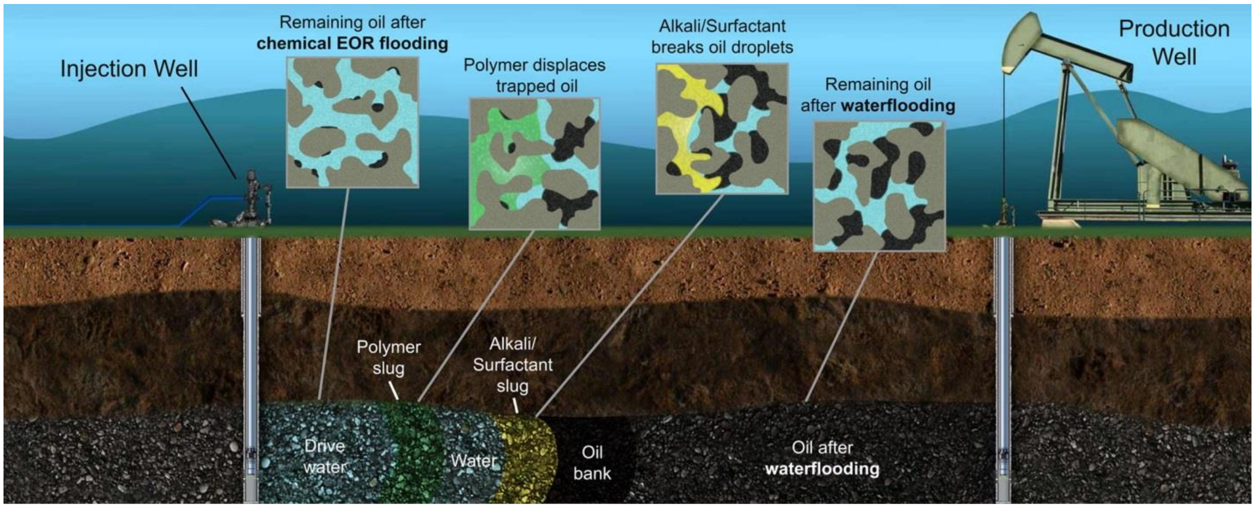

Figure 5. Mechanism of combination of Chemical enhanced oil recovery (Druetta et al., 2019)

2.3. Low salinity water flooding

Low Salinity Water Flooding (LSWF) is an enhanced oil recovery (EOR) technique that involves injecting water with salinity lower than the formation brine into the reservoir. Experiments conducted on both outcrops and reservoir sandstones compared the effectiveness of low salinity water flooding in secondary and tertiary recovery modes. These experiments included both single-phase and two-phase core flooding tests, with continuous monitoring of pressure drop and pH changes. In single-phase flooding, pH values increased from 7.7 to 8.8, and fines production was observed in some cases. Incremental oil recovery was attributed to the reduction in salinity and the rise in pH, particularly in Berea outcrops. However, similar pH increases were not observed in reservoir sandstones. Across various rock types and oil combinations, secondary flooding generally yielded higher oil recovery than tertiary flooding, with incremental recovery from secondary flooding ranging from 6% to 22% (Salehi, Omidvar & Naeimi, 2017).

The performance of low salinity water flooding can be summarized as: (1) Lowering the brine salinity below the initial reservoir salinity significantly enhances oil recovery; (2) A greater reduction in salinity results in a more pronounced pressure drop; and (3) Maximum pH values of around 9 or lower were observed during low salinity water injection. To simulate reservoir conditions, BP conducted core flooding experiments using live oil. In one secondary flooding test, formation water with a salinity of approximately 28,000 ppm was replaced by injected water with a salinity of around 1,400 ppm, increasing recovery from 69.5% to 83.5% of the OOIP. Higher incremental recovery was observed in other secondary floods. For tertiary floods, injecting 1,500 ppm water after a 15,000 ppm secondary water flood improved oil recoveries from 63% to 71% and 75% to 84%, respectively. These studies concluded that for low salinity water flooding to be effective, salinity levels should be reduced to around 4,000 ppm (Sheng, 2014).

2.3.1. Mechanisms of Low salinity Water Flooding

Low Salinity Water Flooding (LSWF) through several mechanisms improves fluid displacement efficiency and mobilizes trapped oil. One of the primary mechanisms is wettability alteration**,** where the injection of low salinity water changes the reservoir rock from oil-wet or mixed-wet to water-wet. This shift enhances the displacement of oil by water, as oil can more easily detach from the rock surface. Another key mechanism is fines mobilization**,** where low salinity water interacts with clay particles or fines in the reservoir rock. These particles detach from the rock surface, exposing previously oil-wet areas that subsequently become water-wet, further facilitating oil recovery (Chai et al., 2022). Low salinity water also reduces the interfacial tension (IFT) between oil and water, enabling the movement of trapped oil droplets through the pore network. Additionally, ion exchange occurs, where divalent cations like calcium ($Ca^{2+)}$ and magnesium (Mg^{2+}) are replaced by monovalent ions like sodium (Na^{+}). This ionic substitution destabilizes the bonds between oil and rock surfaces, freeing the oil for production (Rivet et al., 2010). Another critical mechanism is multicomponent ionic exchange (MIE)**,** which involves the interaction of injected ions with the rock surface, disrupting the adhesion of polar oil components and facilitating oil detachment. Furthermore, low salinity water injection often leads to an increase in pH, which can create an alkalinity effect. This elevated pH can generate in-situ surfactants through the reaction of water and crude oil acids, reducing IFT and aiding in oil mobilization (Figure 4). These combined mechanisms create a synergistic effect, allowing low salinity water flooding to enhance oil recovery by improving both macroscopic and microscopic sweep efficiencies (Al-Saedi and Flori, 2018).

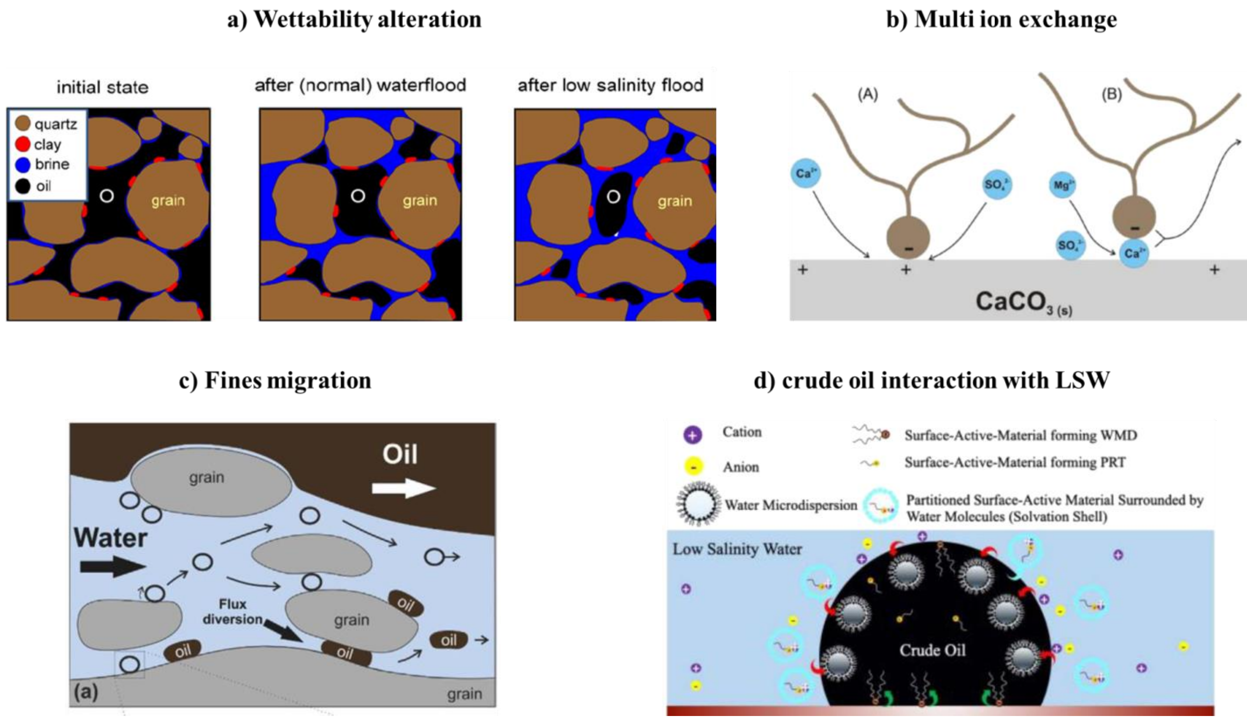

Figure 6. Show the mechanisms of low salinity water flooding (Mehraban et al., 2021)

3. Methodology and modeling approach

In this simulation study, a systematic methodology is followed to evaluate the performance of various chemical flooding techniques, including low salinity water flooding (LSWF) and its combinations with polymer, alkaline, and surfactant (Figure 7). The workflow begins with the base case model, which uses high salinity water flooding, followed by a series of modified cases: Case 1 (LSWF), Case 2 (LSWF + Polymer), Case 3 (LSWF + Alkaline), Case 4 (LSWF + Surfactant), and Case 5 (LSWF + Polymer + Alkaline + Surfactant). The study uses Eclipse 100 reservoir simulation software to model these cases, comparing the results to assess the impact of each flooding method on oil recovery.

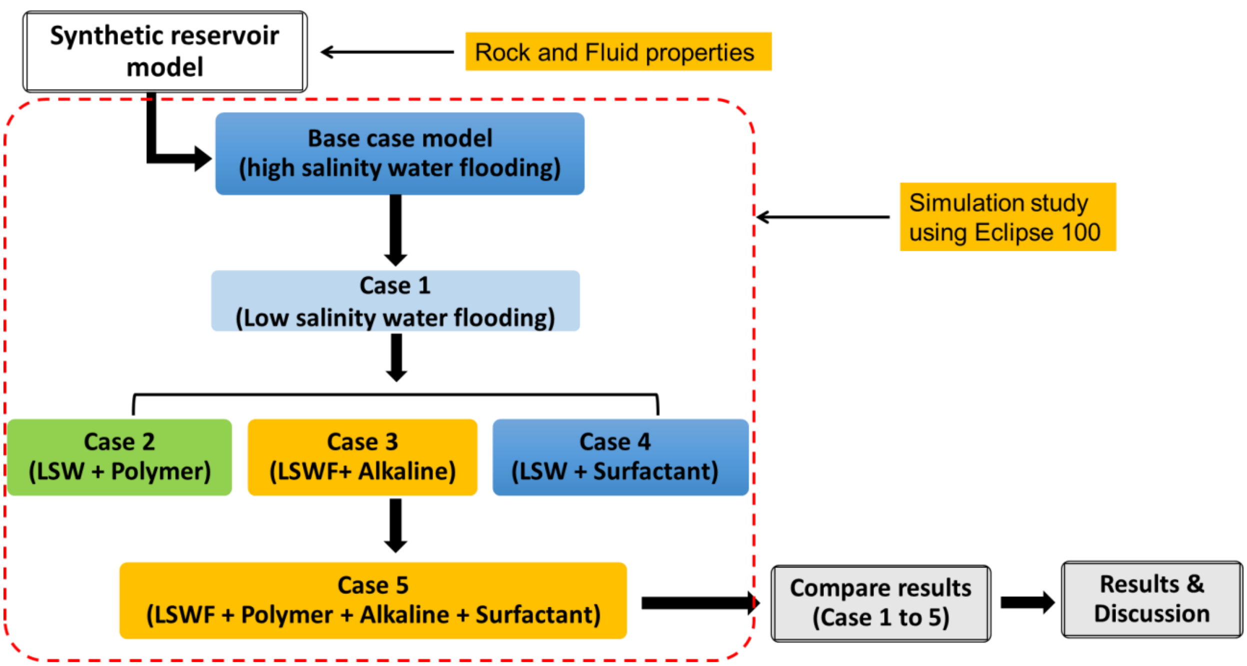

Figure 7. Systematic methodology to evaluate the performance of various chemical flooding techniques

3.1. Model description

A synthetic model has been used as a typical oil reservoir for simulation of low salinity water injection assist with chemical injections. The model is heterogeneous, the permeability range is between 275 to 525 mD and the porosity range is between 0.23 to 0.305 as shown in Figure 8. The initial properties of the model which are used in this project are summarised in table 1.

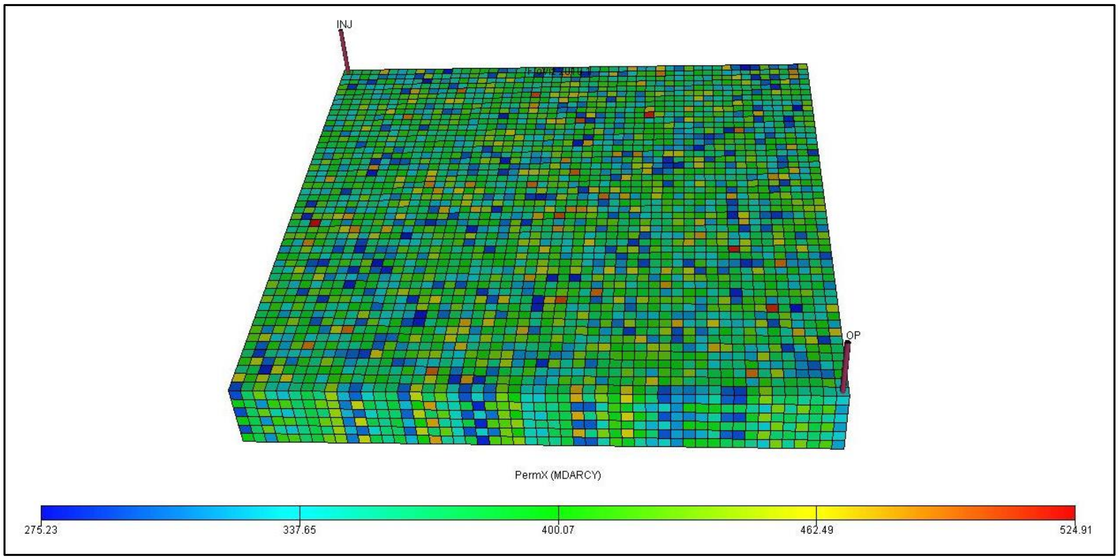

Figure 8. Permeability distribution in synthetic Model

Table 1. Reservoir model properties (Base case)

Parameters	**value**
Reservoir thickness (h), ft	59
Well Radious (r_w), ft	0.5
Porosity	0.23 to 0.305
Permeability, md	275 to 525
Rock compressibility (C_f), psi^{-1}	3.0×10^{-6}
Initial water saturation (S_{Wi})	0.2
Oil density, kg/m^3	850
Water density, kg/m^3	1000
Gas density, kg/m^3	1.2

3.2. Numerical Simulation

Three dimensional simulations were performed using ECLIPSE 100. The synthetic model is discretized by 50×50×6 grids. Each grid measures 3 m x 3 m x 3 m in X, Y and Z directions respectively. Two active wells; a producer and an injector, have been added to the model and they are located diagonally with respect to each other as shown in Figure 8. Both wells are completed from the top to the bottom and they set to be controlled by reservoir fluid volume rate (RESV), with a flow rate of 100 m^3/day.

The active phases in the reservoir model are oil and water. The salinity of connate water was set to be 35 kg/m^3 (TDS), this is approximately the same salinity as for regular sea water. The oil and water viscosities at the initial reservoir pressure of 200 to 300 bars is set to be 2 and 0.5 cp, respectively.

3.2.1. High salinity water injection Model (Base Case)

The base case model involves injecting high-salinity water with a salinity of 40000 ppm, which closely matches the salinity of typical seawater. The model includes two active wells: one injector and one producer, positioned diagonally relative to each other. Both wells operate under reservoir volume (RESV) control. High-salinity water injection is conducted continuously from the start of production until the end, covering a total period of five years or 1,825 days. Details of the base case data file can be found in the Appendix.

3.2.2. Low salinity water injection Model

When LOWSALT keyword is activated, two different sets of relative permeability curves should be assigned with respect to the two different salinities; high and low salinity. A LSALTFNC keyword is used to automatically choose a constant that represents the specific salinity. The value of the weighting factor ranges from 0 to 1 with a constant weighting fraction of "0", indicating high salinity properties to be assigned. A corresponding constant of "1" represents the other extreme of low salinity floods. Interpolation is made for any fractions ranging between 0 and 1, and a weighting factor is used respectively (Table 2). Furthermore, for defining relative permeability curve for high and low salinity water injection, relative permeability profile for high and low salinity were taken from Kossac Chuck, Schlumberger advisor, (Kossac, 2012), (see Figure 9).

Continuous high-salinity water flooding was implemented from the first to the last day of production. Similarly, continuous low-salinity (LS) water flooding, using brine with a salinity of 0.0 ppm, was conducted to compare the overall impact of salinity on oil recovery.

Table 2. LSALTFNC table with weighting factors of F1 and F2 (Kossac, 2012)

Salt Concentration (kg/Sm3)	Salinity (ppm)	F1 factor	F2 factor
0.0	0	1	1*
0.01	10	0.9	1*
0.1	100	0.8	1*
1	1000	0.7	1*
5	5000	0.3	1*
10	10000	0.2	1*
20	20000	0.1	1*
40	40000	0	1*

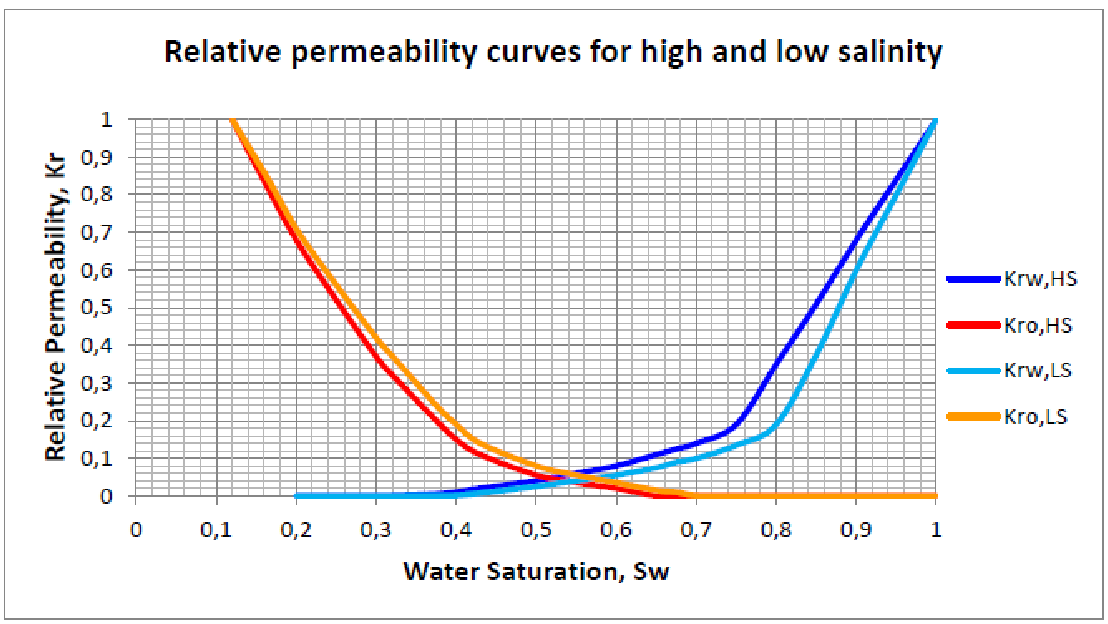

Figure 9. Relative permeability profile for high and low salinity (Kossac, 2012)

3.2.3. Low salinity alkaline flooding Model

Low salinity alkaline flooding is a hybrid enhanced oil recovery (EOR) method that combines the benefits of low salinity water flooding and alkaline flooding to improve oil recovery. This approach leverages the mechanisms of wettability alteration, interfacial tension (IFT) reduction, and multicomponent ionic exchange to enhance the displacement efficiency of oil. The model for low salinity alkaline flooding simulates the interactions between injected fluids, reservoir rock, and crude oil to predict recovery performance under specific reservoir conditions.

To implement low salinity alkaline model in the Eclipse reservoir simulation, the ALKALINE keyword must be activated in the data file. Additionally, the oil-water interfacial tension (IFT) as a function of alkaline concentration needs to be specified. In this study, the alkaline properties from Maheshwari Y.K.'s 2011 research were utilized as input parameters. Table 3 presents the IFT multipliers as a function of alkaline concentration used in this project. Furthermore, the SALINITY keyword in the PROPS section should be used to specify the salinity of the injected water, which is critical for low salinity flooding.

Table 3. IFT multipliers as a function of alkaline concentration (Maheshwari Y.K.'s 2011)

Alkaline Concentration (kg/m3)	Water/oil Surface Tension Multiplier
0.0	1.0
6.0	0.5
15.0	0.3
20.0	0.1
30.0	0.0

3.2.4. Low salinity surfactant flooding Model

Low Salinity Surfactant Flooding Model is an enhanced oil recovery (EOR) method that combines the effects of low salinity water flooding and surfactant flooding to improve oil recovery from a reservoir. This model takes advantage of both the wettability alteration capabilities of low salinity water and the reduction of interfacial tension (IFT) between oil and water achieved by surfactants. Together, these effects improve the efficiency of oil displacement and help mobilize residual oil that is difficult to recover through conventional methods. The success of this method in simulation studies depends on accurately modeling key parameters, such as the surfactant's adsorption onto the rock surface, which can diminish its availability for reducing IFT. High adsorption rates require larger surfactant volumes, increasing operational costs and potentially limiting recovery efficiency. By carefully calibrating surfactant properties and optimizing injection strategies, reservoir simulations can predict the potential incremental oil recovery and guide field-scale implementation of surfactant flooding. In this study surfactant properties were taken from Maheshwari Y.K. (2011), as an input data for surfactant model.

To enable the surfactant option in the reservoir simulator, the SURFACT keyword must be activated in the RUNSPEC section of the data file. Once this keyword is activated, it is necessary to define how the surfactant influences oil-water interaction (IFT). This can be achieved using the SURFST keyword in the PROPS section. Table 4 illustrates the oil-water interaction (IFT) as a function of surfactant concentration. Similar to low salinity alkaline flooding, SALINITY keyword must also be specified in the PROPS section to define the salinity of the injected water.

Table 4. Illustrates the oil-water interaction (IFT) as a function of surfactant concentration (Maheshwari Y.K.,2011).

Surfactant Concentration (kg/m3)	W/O Surface tension (N/m)
0.0	3.0E-02
0.1	1.0E-02
0.25	1.6E-03
0.5	4.0E-04
1.0	7.0E-05
3.0	8.0E-06
5.0	4.0E-06
10.0	6.0E-06
20.0	1.0E-05

3.2.5. Low salinity polymer flooding Model

Low salinity polymer flooding (LSWF + Polymer) combines the benefits of low salinity water flooding with the addition of polymer to improve the sweep efficiency and mobility control during the flooding process. In this method, the injected low salinity water helps to alter the wettability of the reservoir rock, reducing the capillary forces that trap oil in the pores, while the polymer acts to increase the viscosity of the injected water. This combination improves the displacement of oil by reducing the water-oil mobility ratio, thus enhancing the overall recovery. The presence of polymer also helps to reduce the effect of heterogeneity in the reservoir by improving the uniformity of the flood front. The model for low salinity polymer flooding in reservoir simulation requires input parameters for both low salinity water properties and polymer characteristics, such as viscosity and adsorption, to accurately simulate the process.

To enable the low salinity polymer flooding option in the reservoir simulator, both the POLYMER and low salinity keywords must be activated in the Eclipse data file. The POLYMER keyword is activated in the RUNSPEC section. Once the POLYMER keyword is activated, it is necessary to specify how the polymer influences the mobility of water and the viscosity of the injected fluid. This can be done using the PLYVISC keyword in the PROPS section, which defines the relationship between polymer concentration and water viscosity. Furthermore, the adsorption of polymer onto the rock surface can be accounted for by using the PLYADS keyword to define polymer retention in the reservoir. Additionally, the low salinity effects on fluid properties should be defined using the LSWF keyword in the data file to specify the low salinity injection properties. Tables 5 and 6 will provide the polymer viscosity and polymer adsorption as a function of polymer concentration.

Table 5. Polymer viscosity as a function of polymer concentration (Sheng, J.J., 2011)

Salinity (ppm)	P = 0ppm	P = 1000ppm			P = 2000ppm		
	Visc (cp) @ 120°C	Visc(cp) @25°C	Visc (cp) @120°C	Multiplier	Visc (cp) @25°C	Visc (cp) @120°C	Multiplier
1	0.5	195	59.5	119	215	65.7	131
10	0.5	190	58.0	116	211	64.4	129
100	0.5	150	45.8	92	198	60.5	121
1000	0.5	80	24.4	49	110	33.6	67
5000	0.5	25	7.6	15	42	12.8	26
10000	0.5	18	5.5	11	29	8.9	18
20000	0.5	12.5	3.8	8	20	6.1	12
40000	0.5	10	3.1	6	15	4.6	9

Table 6. Polymer adsorption as a function of polymer concentration (Maheshwari Y.K., 2011)

Polymer Concentration (kg/m3)	Polymer Adsorption by rock (mg/kg)
0.0	0.00
1.0	0.0017
2.0	0.0017

3.2.6. Low salinity Alkaline-Surfactant-Polymer (ASP) flooding model

Low salinity Alkaline-Surfactant-Polymer (ASP) flooding model combines the benefits of Low salinity, alkaline, surfactant, and polymer flooding to maximize oil recovery. Low salinity and alkaline reduces oil-water interfacial tension by reacting with acidic components in the crude oil to generate in-situ surfactants, which help mobilize trapped oil. Surfactants further lower interfacial tension, enhancing the displacement of residual oil. Polymers increase the viscosity of the injected fluid, improving the water-oil mobility ratio and sweep efficiency while mitigating viscous fingering and channeling in high-permeability zones. Additionally, alkaline reduces the adsorption of surfactants and polymers onto the rock surface, preserving their effectiveness. This synergistic combination addresses multiple challenges, including improving displacement efficiency, reducing water breakthrough, and mobilizing oil from less accessible areas.

In a reservoir simulator, there is no specific keyword to directly activate the Low salinity Alkaline-Surfactant-Polymer (ASP) flooding option, as this method combines multiple individual recovery mechanisms. To simulate Low salinity with ASP flooding, the keywords for alkaline, surfactant, polymer, and low salinity water flooding must be activated and configured together. When these individual models are defined in the data file, the simulator automatically integrates them and provides results for the combined low salinity with ASP process. Therefore, the low salinity ASP model and its properties are based on the parameters and properties of each individual method, as previously specified in the simulation setup.

4. Results and discussions

This section will present the results of the various cases that were mentioned in the methodology and provide a detailed discussion of each scenario individually.

4.1. High salinity water injection Model (Base Case)

Figure 10 represents the base case scenario, which involves conventional water flooding using water with a salinity of 40,000 ppm. In this scenario, water injection started from the first day of production. The figure displays three critical parameters over time: reservoir pressure (FPR), water cut (FWCT), and oil recovery (FOE). Although water injection began immediately, the reservoir pressure showed a noticeable response only after approximately 182 days. This delay is attributed to the time required for the injected water to fill up the void spaces within the reservoir. The injected high-salinity water caused the water cut to increase sharply, reaching nearly 100% after 2 years, indicating that most of the produced fluids were water rather than oil.

Regarding oil recovery, the high-salinity water flooding achieved a cumulative oil recovery of 37%. This recovery efficiency highlights the limitations of conventional water flooding in high-salinity conditions, as the sharp increase in water cut significantly diminishes oil production over time.

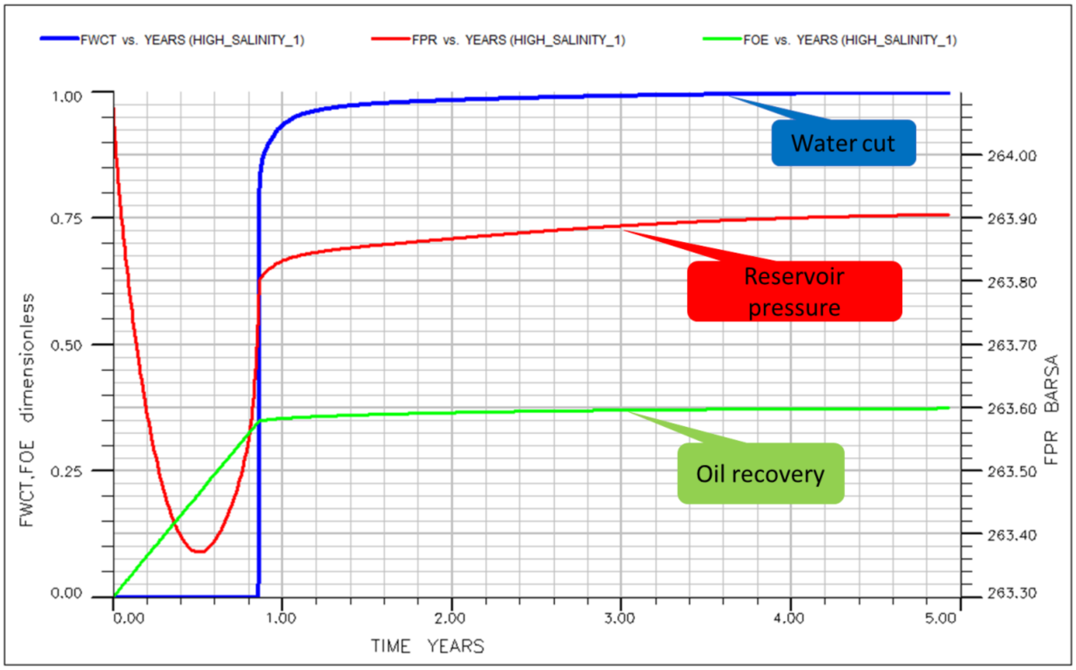

Figure 10. Reservoir pressure (FPR), Field water cut (FWCT) and Oil recovery (FOE) for high salinity water injection model

4.2. Low salinity water injection Model

Figure 11 represents the low-salinity case scenario, where water with a salinity of nearly 0.0 ppm is injected into the reservoir. Similar to the base case scenario, water injection begins on the first day of production. The figure shows three key reservoir parameters over time: reservoir pressure (FPR), water cut (FWCT), and oil recovery (FOE). Figure 11 reveals that oil recovery reaches 63%, significantly higher than the 37% achieved in the base case scenario using high-salinity water flooding. This improvement highlights the enhanced efficiency of low-salinity water in mobilizing and displacing residual oil. Unlike the base case, where reservoir pressure began to increase after approximately 182 days, the low-salinity case shows a more delayed response, with reservoir pressure starting to rise gradually only after 365 days. This extended delay could indicate differences in the fluid-rock interaction dynamics or the fill-up time required for low-salinity water to impact the reservoir pressure. Additionally, the water cut in this scenario is reduced from 100% (observed in the base case) to 94%, which demonstrates a lower production of water relative to oil. This reduction in water cut suggests that low-salinity flooding not only improves oil recovery but also mitigates excessive water production, thereby enhancing the overall production efficiency compared to the high-salinity case.

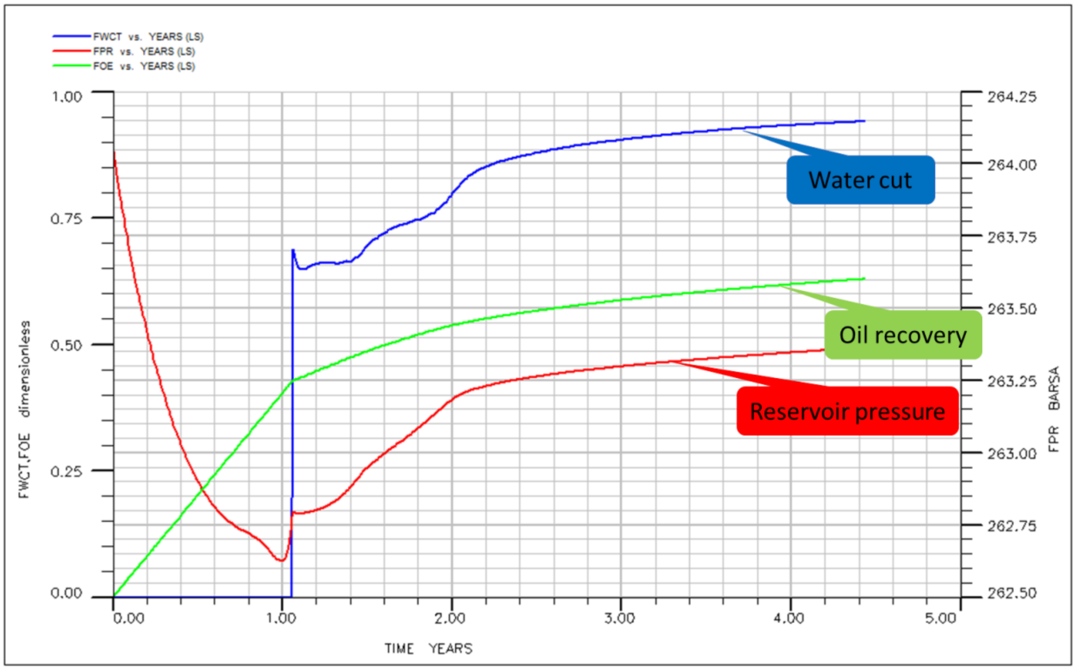

Figure 11. Reservoir pressure (FPR), Field water cut (FWCT) and Oil recovery (FOE) for low salinity water injection model

4.3. Low salinity alkaline flooding Model

Figure 12 represents the case of injecting a combination of low-salinity water and alkaline into the reservoir. Similar to the other scenarios, the injection started on the first day of production. Figure 12 illustrates the trends in reservoir pressure (FPR), water cut (FWCT), and oil recovery (FOE) for this scenario. The oil recovery in this case is 58%, which is a notable improvement over the base case recovery of 37%. However, it is slightly lower than the 63% recovery achieved in the low-salinity case. The slightly reduced recovery compared to the low-salinity scenario could be attributed to the combined effects of alkaline flooding, which might not have significantly enhanced oil displacement in this reservoir condition, or it might have affected the compatibility of the fluids in the system.

The reservoir pressure starts to increase gradually after 300 days, which is slightly earlier than the 365-day delay observed in the low-salinity case, likely due to the additional displacement mechanisms introduced by the alkaline. In terms of water cut, there is no significant difference compared to the low-salinity case; both scenarios show a water cut of approximately 94%.

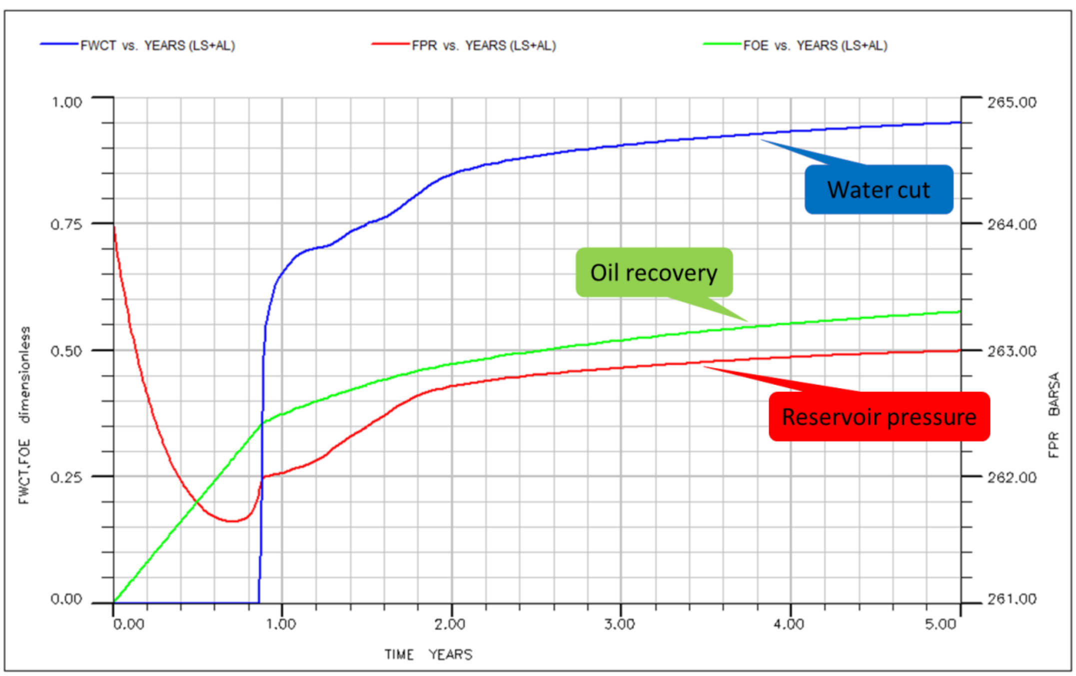

Figure 12. Reservoir pressure (FPR), Field water cut (FWCT) and Oil recovery (FOE) for low salinity alkaline flooding model

4.4. Low salinity surfactant flooding Model

Figure 13 shows the results for the case of injecting a combination of low-salinity water and surfactant into the reservoir. Similar to the other scenarios, injection began on the first day of production. The oil recovery for this case is 60%, which is significantly better than the 37% achieved in the base case. It is also higher than the combination of low salinity with alkaline but lower than the low-salinity-only case, which yielded a recovery of 63%. The reduced recovery compared to the low-salinity scenario could be attributed to the surfactant's specific interaction with the reservoir conditions, which may not have maximized oil mobilization as effectively.

The reservoir pressure begins to increase gradually after 256 days, earlier than in the low-salinity case (365 days) and the low-salinity and alkaline combination (300 days). This earlier pressure response indicates that the addition of surfactant slightly enhances pressure dynamics. In terms of water cut, the combination of low-salinity water and surfactant shows no significant reduction compared to the other cases. At the end of the simulation, the water cut for this scenario stabilizes at 92%, which is slightly better than the 94% observed in the low-salinity case and the combination of low salinity with alkaline. This indicates that while surfactant addition improves recovery, it does not drastically reduce water production.

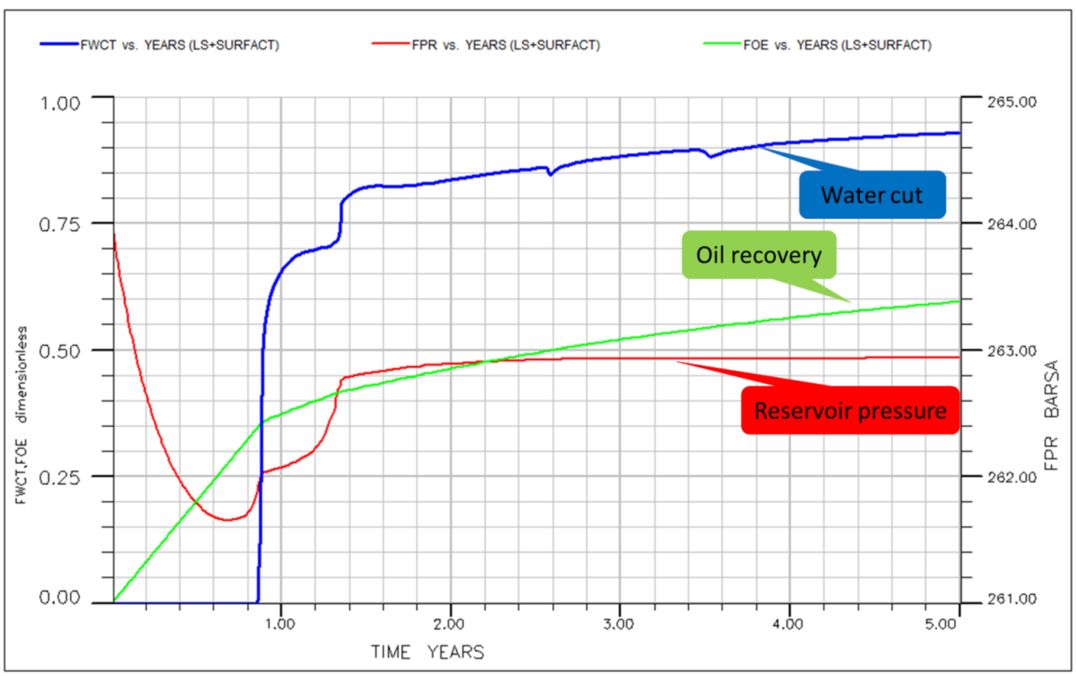

Figure 13. Reservoir pressure (FPR), Field water cut (FWCT) and Oil recovery (FOE) for low salinity surfactant flooding model

4.5. Low salinity polymer flooding Model

Figure 14 illustrate the results for the case of injecting low-salinity water combined with polymer into the reservoir, with injection starting on the first day of production. The results show that the oil recovery for this scenario is 38%, which is comparable to the recovery achieved in the high-salinity case. This suggests that the addition of polymer does not significantly enhance oil recovery beyond the baseline performance of high-salinity injection. The relatively low recovery, especially when compared to other enhanced recovery techniques such as low salinity alone (63%) or combinations like low salinity with surfactant (60%), may indicate insufficient polymer effectiveness under the given reservoir conditions. Reservoir pressure begins to increase gradually after approximately 182 days, but the rise is not as pronounced, suggesting a limited impact of the polymer on reservoir dynamics. The water cut stabilizes at 99%, which is very high and nearly identical to the result observed in the high-salinity case. This indicates that water breakthrough and production dominate this scenario, with the polymer failing to significantly reduce water cut. Compared to other enhanced recovery methods, such as low-salinity water with surfactant or alkaline, this method results in much lower oil recovery and higher water cut, highlighting its limited effectiveness in this particular reservoir.

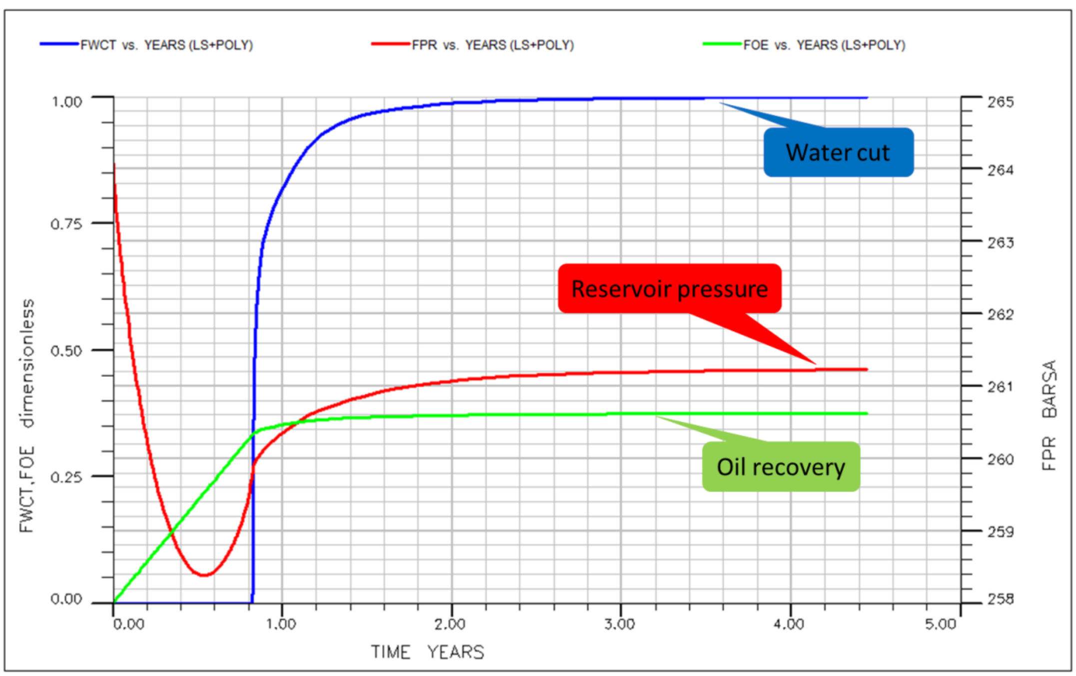

Figure 14. Reservoir pressure (FPR), Field water cut (FWCT) and Oil recovery (FOE) for low salinity polymer flooding model

4.6. Low salinity Alkaline-Surfactant-Polymer (ASP) flooding model

Figure 15 represents the simulation results for the low-salinity ASP (alkaline-surfactant-polymer) flooding model, showcasing its high performance compared to other injection cases. Injection was initiated on the first day of production. The plot illustrates the reservoir pressure (FPR), water cut (FWCT), and oil recovery (FOE) over five years. The oil recovery achieved is 72%, which is significantly higher than other scenarios such as high salinity injection, low salinity alone (63%), and combinations like low salinity with surfactant or alkaline. This demonstrates the effectiveness of combining low salinity with ASP in enhancing recovery by improving sweep efficiency and mobilizing residual oil. The reservoir pressure increases gradually after approximately one year, reflecting the supportive pressure maintenance provided by the ASP flooding. The water cut stabilizes at 94%, which is consistent with other enhanced recovery scenarios, indicating no significant reduction in water production compared to the base case or other injection methods. Overall, the low-salinity ASP flooding model demonstrates its superior oil recovery performance while maintaining a comparable water cut, making it an effective strategy for maximizing oil production in this reservoir.

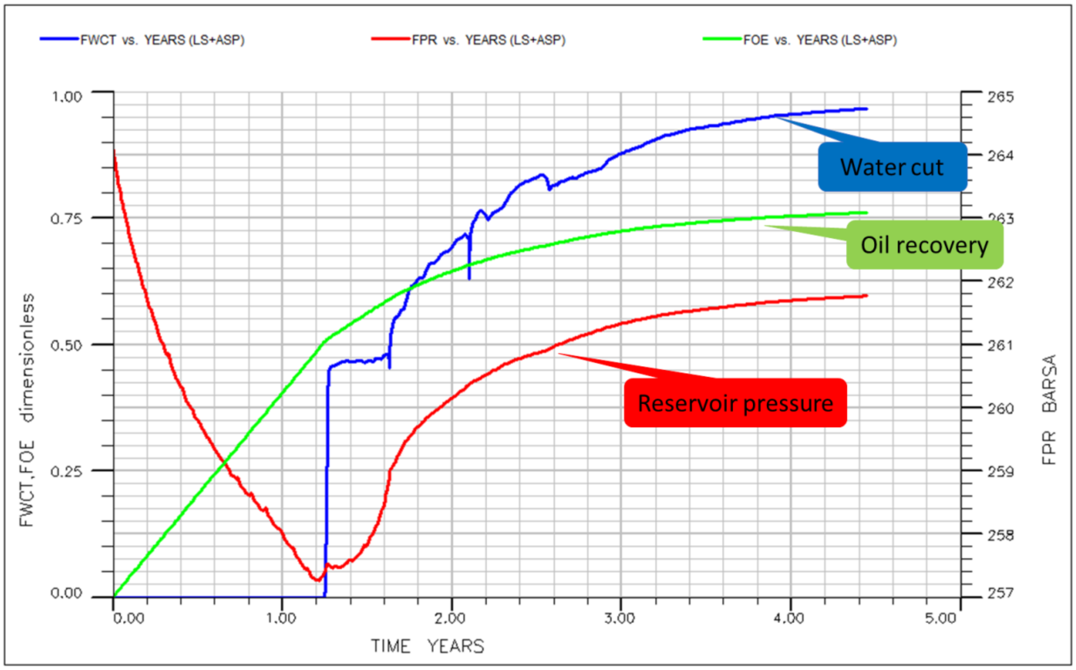

Figure 15. Reservoir pressure (FPR), Field water cut (FWCT) and Oil recovery (FOE) for low salinity ASP flooding model

4.7. Summary and compare study cases

Figure 16 presents a comparison of the field oil production rates across all studied cases. It is evident that the low-salinity ASP flooding achieves a prolonged plateau lasting approximately 15 months, followed by a gradual decline in production. In contrast, the other cases exhibit shorter plateaus and experience a more rapid decline in production rates.

The superior performance of the low-salinity ASP flooding can be attributed to its ability to enhance oil mobilization and recovery efficiency through a combination of low salinity, surfactant, and polymer effects. This synergy improves sweep efficiency and reduces residual oil saturation, resulting in the highest oil recovery of 72% compared to other scenarios (Figure 17).

Notably, the water breakthrough time for the low-salinity ASP flooding occurs after 15 months, significantly later than the 12 months observed for low-salinity water flooding. The other cases, in comparison, exhibit water breakthrough at approximately 9 months (Figure 18). This delayed water breakthrough further contributes to the high recovery efficiency of 72% achieved in the low-salinity ASP flooding case, making it the most effective among all the scenarios studied.

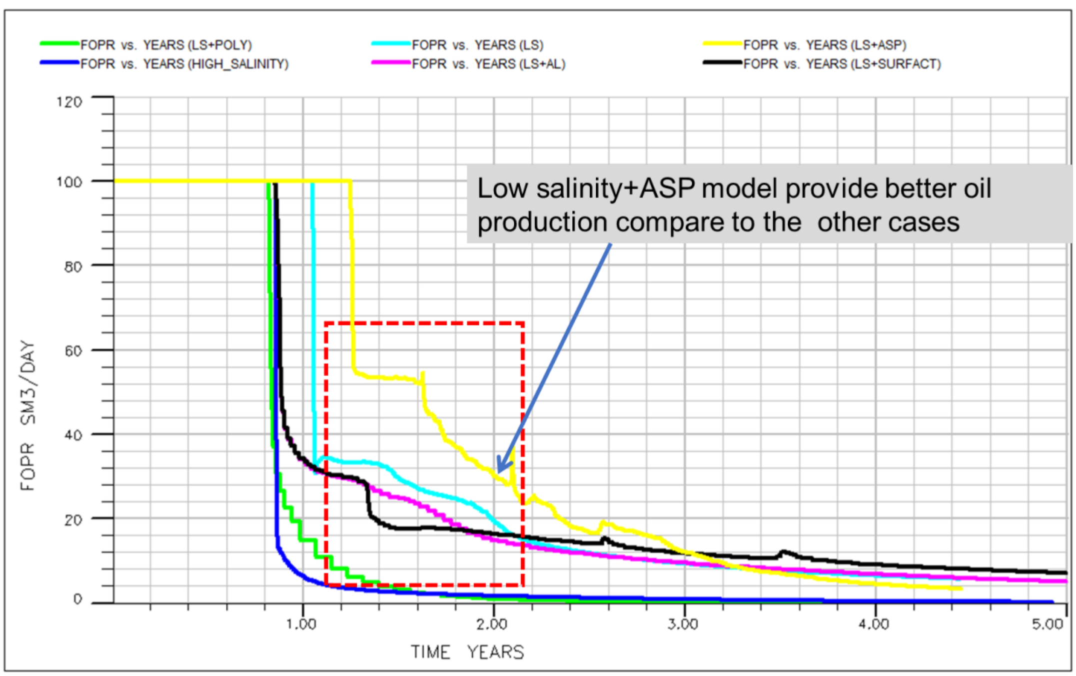

Figure 16. Compare field oil production rate (FOPR) for studied cases

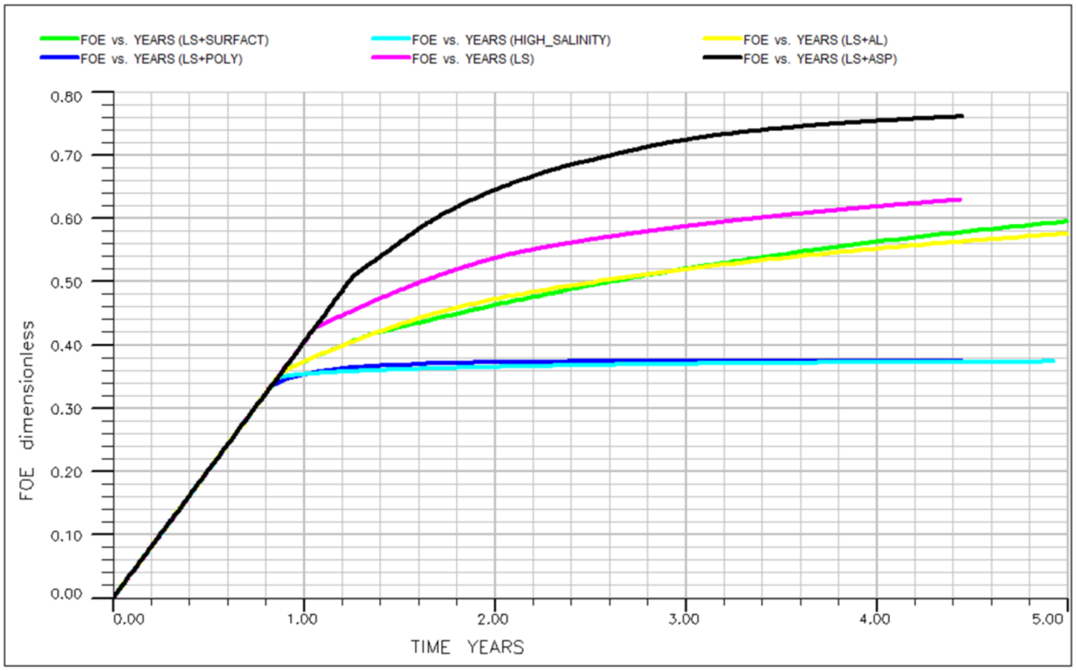

Figure 17. Compare oil recovery (FOE) for studied cases

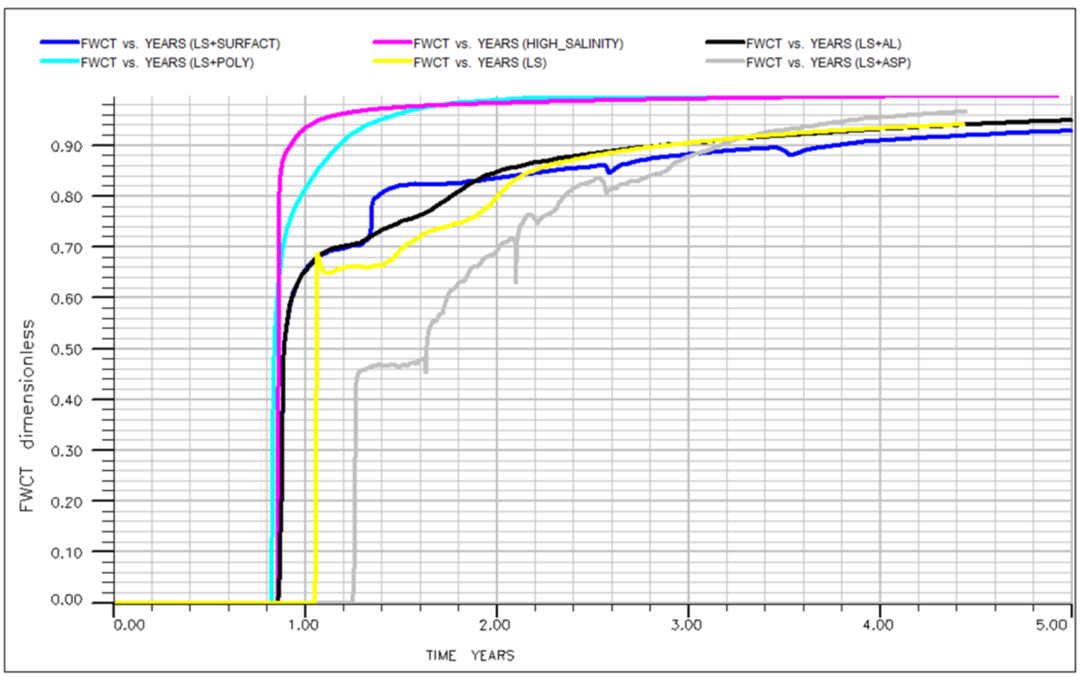

Figure 18. Compare field water cut (FWCT) for studied cases

5. Conclusions

This study uses simulation to evaluate the performance of low-salinity water flooding in combination with chemical methods for enhanced oil recovery. The key findings are as follows:

- High salinity water flooding resulted in the lowest oil recovery at 37%, with early water breakthrough and the water cut nearing 100%.
- With low salinity water flooding, oil recovery increased significantly to 63% from 37% in the high salinity case, with water breakthrough delayed to around 12 months, while the water cut remained high at 94%.
- The simulation results demonstrate that enhanced oil recovery methods combining low-salinity water with chemicals such as surfactants, polymers, and alkali significantly outperform the high salinity water flooding.
- Combining low salinity with polymer provide lowest oil recovery among all the combinations. This is due to increase the viscosity of injected fluid which hinders the ability to reach certain areas of the reservoir, especially in regions of lower permeability.
- Low salinity ASP flooding is the most effective, offering the highest recovery, delayed water breakthrough, and sustained production.

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Appendices

Base Case Data File

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High Salinity water injection
DIMENS
50   50    6/
OIL
WATER
LOWSALT
METRIC
TABDIMS
2    1   20   20    1   20 /
WELLDIMS
4    10    1    4 /
START
1 'JAN' 2023/
UNIFIN
UNIFOUT
NSTACK
50 /
UDQDIMS
3* 10 /
GRID
==========================================================
INIT
DX
15000*3   /
DY
```

```
15000*3   /
DZ
15000*3   /
NOECHO
INCLUDE
permx15000.dat /
permy15000.dat /
permz15000.dat /
poro15000.dat /
TOPS
2500*2600 /
ECHO
PROPS
=============================================================
LSALTFNC
--LSALTFNC Table
--kg/sm3
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1   0.8     1
4   0.2     1
5    0      0
35  0       0
45  0       0 /
/
SWOF
--       SWAT        KRW         KROW      PCOW
          0.2             0             0.6          0
          0.24            0             0.4          0
        0.2679          0           0.2661         0
        0.2857       0.0001         0.2268         0
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0.3214	0.001	0.1575	0
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0.375	0.0094	0.0772	0
0.3929	0.016	0.0567	0
0.4107	0.0256	0.0394	0
0.4286	0.039	0.0252	0
0.4464	0.0572	0.0142	0
0.4643	0.081	0.0063	0
0.4821	0.1115	0.0016	0
0.5	0.15	0	0
1	1	0	0 /

--Low salinity curves

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0.4	0	0.269	0
0.4179	0.001	0.2407	0
0.4357	0.0041	0.2134	0
0.4536	0.0092	0.1873	0
0.4714	0.0163	0.1624	0
0.4893	0.0255	0.1386	0
0.5071	0.0367	0.1162	0
0.525	0.05	0.1	0
0.5429	0.0653	0.085	0
0.5607	0.0827	0.07	0
0.5786	0.102	0.06	0
0.5964	0.1235	0.05	0
0.6143	0.1469	0.04	0
0.6321	0.1724	0.034	0
0.7	0.27	0.015	0

```
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      0.8           0.8         0             0
      1              1          0             0 /
PVDO
  200     1.0        0.47
  280    0.999     0.47
  300    0.998     0.47
/
ROCK
270 .3E-5 /
DENSITY
-- o        w            g
  850     1000       1.2 /
 PVTWSALT
   270.0       0.0  /
  0.0         1.030             4.6E-5         0.5            0.0
  100         1.030             4.6E-5  0.5     0.0 /

REGIONS
============================================================
SATNUM
15000*1 /
LWSLTNUM
15000*2 /
RPTREGS
24*0 /
RPTREGS
SURFNUM LWSLTNUM LSLTWNUM /
SOLUTION
============================================================
```

```
EQUIL
-- Datum   Pressure       WOC
   2680       270            2680      1*           2000/
SALTVD
5000            45.0
5500            45.0 /
RPTRST
'BASIC=2'  FIPSALT  SALT  /
SUMMARY
==========================================================
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FOPT
WWIT/
FSPR
FSPT
FSIR
FSIT
FSIP
FWIR
FOPR
FGPR
FPR
FOPV
FWIT
FOE
TCPU
FSPR
FSIP
FSIC
FSPC
```

```
ALL
SEPARATE
RUNSUM
MSUMLINS
MSUMNEWT
SCHEDULE
========================================================
TUNING
0.001  4 /
 /
2*  50 /
WELSPECS
OP          G       50      50      2600      'OIL'  /
IFRESH      G       1       1       2600      'WAT'  /
IHSALT      G       1       1       2600      'WAT'  /
/
COMPDAT
  OP         1*   1*     1     6  'OPEN'     0  .0     0.5 /
  IFRESH     1*   1*     1     6  'OPEN'     0  .0     0.5 /
  IHSALT     1*   1*     1     6  'OPEN'     0  .0     0.5 /
/
WCONPROD
 OP     OPEN     RESV     4*    100    0.0    4* /
/
WCONINJE
 IFRESH      WAT     OPEN     'RESV'    1*    100  /
/
WSALT
 IFRESH 0.0 /
/
```

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WCONINJE
 IHSALT      WAT      OPEN     'RESV'    1*    100  /
/
WSALT
 IHSALT 35.0 /
/
WELOPEN
IFRESH SHUT /
IHSALT OPEN /
/
TSTEP
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END
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