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Numerical Study of Low Salinity Water Flooding in Naturally Fractured Oil Reservoirs

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Abstract

Due to the increase of the activities in the oil industries, higher interest has been given to enhance the recover the trapped oil and produce more oil from the matured reservoirs. Worldwide, enhanced oil recovery (EOR) is implemented in most reservoirs to recover additional amounts of oil that are not recovered during secondary recovery by water flood or gas injection. Recently, a numerous techniques such as thermal, miscible, immiscible and chemical has proposed to enhanced oil recovery and to increase the producible oil from oil reservoirs. The suitability and the success of a specific EOR process are highly sensitive to reservoir and fluid characteristics, recovery efficiency, availability of injected fluids, and costs. One of the common techniques which have been proposed recently is low salinity water flooding where the sea water with a controlled salinity and salt content is used to alter the rock wettability or enhance the fine migration and resulted in higher oil production. This study aims to investigate the possibility of using low salinity water flooding in naturally fractured reservoirs. The wettability changes are taking into account in terms of oil/water relative, saturation and capillary pressure as these parameters play a key role during the simulation of brine injection. The results show that the oil recovery significantly increases specially for water wet reservoirs as the reason behind is the decreasing water production after the breakthrough of the low saline brines.

Keywords: enhance oil recovery, low salinity water injection, naturally fractured reservoir

1. Introduction

Enhanced oil recovery (EOR) is a technique that used to recover trapped oil left in reservoirs after primary and secondary recovery methods. Although, EOR is a challenging process

where a variety of parameters play an important role such as harsh environments; EOR processes are applied worldwide in most reservoirs to retrieve additional amounts of oil which it cannot be recovered during secondary recovery by waterflood or gas injection.

Due to the expected increase in energy consumption worldwide which is assumed to exceed 50% by the end of 2030, different path of renewable resources has been proposed to meet this growth and energy demand. Primary and secondary oil recovery which is considered as predominate energy resource produce only 15–30% of the oil original in place (OOIP) [1] and the percentage of the recovered oil is mainly depend on the compressibility of the fluids and reservoir initial pressure. More than 50% of the reserved oil subsequent to the OOIP will be trapped which in some cases is amenable to tertiary or enhance-oil-recovery process [2]. The difficulty of oil recovery was due to the chemical equilibrium between the crude oil, formation water and the rock structure and characteristic. The distribution of the oil and water within the porous rock is depend on the contact between the rock surface and the two fluids or in the other hand is depend on the rock wetting properties.

EOR stages encompass a variety of processes, including miscible flooding processes, chemical flooding process, thermal flooding processes, and microbial flooding processes. Water flooding is one of the EOR mechanisms where injected water with certain specification was used to maintain reservoir pressure and improve reservoir sweep efficiency. In order to improve the oil recovery and increasing production efficiency, water flooded was recently used in most of the reservoirs where it was initially used to support the reservoir pressure and maintain it above the oil bubble pressure and take the advantage of the viscous forces into displacement of the oil by the water. Injection of water with different composition within the initial formation, water can disturb the established reservoir chemical equilibrium and results in improved oil recovery. To evaluate the usage of smart water as EOR fluid a well chemical understanding of the most important parameters dictating the wetting properties of oil reservoir is highly needed. Low salinity water injection (LSWI) is one of the emerging improved oil recovery techniques for boosting the oil recovery from waterfloods [3]. The LSWI technique received increasing attention in the oil industry and has the potential of being cost effective compared to other EOR techniques because of its simplicity, higher oil recovery performance, and environmental friendly when compared with conventional high salinity water flooding and other EOR approaches. The main concerns with using LSWI are water sourcing and water disposal. The successful EOR approach using LSWI has been related to several factors linked to the composition of injected brine such as fine clay minerals migration, interfacial tension reduction, wettability alteration, controlling pH, and emulsion formation. The effect of low salinity water flooding has been shown at laboratory-scale and to a limited extent at field-scale using both sandstone and carbonate rocks. The modification of the injected brine composition was proved that it could improve the oil recovery factor of conventional water flooding up to 38% [4].

Several studies have been heightened that the salinity of the connate water is the main factor controlling the higher oil recovery where the salinity of the injected water must be much lower than the salinity of the connate water. Investigator found that an improved in oil recovery by using low salinity water injection only happen when clay sandstone minerals is existed along with the crude oil. The interpretation for this phenomenon was linked to permeability reduction caused by the fine migration leading to increasing in more pressure drop and higher oil production, since most observations reviled that pressure drop was strictly tied

to incremental recovery [5]. Which is not the case with the carbonates rock since carbonate rock reservoir where it may contain clays minerals, but these minerals as regularly is trapped within the rock matrix and not considerably exaggerated by the injected fluid.

Furthermore, the interaction between the negatively polar crude oil and positively charged carbonates is much higher than the sandstone rocks [6] therefore, the wettability alteration mechanism in the case of carbonate rock is more complicated compare with the silica and clay due to the various contributions including fine migration, pH [7], and salinity effect [8, 9]. Change in wettability in carbonate rock from oil wet to water wet or mix wet can lead to an incremental improve in oil recovery. Høgnesen et al. [10] concluded that any modification in the composition of the injected water can altered the rock wettability. Additionally, the effect of sulfate ions within the injected water in wettability iteration have been investigated by Høgnesen et al. [10] where their results show that increasing the concentration of sulfate ion at high temperature modify the wettability in carbonates, and result in higher oil recovery. Moreover, Webb et al. [11] conducted a study that compared oil recovery from a North Sea carbonate core samples using sulfate-free brine, with seawater contains sulfate. Their results displayed that the seawater contains sulfate ions has ability to modify the wettability of the carbonate system to water wet state.

Generally, few studies regarding the effect of wettability alteration for carbonate rocks have been established so far and this was mainly due to incomplete understanding of complex chemical interactions between rock, oil and brine. Experimental and modeling studies are still progressing to gain more insight into the mechanism underlying the effect of LSWI on oil recovery. Therefore, this work presents a numerical simulation study to evaluate production potential of naturally fractured reservoirs under low salinity water flooding. The simulation model based on hybrid approach of using permeability tensor and discrete fracture approaches. The governing equations use for the simulation are expanded using finite element technique.

2. Background

Low salinity water flooding is one of the incremental oil recovery techniques which inject low salinity water to alter the wettability or assist at fine migration from the reservoir to increase the oil production and reduce the residual oil saturation. The mobility and migration of the reservoir fines mainly depends on the salinity of the water flood where injection of the low salinity water enhances the fines migration. Migrate particles can clog pore throats and act as fluid flow hindrance and results in reduction of the permeability in the clogged throats. Where in the oil and gas recovery practices these phenomena is intentionally avoided as it damages the permeability and hence reduction in permeability translates into reduction in productivity from reservoir wells. Meanwhile, by inducing damage to the permeability of the reservoir in water swept zones; less permeable water zone to a high permeability oil zone will be occurring. The process of decreasing the fluid mobility in one zone is known as mobility control process. As result of low salinity water flooding; fine mobilization and its accumulation on pore throats can be identified by an increase in the pressure drop.

Studies have confirmed a pronounced effect of LSWI on oil recovery in both secondary and tertiary modes of injection. The importance of LWSI enhanced because it can be integrated with other EOR method such as chemical or miscible gas flooding. Bernard [12] the relative

effectiveness of fresh and salt waters in flooding oil from cores containing clays investigated the effect of Dang et al. [13] evaluated the merits of combining CO_2 with LSW injection (CO_2 -LSWAG) on the EOR through modeling, optimization and uncertainty assessment. They found that CO_2 -LSWAG.

Different mechanisms have been suggested regarding the effect of LSWI on sandstone rocks including fines migration, pH, multi-ion exchange (MIE), salting-in, and wettability alteration [14]. The wettability alteration process underlies the low salinity effect as the decrease in salinity increases the size of the double layer between the clay and the oil interface, which leads to organic material release [15].

Furthermore, the behavior of low salinity waterflooding can be summarized as follows [5]: (1) more oil can be produced if the brine salinity of the injected water is lower than the initial brine salinity in the core (2) reducing the initial brine salinity of the injected water during the stage enhance the pressure drop, (3) pressure drops reduced due to reducing of the core permeability due to presence of fine migration [16], (4) existence of connate water is beneficial to enhance the effect of low salinity water [17].

In addition, the effect of the salinity of the connate water on the oil recovery have been presented Sharma et al. [18] where they concluded that oil recovery increased significantly with the salinity of the connate brine. In addition, the performance of waterfloods is strongly affected by the composition of the crude oil and its ability to wet the rock surfaces, the salinity of the connate brine in the reservoir, and the height above the oil/water contact. This contribution was also supported by McGuire et al. [4].

Although the mechanism for the effect of low salinity water flooding is benign different from each other the main concept is to improved oil recovery.

In this study, we simulate low salinity water flooding under geomechanical effects. The simulation based on finite element technique, hybrid approach of permeability tensor and discrete fracture. The low salinity effect is taken under wettability changes during the simulation process.

3. Reservoir model development

This study presents a novel three dimensional poroelastic numerical model for simulation multiphase fluid flow in naturally fractured basement reservoirs. A hybrid approach is used in the simulation of fluid flow. In this approach small fractures are considered as part of matrix and flow is simulated by using single continuum approach. While flow through long fractures is simulated using a discrete fracture approach. The reservoir is divided into a number of grid blocks. Grid based full permeability tensors for short to medium fractures are calculated using Darcy's diffusivity equation. Cubic law is to simulate flow through long fractures that cuts through different grid blocks.

4. Methodology

4.1. Grid based full permeability tensors

A fractured porous medium composed of matrix with nonzero permeability and fractures with high permeability based on the fracture aperture [19]. In this medium, the fluid flows through matrix and fractures with transfer between these two structures. In which, each point in the matrix can be assigned a bulk permeability k_m , while each point in the fractures can be assigned k_{eff} .

In order to calculate the effective permeability tensors which represents an average permeability for the two structures, 3D cube is used to represent the matrix and fractures porous media (**Figure 1**) [17].

The fractured porous media is bounded in an impermeable cover with boundary conditions for pressures (P1 and P2).

The boundary conditions are: $p(x=0) = p_1$, $p(x=L) = p_2$, $J \cdot n = 0$ and $v = 0$ on s_1

The seepage velocity calculated based on the flow rate integration over fracture surfaces and matrix porous media and by using total volume of the block.

$$v = -\frac{k_m}{\mu} \nabla p \quad (1)$$

Where μ the fluid viscosity and Δp is the pressure change. The continuity equation for local seepage velocity in the matrix read as:

$$\nabla \cdot v = 0 \quad (2)$$

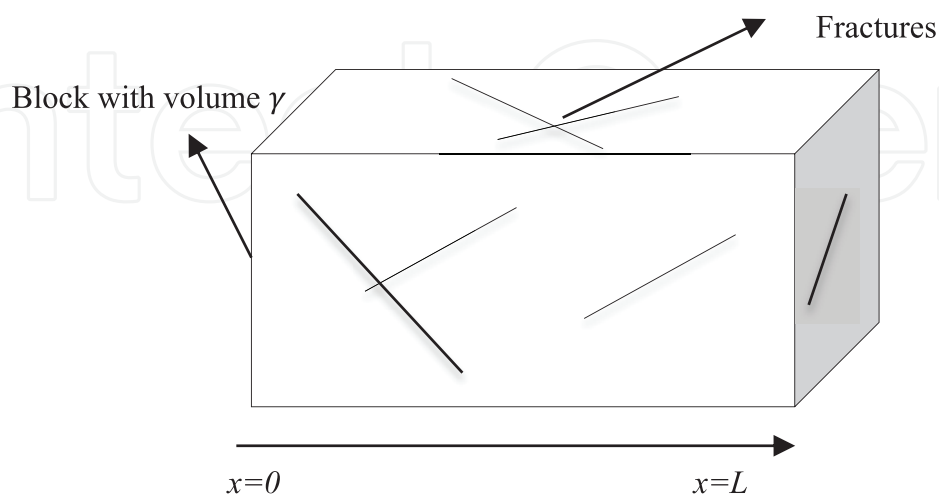


Figure 1. 3D cube used for permeability tensor calculations.

The hydraulic properties of fracture can be characterized by fracture transmissivity (aperture) and main flow rate is set parallel and normal to fracture plane. The flow rate J in fractures is usually defined by unit width of fracture and can be expressed by:

$$J = -\frac{k_{eff}}{\mu} \nabla_s p \quad (3)$$

In case of the flow is parallel to fracture plane, the seepage velocity normal to the fracture induces a pressure drop expressed by:

$$v = -\frac{1}{\mu} \nabla p \quad (4)$$

The effective fracture permeability of fracture can be describes by its aperture b as (in case the fractures are empty):

$$k_{eff} = -\frac{b^3}{12} \quad (5)$$

The mass conservation equation for the flow in a fracture is:

$$\nabla_s J = -(\vec{v} + \vec{v}^*) \cdot n \quad (6)$$

Where n the unit vector is normal to fracture plane, \vec{v}^* is the seepage velocity in the matrix on the side of n and \vec{v} is the seepage velocity on the opposite side.

This transport equation is implemented with the above-mentioned boundary conditions to calculate the permeability tensors.

Therefore, the total seepage velocity over the block is obtained by integrating the flow rates over fracture surfaces and matrix porous media. Then the results divided by the total block volume to calculate the block effective permeability tensor.

$$v_x = \frac{1}{\gamma} \left\{ \int_{\gamma_m}^- v_x dv + \int_{sf}^- J_x ds \right\} = \frac{-k_{eff}}{\mu} \frac{\partial p}{\partial x} \quad (7)$$

Where, sf is the surface for all fractures and γ is the matrix volume.

4.2. Simulation of low salinity water flooding

Darcy's law and continuity equations are governed two phase fluid flow system through fractures and matrix porous media [18].

The Darcy's law is expressed as:

$$\phi s_\pi u^{\pi s} = \frac{k_{ij} k_{r\pi}}{\mu_\pi} [-p_\pi + p_\pi g_i] \pi = w, nw \quad (8)$$

Continuity equation for wetting phase incorporating the effective overburden, maximum, and minimum stresses can be expressed as follow:

$$\begin{aligned}
 & -\nabla^T \left[\frac{k_{ij} k_{rw}}{\mu_w \beta_w} \nabla(p_w + \rho_w g h) \right] + \phi \frac{\partial}{\partial t} \left[\frac{\rho_w s_w}{\beta_w} \right] + \rho_w \frac{s_w}{\beta_w} \left[\left(1 - \frac{D}{3 K_m} \right) \frac{\partial \varepsilon}{\partial t} + \frac{Dc}{3 K_m} + \left(\frac{1-\phi}{K_m} - \frac{D}{(3 K_m)^2} \right) \frac{\partial p}{\partial t} \right] \\
 & + \rho_w Q_w = 0
 \end{aligned} \tag{9}$$

Continuity equation for non-wetting phase can be written as follow:

$$\begin{aligned}
 & -\nabla^T \left[\frac{k_{ij} k_{ro}}{\mu_o \beta_o} \nabla(p_o + \rho_o g h) \right] + \phi \frac{\partial}{\partial t} \left[\frac{\rho_o s_o}{\beta_o} \right] + \rho_o \frac{s_o}{\beta_o} \left[\left(1 - \frac{D}{3 K_m} \right) \frac{\partial \varepsilon}{\partial t} + \frac{Dc}{3 K_m} + \left(\frac{1-\phi}{K_m} - \frac{D}{(3 K_m)^2} \right) \frac{\partial p}{\partial t} \right] \\
 & + \rho_o Q_o = 0
 \end{aligned} \tag{10}$$

Where, ϕ is the porosity of the media, s_π is the saturation for each phase, $u^{\pi s}$ is the relative velocity vector between fluid phase and solid phase, k_{ij} is the permeability tensor, $k_{r\pi}$ is the relative permeability for each fluid phase π , μ_π , ρ_π and p_π are dynamic viscosity, density of fluid, and fluid pressure for each phase respectively, g_i is the gravity acceleration vector, β_π is the fluid formation volume factor, K_m is the bulk modulus of solid grain, D is the elastic stiffness matrix, and Q_π represents external sources or sinks.

The effect of low salinity has been taken on wettability changes which affect the relative permeability curve. Therefore, the salt concentration at each grid block has been calculated using Eq. (10) and the calculated saturations from Eqs. (9) and (10).

$$\frac{\partial C S_w}{\partial t} + Q_t \frac{\partial C f_w(S_w, C)}{\partial x} = 0 \tag{11}$$

Rearranging Eq. (11):

$$\frac{\partial}{\partial t}(S_w C) + Q_t \frac{\partial}{\partial x}(C) = 0 \tag{12}$$

Where C is concentration of a relevant solute in water, S_w is water saturation, f_w is water fractional flow, and Q_t is total flow rate.

The changes of oil and water relative permeability and capillary pressure are calculated using Eqs. (11)–(13).

$$k_{rw} = F_1 k_{rw}^L + (1 - F_1) k_{rw}^H \tag{13}$$

$$k_{ro} = F_1 k_{ro}^L + (1 - F_1) k_{ro}^H \tag{14}$$

$$P_{cow} = F_2 P_{cow}^L + (1 - F_2) P_{cow}^H \tag{15}$$

Where F_1 and F_2 are functions of the salt concentration, k_{rw} is the water relative permeability and k_{ro} is the oil relative permeability, P_{cow} is oil–water capillary pressure. The subscripts H and L are standing for high salinity and low salinity respectively.

The end point saturations are calculated by using the following equations:

$$S_{wco} = F_1 S_{wco}^L + (1 - F_1) S_{wco}^H \quad (16)$$

$$S_{wcr} = F_1 S_{wcr}^L + (1 - F_1) S_{wcr}^H \quad (17)$$

$$S_{wmax} = F_1 S_{wmax}^L + (1 - F_1) S_{wmax}^H \quad (18)$$

$$S_{owcr} = F_1 S_{owcr}^L + (1 - F_1) S_{owcr}^H \quad (19)$$

Where F_1 and F_2 are functions of the salt concentration, S_{wco} is the connate water saturation, S_{wcr} is the critical water saturation, S_{wmax} is the maximum water saturation and S_{owcr} is the critical oil saturation in water. The subscripts H and L are standing for high salinity and low salinity curves, respectively.

5. Validation of the model using 3D reservoir with a single fracture

In this case, a simple 3D reservoir with one fracture is used for validating the numerical model. The reservoir is built by using a commercial black oil reservoir simulator (CMG IMEX). The model dimensions are (10 m × 10 m × 5 m). The reservoir model includes 15 horizontal layers. Of these 15 horizontal layers, the 8th layer from the top is embedded as a fracture layer with different rock properties. The mesh is refined around the fracture layer

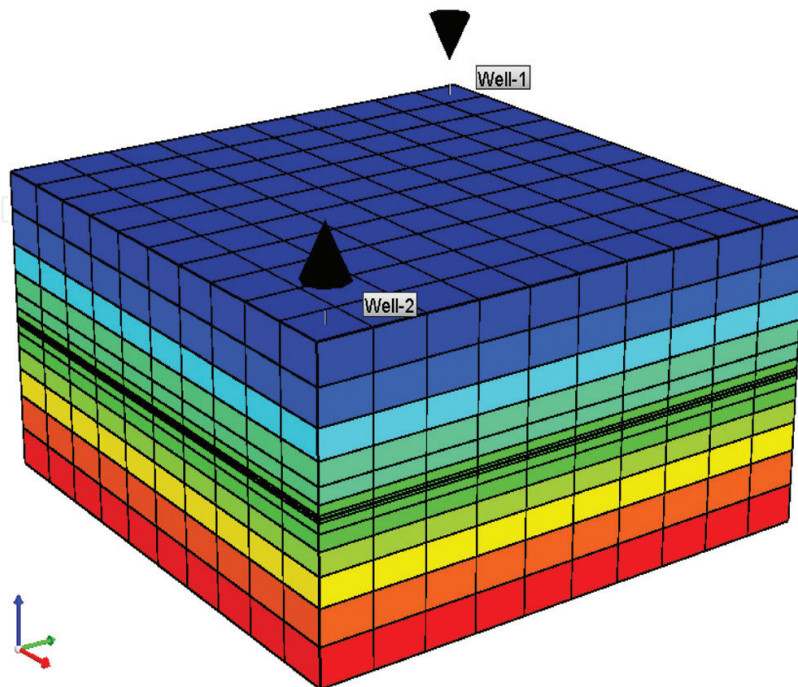


Figure 2. Reservoir fracture model used in CMG to validate the developed two phase fluid flow numerical model.

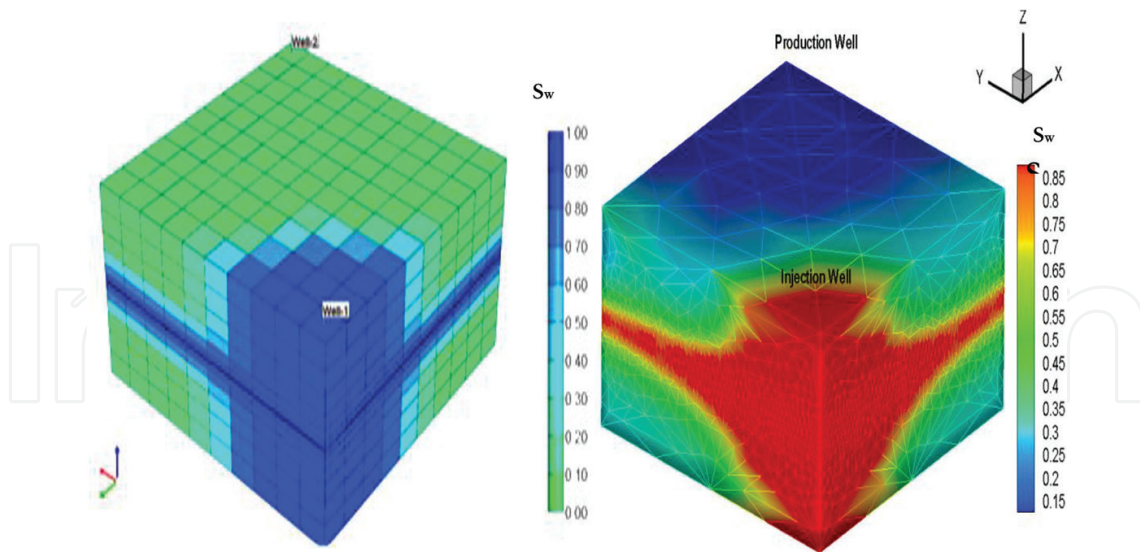


Figure 3. Water saturation profile after one day of water injection (a) CMG 3D model with one fracture introduced at eighth layer. (b) 3D model with one fracture introduced at the middle of the reservoir model used with the developed multiphase numerical model.

as shown in **Figure 2**. The matrix and fracture permeability are set at 0.01 md and 2 Darcy respectively. Linear relative permeability curve, one injector and one producer are used for the simulation of fluid flow.

Figure 3a and **b** show the water saturation profile obtained from CMG and two phase finite element numerical model, respectively. As can be seen from the figures, at the beginning of the injection, water moves fast inside the fracture due to its high permeability compared to the matrix permeability. With the pass of time (approximately a day), the water saturation starts to increase gradually inside the matrix elements. These figures show that the finite element numerical model is able to predict the same water saturation profile as that of CMG black oil reservoir simulator but with greater accuracy.

6. Fracture characterization

In this study, object based simulation technique is used to generate subsurface discrete fracture maps [20]. In this model, fractures are treated as objects and placed in the domain stochastically. The number of generated fractures is controlled by fracture intensity (0.1 m^{-1}) and fractal dimension parameters. The fractures are treated as objects with varying in radius, dip and azimuth angles.

6.1. Fracture intensity

The fracture intensity is an important parameter to give an indication about the probability of fractures occurrence in a discrete fracture model [21]. The fracture intensity is defined as the number of fractures per unit bulk volume. To calculate the fracture intensity, the reservoir is divided into a number of grid blocks and fractures that cut each block are defined. Then,

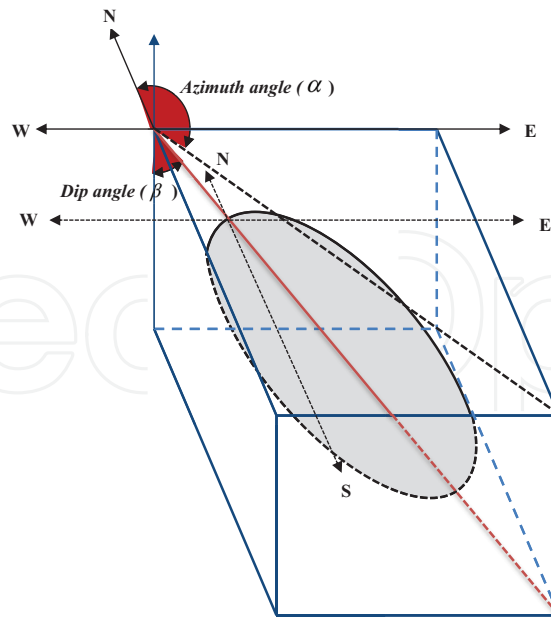


Figure 4. Description of the plane in which the fracture lies. The ellipse represents a fracture with (α is the fracture azimuth angle and β is the dip angle).

the number of these fractures is divided by the bulk volume of the corresponding grid block. Fracture intensity map is extracted from geological interpretations of reservoirs. Fracture intensity is expressed as:

$$\text{Fracture Intensity} = \frac{\sum_{i=1}^N \text{Area}}{\text{Volume}} \tag{20}$$

Where, N is the total number of fractures that intersect the corresponding grid block.

6.2. Fracture dip and azimuth

Each fracture in a discrete fracture model is defined by its properties which include fracture azimuth angle, dip angle, center point (x, y and z) and radius. Fracture azimuth is defined by the angle formed between the fractures plan and the geographic north. These angles are inferred from core and Fullbore Formation Micro imager (FMI) data. Fracture dip is the angle between the fracture plane and horizontal plane (see **Figure 4**) and inferred from the geological interpretations (e.g. dip of the geological formation). In object based simulation, the fractures azimuth angles are characterized by the Gaussian distribution while dip angles are assumed to be followed by normal distribution.

7. Results and discussion

The case study has been taken from a fractured reservoir located in United Arab Emirates. The studied reservoir (4500 m x 4500 m x 300 m) contains more than 14,000 long to short fractures. The reservoir has been divided into grid blocks (100 m x 100 m x 50 m) and fractured intersected with each block are determined. The fractures with length ($l < 40$ m) have

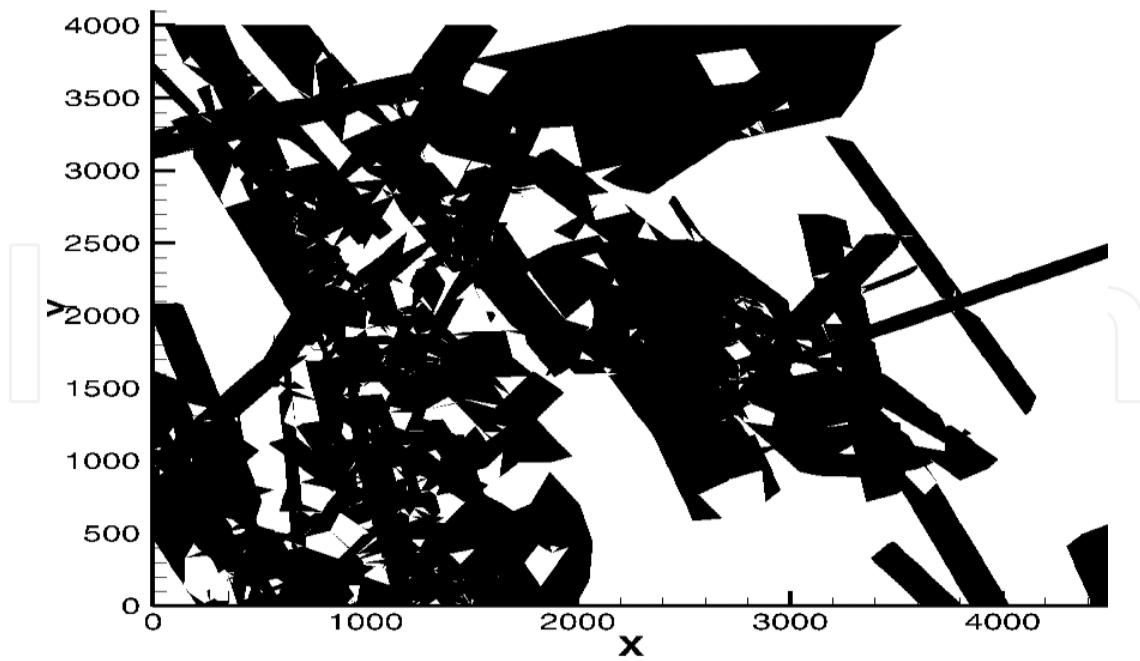


Figure 5. 2D view of fracture network for the studied reservoir.

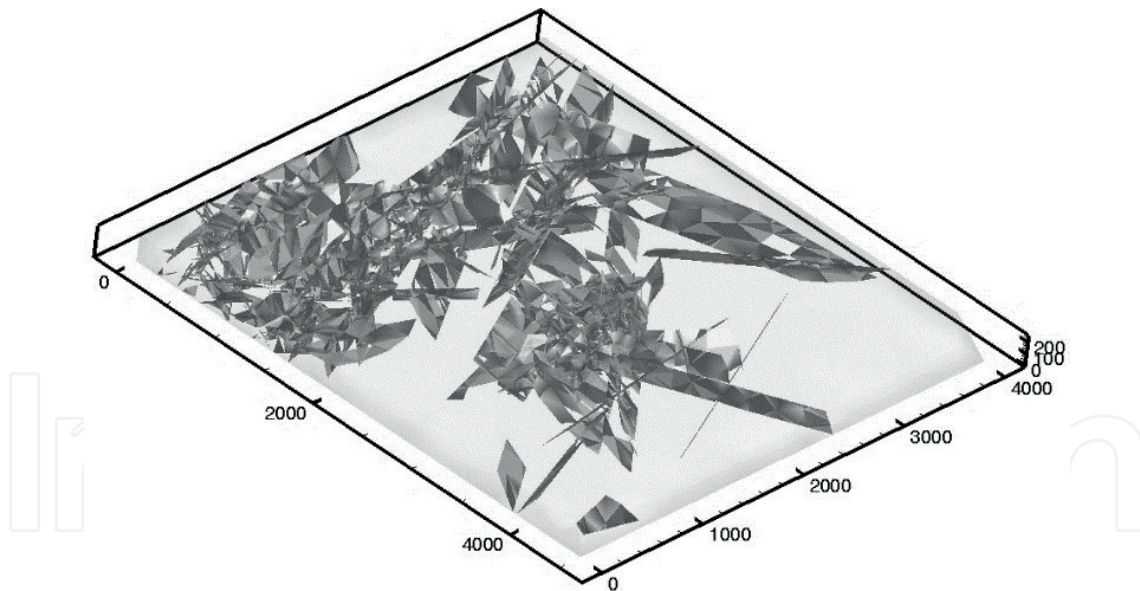


Figure 6. 3D view of fracture network for the studied reservoir.

been accounted for effective permeability tensors and long fractures ($l > 40$ m) are discretized explicitly in the reservoir domain for fluid flow simulation (**Figures 5 and 6**).

The area of the reservoir is 20 km^2 and the average porosity is 5% and OOIP is 1000 MM barrel. The reservoir PVT is collected from PVT report and the initial oil formation volume factor that has been used during the simulation runs was 1.25 rb/STB. The relative permeability curve and capillary pressure used are presented in **Figure 7**.

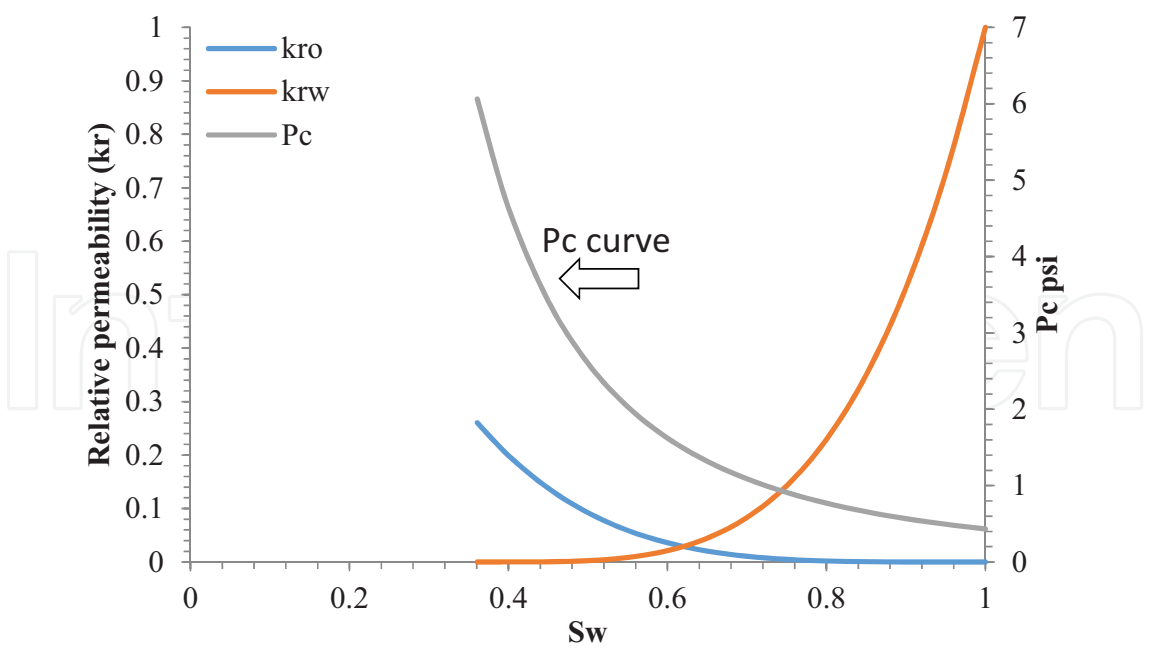


Figure 7. Relative permeability and capillary pressure curves used in simulation of fluid flow.

Parameter	Value
Oil viscosity (cp)	3
Initial Oil formation volume factor rb/stb	1.05
Oil density (lb/ft3)	52

Table 1. Oil physical properties used in simulation model.

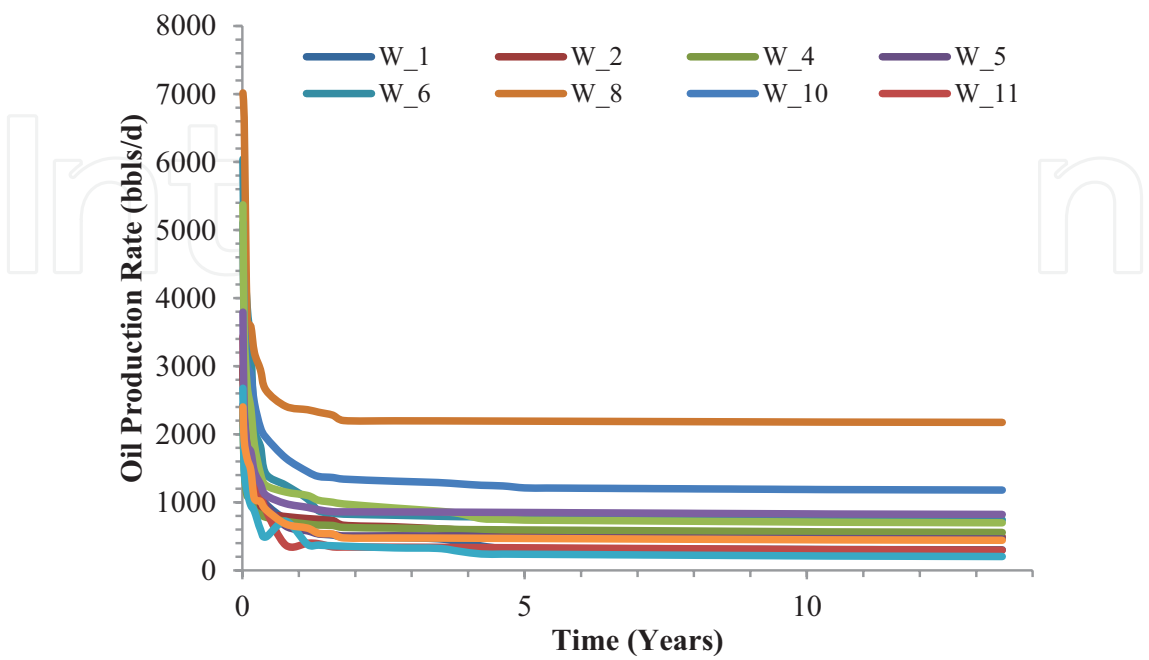


Figure 8. Oil production rate for wells in the studied fractured reservoir.

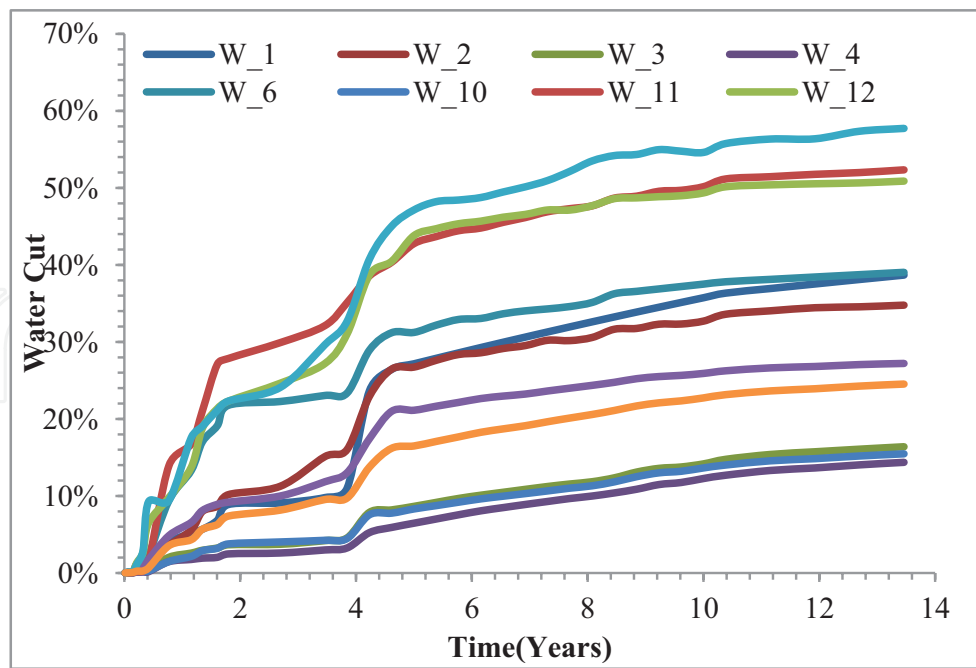


Figure 9. Water cut for wells in the studied fractured reservoir.

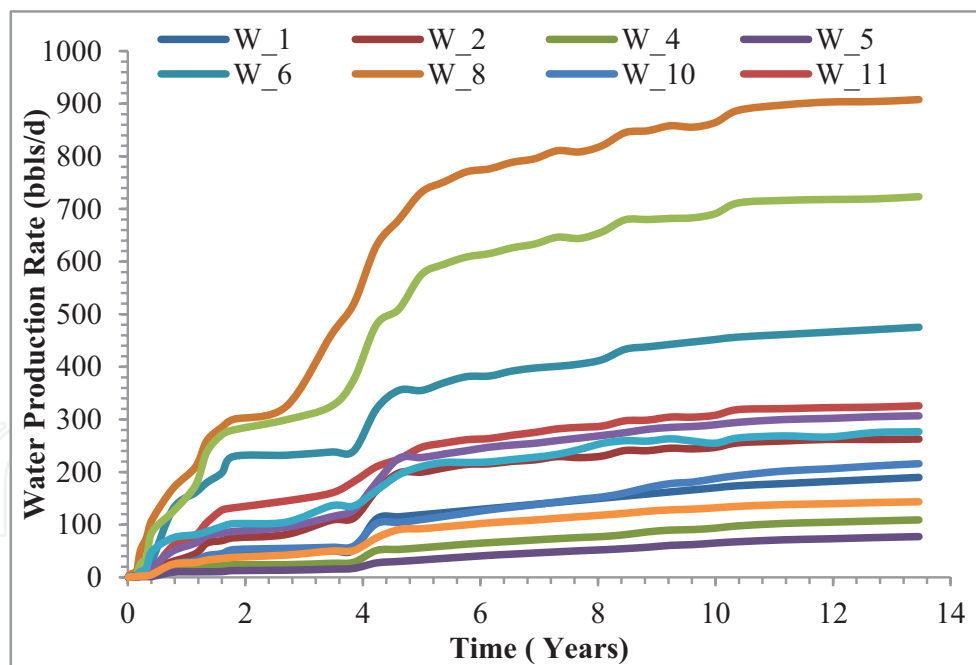


Figure 10. Water production rate for wells in the studied fractured reservoir.

Low salinity water flooding is applied on the studied reservoir to maintain the reservoir pressure and for testing wells production profile under water injection scenario. The fractured reservoir thickness is divided into three zones. The first zone is from 800 to 1100 m is the main production zone. The second zone is from 1100 to 1200 m is a separation between the injection and production zones and the third zone is from 1200 to 1400 m is the injection zone.

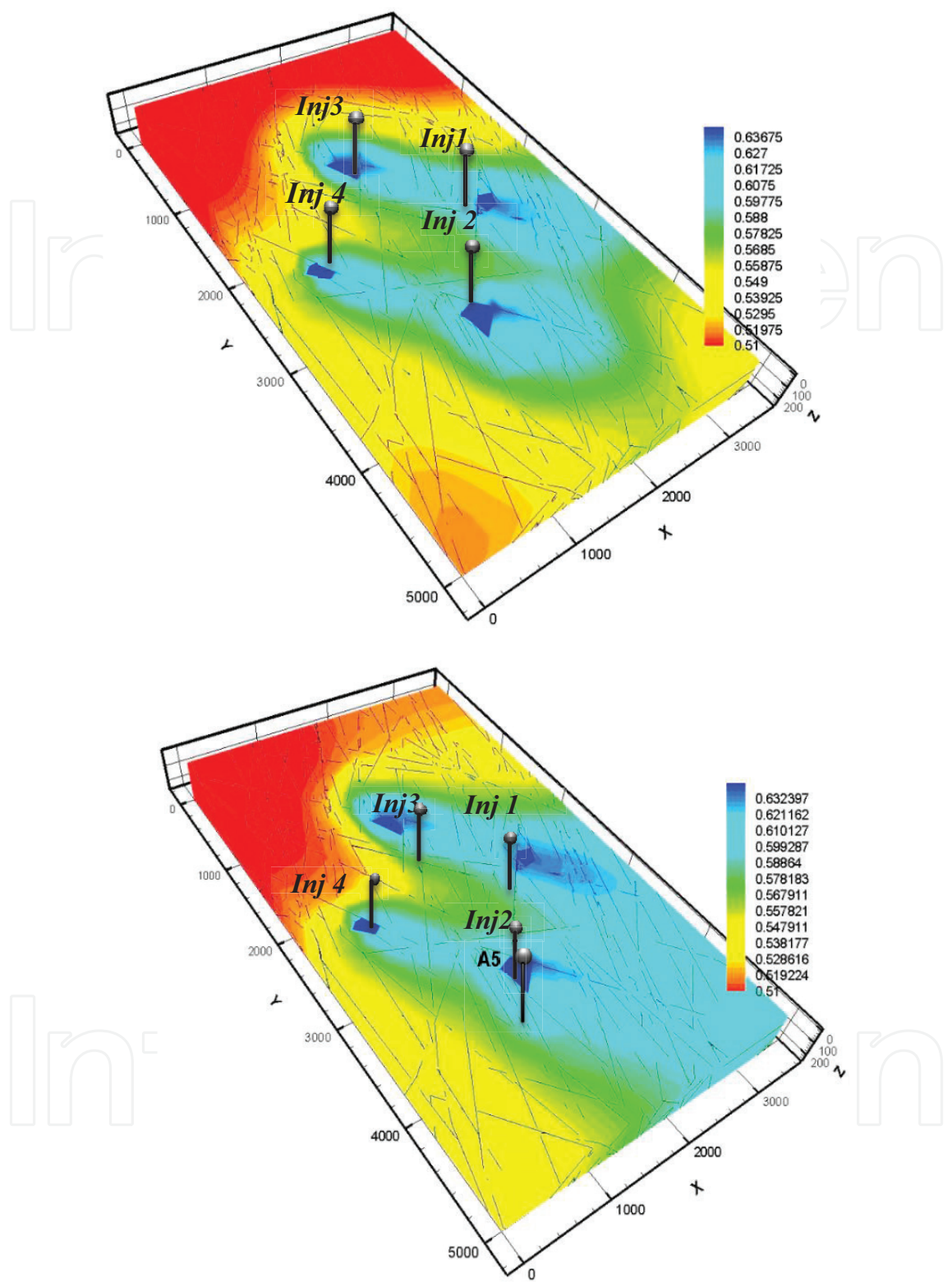


Figure 11. Water saturation profile after five months and 5 years of water injection respectively.

Four injectors were selected in the studied reservoir and are distributed as five spots to displace oil around 12 producers. All the injection wells are vertical and the amount of water injected in each well was 4500 bbls/d. water is injected into the bottom region while the oil was produced from the basement top section.

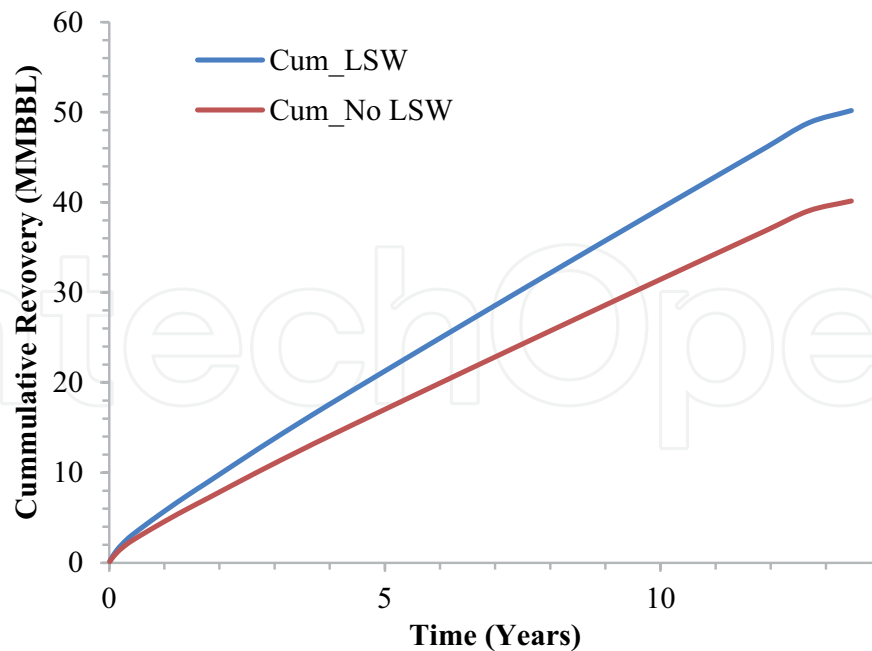


Figure 12. Cumulative oil production rate under conventional and low salinity water flooding.

The reservoir model was a two phase model, containing only oil and water for simplifications. The initial connate water salinity was set to 750 kg/m³ total dissolved salts (TDS) approximately the same salinity as regular seawater, and Brine salt content is 0.25 fraction (Ca²⁺, Mg²⁺, Na⁺, and SO₄²⁻ concentration was observed.).

Table 1 shows oil physical properties.

Figure 8 shows wells water production rate. Well #W_8 has the highest water production rate because of the location of this well is bounded by the four injectors. Well #W_5 has the lowest water production rate because of the location of this well is far from the inaction area. **Figure 9** is showing the water cut at the producers, while **Figure 10** is showing the water production rate for all producers. As shown from **Figure 7**, well #W_8 has highest oil production rate owing to the sweep efficiency in the area surrounded by well #W_8 is very high. **Figure 11** shows the water saturation profile after 5 months and 5 years of water injection respectively.

Figure 12 shows the comparison between the cumulative oil production under conventional and low salinity water flooding for the same fractured reservoir. The presented results at **Figure 12** show that low salinity water flooding process increases the recovery factor after 13 years of water injection by 1.4% which proves that this type of fractures reservoir requires a comprehensive study on how to increase the recovery factor by understanding the mechanisms behind the production process.

8. Conclusion

In this study, we made a comprehensive review on low salinity water flooding and the factors controlling the oil recovery. In addition, simulation of low salinity water flooding performed

on a fractured reservoir located in Arab region. The simulation was based on a finite element technique a hybrid mode of using permeability tensors for low and short fractures and discretization of long fractures explicitly inside the reservoir domain. In which, the presented technique eliminate the use of dual porosity model as this technique does not consider fluid distribution within the matrix blocks during the simulation period and only can be applied for small number of large scale interconnected fractures. The simulation of low salinity water flooding in this study strongly based on wettability change. The results show that the recovery increases significantly by using injected brine volume.

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