Hybridization of Low Salinity Water Assisted Foam Flooding in Carbonate Reservoir for Enhanced Oil Recovery

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Abstract

Low salinity water injection (LSWI) and foam flooding hybridisation are recent advances in enhanced oil recovery (EOR) techniques where water of a lower salt concentration than the initial connate water and foam is injected into the reservoir respectively. Although a lot of field and laboratory experiments have shown that standalone LSWI and foam flooding improve oil recovery, there has not been many numerical modelling studies carried out with regards to hybridising both techniques. In this study, the main mechanism for these two methods were investigated through simulations of a 3-dimensional synthetic carbonate reservoir model using ECLIPSE 100 software. The carbonate model is homogeneous with water, oil and gas phases present. LSWI and foam flooding was created as standalone models compared to the hybridised models. The first hybridised model is low salinity water alternating foam (LSWAF) injection, the second model is simultaneous injection of low salinity water and foam (SLSWF) and the last model is selective simultaneous injection of low salinity water and foam (SSLSWF). It was an established mechanism that, LSWI and foam used in the hybridised models delayed early water breakthrough as a result of wettability alteration. Results showed that the altered hybridized models led to higher recovery efficiency and insignificant water cuts than the standalone models. Also, the SLSWF model is considered as the best EOR technique since it led to the highest recovery efficiency of 58.58%, followed by SSLSWF of 58.45% and LSWAF of 47.79% for ten years production period. Finally, the combination of LSWI and foam provided the best means of EOR than the standalone techniques in the carbonate reservoir.

Keywords: Water Cut, Foam, Numerical Modelling, Low Salinity Water Injection, Wettability Alteration

1 Introduction

EOR is another strong growing area that recovers the substantial amount of oil remains in the reservoir after primary and secondary recovery methods are exhausted (Dankwa, 2019). EOR is of increasing interest due to the high fluctuations in oil prices, higher demand of crude oil and the need to increase production. Gas flooding involves the injection of gas to recover more oil from the reservoir. These gases are less dense than the in-situ reservoir fluids and hence the gases tend to bypass the oil (viscous fingering and gas channelling) leading to low sweep efficiency (*et al.*, 2018a). Because of this, foam flooding as an EOR technique has been used for mobility control in gas flooding to improve sweep efficiency (Krause *et al.*, 1992).

LSWI is one of the most emerging chemical enhanced oil recovery (CEOR) techniques (Brantson *et al.*, 2019). LSWI has been carried out in the field with evidence of improvement in oil recovery with subsurface problems such as viscous fingering and water channelling leading to early water breakthrough (Brantson *et al*., 2018b). But the petroleum industry is now appreciating new hybrid methods that combines two or more different EOR methods in order to improve oil recovery.

Many researchers have examined the effects of interactions between crude oil and foam with more attention being given to the negative effects of these interactions (Rashed *et al.*, 2014). Whenever oil comes into contact with foam, the oil tends to have a destabilizing effect (Anti-Foam) (Nell, 2015; Schramm, 2010). Therefore, the best way to overcome this problem is to change the wettability of the reservoir rock using a hybrid EOR technique. Wettability alteration has recently gained more attention for carbonate formations as compared to sandstone formations for the fact that, carbonate formations are likely to be more oil-wet (Treiber *et al*., 1992).

The existing literature has also shown that hybrid methods have many advantages for increasing oil recovery (Janssen *et al*., 2019). Researchers have experimentally investigated the effects of wettability alteration for increasing oil recovery, but to the best knowledge of the authors, the numerical simulation of low salinity water assisted foam flooding (LSWAF) in carbonate reservoirs with different injection techniques has not been reported in the literature. Therefore, this paper, for the first time seeks to numerically simulate a hybrid of LSWAF to improve oil recovery in carbonate reservoir.

1.1 Carbonate Reservoir

A reservoir is a subsurface volume of porous and permeable rock that has both storage capacity and the ability to allow fluids to flow through it.

Carbonate reservoirs are usually created in marine sedimentary environments with little or no clastic material inputs (biogenic origin). They are extremely important because they have the ability to create very effective secondary porosity through diagenetic changes such as dolomitization, fracturing, dissolution and recrystallization. It is the least most abundant sedimentary rock (Anon, 2001). Despite being the least abundant sedimentary rock, it is also the sedimentary rock with a lot of produced hydrocarbons (Anon, 2001).

Carbonates are sediments formed by a mineral compound characterized by a fundamental anionic structure of CO_3^{2-} . Calcite and aragonites ($CaCO_3$) are examples of carbonates. Limestones are sedimentary rocks consisting mainly of the mineral calcite (calcium carbonate, $CaCO_3$), with or without magnesium carbonate. Limestone is the most essential and abundant of the carbonate rocks.

Dolomite is also a common rock forming mineral with the formula $CaMg(CO_3)_2$. A sedimentary rock will be named dolomite if that specific rock is composed of more than 90% mineral dolomite and less than 10% mineral calcite.

1.2 Low Salinity Water Injection (LSWI)

After the natural depletion of the reservoir, water injection is the most common improved oil recovery (IOR) method. Usually, the produced formation water is injected back into reservoir for sweeping oil and maintaining pressure in the reservoir. Moreover, laboratory experiments and field applications of low salinity water flooding (LSW) can lead to significant reduction in residual oil saturation and as such, there has been a growing interest with an increasing number of LSWI studies.

LSWI was much appreciated when Reiter (1961) discovered an increase in oil production due to manipulation of the salinity water injected. Bernard (1967) showed the increasing oil recovery after conducting experiment, where the salinity was reduced by 14 900 ppm (15 000 ppm to 100 ppm) in the injection brine. After that, researchers began to focus on the salinity of injected brine, until Tang and Morrow (1999) offered the first theoretical interpretation of the mechanism responsible by a great number of laboratory tests (Tang and Morrow, 1999; Zhang *et al*., 2006).

Apart from the increasing amount of laboratory experiments that were published in the last decade, several field trials have been carried out to test the potential of LSWI for improving oil recovery at the field scale. For instance, LSWI has been conducted on BP's Endicott field in Alaska with evidence of 6-12% increase in oil recovery (Lager *et al*., 2008). Also, comparative studies have been conducted between high salinity waterflooding (HSWF) and LSWI in the Omar Field of Syria. It has been reported that, LSWI has about 5-15% increase in oil recovery as compared to HSWF (Vledder *et al*., 2010; Gao *et al*., 2014). The log-inject-log test (Webb *et al*., 2003) examined 25-50 % reduction in residual oil saturation when applying LSWI.

1.3 Foam Flooding

Foam flooding is a CEOR method used to improve sweep efficiency during gas injection. In addition, foam may increase the oil plateau production period for matured oil fields by reducing the gas-oil ratio for wells suffering from high gas production. Perhaps its most attracting application is to offer the best hope for mobility control in gas flooding suffering from poor volumetric sweep efficiency due to the displacement front instability and early breakthrough caused by the undesirable gravity segregation and viscous fingering (Chen *et al*., 2005). In earlier literature, it was only found that two reported field applications of foam were to reduce gas production in production wells (Krause *et al*., 1992; Heuer *et al*., 1968).

Foams, a unique type of colloidal dispersion, usually refer to a system in which a gas phase is dispersed in a continuous liquid phase (Gauglitz *et al*., 2002). As a result of its unique flowing and rheological properties, foam has been widely used as drilling fluid, fracturing fluid and acidizing fluid in the petroleum industry over the few decades (Bernadiner *et al*., 1992). Through introducing foams into the oil reservoir, no matter whether the foam is pre-generated or not, the gas relative permeability will be significantly reduced. Meanwhile, the high permeability zone is preferably blocked by the foam, significantly alleviating the reservoir heterogeneity. Thus, foam EOR process can take place in the low permeability zone (carbonate reservoir) which otherwise would be bypassed in a conventional gas flooding.

A great number of laboratory and numerical investigations have been performed to approve the effectiveness of the foam flooding worldwide in recent years (Wang *et al*., 2011; Haugen *et al*., 2014; Ebrahimi *et al*., 2016). A typical field application of foam flooding is Foam Assisted WAG which was tested in the Snorre field in the Norwegian North Sea (Awan *et al*., 2008) which was purposely used as a gas mobility control by alternating slugs of gas with slugs of surfactant solution. In depth analysis of field applications of foam in EOR projects show that the main problems encountered during field-scale foam applications are related to foam stability (Ibrahim and Nasr-El-Din, 2019), foam compatibility, as well as adsorption of the injected chemicals onto the rock surface.

1.3.1 Effect of Oil on Foam Stability

It is well known that when foam comes into contact with crude oil, it adversely affects the foam stability (Nell, 2015). This is because foam is a closed system, and the oil reaches only the outer surface of the foam. The defoaming activity of oil (or other defoamers) is usually explained in terms of the effects resulting from the surface activity of the oil or de-wetting of the oil by the aqueous solution. This in turn depends on several physical and chemical properties.

1.5 Hybrid EOR Methods

In recent years, advances in EOR projects have led to the implementation of hybrid methods (combining two or more EOR methods) with evidence of increasing oil recovery. Several researchers have examined the potential increase of oil recovery by hybrid EOR methods. For instance, a hybrid of foam and CEOR (Janssen *et al*., 2020) Alkali/Surfactant/Polymer (ASP) flooding has been reported to increase oil recovery in the Tanner field (Pitts *et al*., 2006) and also in the Viraj field of India (Pratap *et al*., 2004). Not limiting the field application of hybrid methods, experimental works showed the combination of low salinity water and foam led to an increase in recovery in sandstone reservoirs (Shabib-Asl *et al*., 2018). Since hybrid methods have been proven to increase oil recovery in sandstone reservoirs, the oil recovery rates of standalone low salinity waterflood and foam flooding will be compared. Lastly, a hybrid of low salinity waterflood and foam flood in carbonate reservoir was numerically simulated.

2 Resources and Methods

2.1 The Geologic Model

Geological model is a spatial representation of the distribution of sediment and rocks in the subsurface. The geologic model used for this project was built using a simple Cartesian (block-centred) grid system of the Eclipse 100 software (Schlumberger, 2013). The black oil simulator in Eclipse was used for all the models built in this study. Data used for the all the models was obtained from a published Schlumberger note on Chemical EOR (Schlumberger, 2009). Each of the various models had dimensions of 20×40×3 in the *X*, *Y* and *Z* directions, respectively and was discretized into 2400 cells as shown in Fig. 1.

2.2 Low Salinity Water Injection (LSWI): Options in ECLIPSE 100

Eclipse has a brine tracking function for enabling either the low salinity option or the high salinity option. Low salinity option can be activated in the RUNSPEC section using the LOWSALT keyword.

The LSWF model has 20 cells measuring 100 ft in the X- direction, 40 cells each measuring 100 ft in the Y- direction and 3 layers with each cell measuring 20 ft in the Z – direction. The black oil model was used in this model with the reservoir containing live oil (the reservoir contains water, oil, gas and dissolved gas) with the foam tracking function. PVTO and PVDG were specified in this model. An aquifer (Fetkovich aquifer) was also present in this model. The reservoir is located at the depth 8 325 ft sub surface.

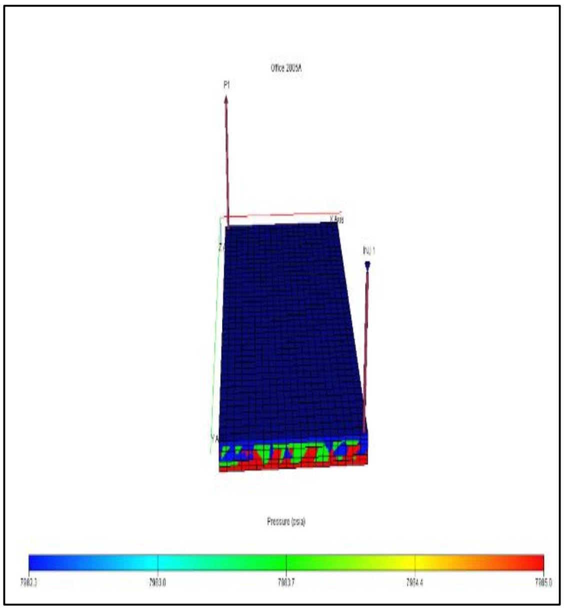

Fig. 1 The Geologic Model

For initialisation purposes to determine the state of the reservoir fluids at initial conditions when the production well has not started producing yet, the EQUIL keyword was specified such that the pressure at the datum depth is 8 000 psia, the water-oil contact is at 8 500 ft with a zero oil-water cap pressure. Also, the gas-oil contact was at 8 200 ft. An aquifer was specified using the keyword AQUFETP (Fetkovich aquifer) with its respective connections with the reservoir (AQUANCON).

The model has one producer which was modelled in the schedule section using the keywords WELLSPECS, COMPDAT and WCONPROD. There is one injector which was also modelled using the keywords WELLSPECS, COMPDAT, WCONINJE and WSALT which was used to specify the concentration of salt injected. The WCONPROD control was the Oil Rate (ORAT) where it was set to 50 000 stb/day. With the injection well, water of salt concentration of 2 lb/stb was injected right from day one of the simulation. The WCONINJE control type was the Bottom Hole Pressure (BHP) where a target of 5 000 psia was used. The simulation advanced for 10 years.

2.3 Foam Flooding: Options in ECLIPSE 100

Foam model is activated in ECLIPSE in the RUNSPEC section using the FOAM keyword.

This model just like the model for low salinity waterflood had the same dimension and grid sizes in all directions. The black oil model was used in this model with the reservoir containing live oil (the reservoir contains water, oil, gas and dissolved gas) with the foam tracking PVTO and PVDG was specified in this model. An aquifer (Fetkovich aquifer) was also present in this model. The reservoir is located at the depth of 8 325 ft sub surface.

At the initialisation section to determine the state of the reservoir fluids at initial conditions when the production well has not started producing yet, the EQUIL keyword was specified such that the pressure at the datum depth is 8 000 psia, the water-oil contact is at 8 500 ft with a zero oil-water cap pressure. The gas-oil contact depth was 8 200 ft with zero cap pressure. Aquifer was specified using the keyword AQUFETP (Fetkovich aquifer) model with the respective connections with the reservoir. This was to help initialised the various fluids in the reservoir as well as knowing their specific amounts in-place. This was used to quantify the initial oil place, gas in place and the equilibrium nature of the fluids once production has not yet started.

Just as the LSWI model, the producer's oil rate was set to 50 000 stb/day. Also, with the injector, the keyword WFOAM was used to specify the foam concentration which had value of 1.1 lb/stb was assigned right from day one of the simulation. The control BHP target for the injector was set to 5 000 psia. The simulation proceeded for 10 years.

2.4. Hybrid of Low Salinity Water and Foam Flooding (LSWAF)

The model also has 20 cells each measuring 100 ft in the X- direction, 40 cells each measuring 100 ft in the Y- direction and 3 layers with each cell measuring 20 ft in the Z – direction. The reservoir is located at the depth 8 325 ft sub surface.

For basic reservoir properties, this model had same dimensions, grid block sizes, porosity and permeability just as that of the other two models. The reservoir fluid contains water, oil, gas and dissolved gas with both the brine (LOWSALT) and foam tracking functions (FOAM). An aquifer model was incorporated into this model and a live oil PVT data was used in the modelling.

For initialisation purposes to determine the state of the reservoir fluids at initial conditions when the production well has not started producing yet, the EQUIL keyword was specified such that the pressure at the datum depth is 8 000 psia, the water-oil contact is at 8 500 ft with a zero oil-water cap pressure. The gas-oil contact depth was 8 200 ft with zero cap pressure. The aquifer was specified using the keyword AQUFETP (Fetkovich aquifer) models with the respective connections with the reservoir. This was to help initialise the various fluids in the reservoir as well as knowing their specific amounts in-place. This model also has one producer and one injector which salt concentration of 2 lb/stb and a foam concentration of 1.1 lb/stb was introduced into the reservoir.

2.5 Ways of Hybridising LSWI and Foam Flooding

2.5.1 Hybrid Low Salinity Water Alternating Foam (LSWAF)

This method employs the initial injection of foam. After four years, low salinity water was injected after two years and subsequently injecting foam after the injection of the low saline water. The producer's oil rate was set to 50 000 stb/day. With the injection well, foam of concentration 1.1 lb/stb was injected right from day one of the simulation until the fourth year. Also, low salinity water of concentration 2 lb/stb was injected for 3 years following the injection of the foam and lastly foam was injected for another 3 years after the injection of the low salinity water through the same injection well.

2.5.2 Simultaneous Low Salinity Water and Foam (SLSWF)

This type of hybridisation involves the injection of the low salinity water and the foam at the same time. In this case, foam and low salinity water was injected into the same injector at the beginning of the simulation. The producer's oil rate was set to 50 000 stb/day. With the injection well, low salinity water of concentration 2 lb/stb and foam concentration of 1.1 lb/stb was injected through one injector right from day one of the simulation till the end of the simulation.

2.5.3 Selective Simultaneous injection of Low Salinity Water Alternating Foam (SSLSWF)-Dual Completion Technique

This is when a well (production well in this case) that simultaneously drains two reservoirs of oil or gas at different depths with production from each zone separated by tubing (Anon, 2020). This was a clone case of the simultaneous model just that the vertical well was completed in two different layers rather than just a single layer to produce oil from all these zones. With the help of the COMPDAT keyword, this was possible to complete the well at zones 1 and 2 of the model.

3 Results and Discussion

3.1 Main Mechanisms of LSWAF

Wettability is the main mechanism that drives the consideration of LSWAF. Wettability is the ability of a fluid to adhere to a solid surface in the presence of other immiscible fluids (Anon, 2020). With the LSWI model, the main mechanism was the exchange of cations. By injecting low salinity brine, it allows monovalent ions such as sodium (Na^+) from the injected low salinity water to displace divalent ions such as Mg^{2+} and Ca^{2+} which are present in the formation water.

Furthermore, the carbonate ($CaCO_3$) rock surface has a positive charge when the pH is less than 9.5 (when dissociated). In low salinity waterflooding, pH is a measure of the concentration of H^+ ions and OH^- ions in brine. Low salinity water splits into hydrogen ions (H^+) and hydroxyl ions (OH^-) which is responsible for the pH.

H_2O — $H^+ + O^{2-}$

CaCO3 — $Ca^{2+} + CO_3^{2-}$

The dissolution renders the carbonate rock surface positive. When oil and water occupy a pore, the negative charge of the component of oil attracts $RCOO^-$ molecules to the carbonate rock surface to make the rock oil wet. Therefore, the carbonate wettability change from oil-wet to water wet with similar findings also obtained by Hassan *et al.* (2019).

Moreover, with the foam flooding, the main mechanism was the decrease in mobility of the injected gas. After its injection into the reservoir at an adequate composition, foam changes the wetting characteristics of the carbonate reservoir thus favouring oil recovery.

The mechanism of LSWAF was established since foam is a gas, by the concept of gravity, it is found on top of the low salinity water. This mechanism helped to prevent early breakthrough of the low salinity water due to stable foam film. This wettability alteration process can also be inferred from Fig. 2 relative permeability curves

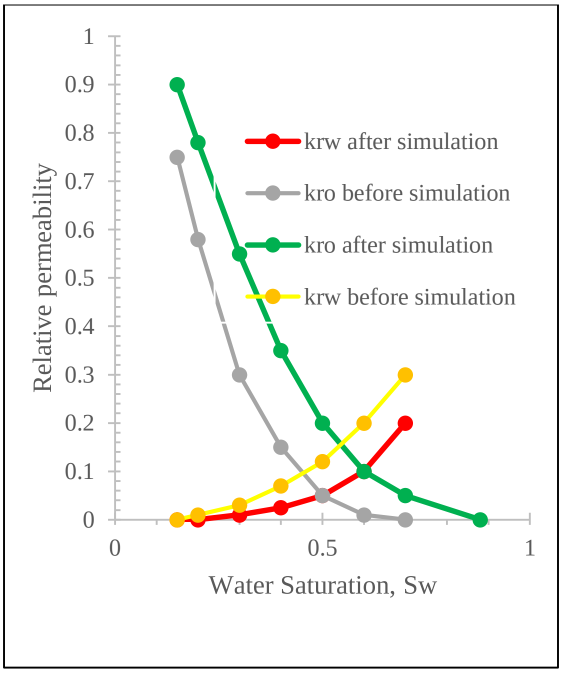

Fig. 2 Relative Permeability Curves Before and After Simulation.

3.2 Field Oil Recovery (FOE)

FOE is the amount (in percentage) of oil recovered from the reservoir at the end of the simulation (by the end of its producing life). After simulating all the models, it was found that SLSWF model is considered as the best EOR technique since it led to the highest recovery efficiency of 58.58%, followed by SSLSWF of 58.45% and LSWAF of 47.79% for ten years production. Also, the foam model had a recovery factor of 32.31% and lastly the low salinity model with the least (17.96%) as shown in Fig. 3.

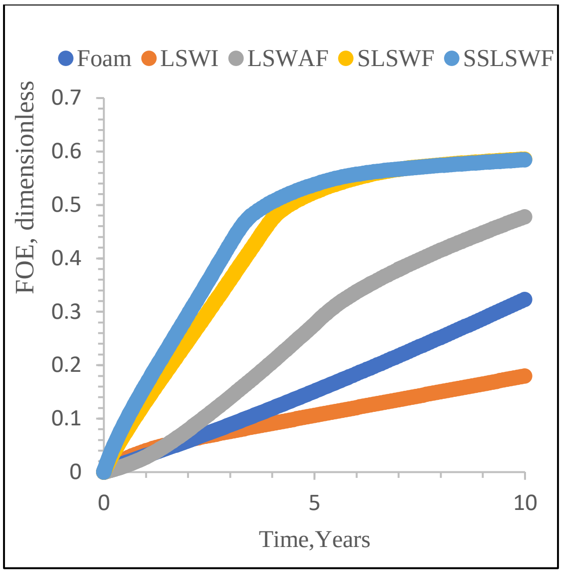

Fig. 3 Comparison Between FOE for the Various Models

3.3 Field Oil Production Total (FOPT)

The total oil recovered from the various models are shown in the Fig 4. From the figure, in all cases, the hybridized models recovered the most oil than the two standalone models (foam and low salinity model). However, the foam model also recovered lots of oil than that of the low salinity oil.

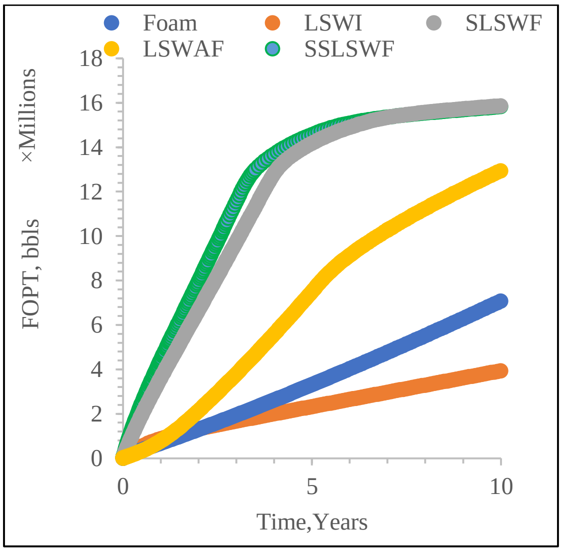

Fig. 4 Comparison of FOPT for the Various Models

Table 1 Concentrations of Salts Used

Model / Salt Concentration	Foam	Low Salinity	Hybridised Models	Unit
Initial Concentration	9	9	9	Ib/STB
Injected Concentration	0	2	2	Ib/STB

3.4 Field Oil Production Rate (FOPR)

Production rate is the volume of produced fluid per unit of time. From Fig 5, the production rate for all the models kept decreasing as time progresses except for the LSWAF. With the LSWAF, the oil production rate kept fluctuating until the final five years before finally the constant decline rate.

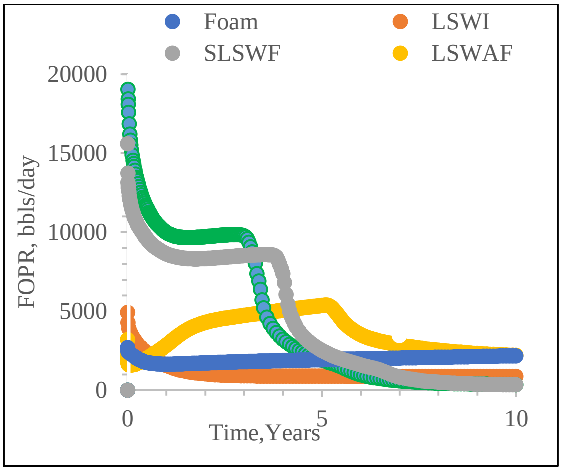

Fig. 5 Comparison Between FOPR for the Various Models

3.5 Field Pressure (FPR)

Pressure of a reservoir keeps declining as production begins. From Fig 6, the pressure of the foam model declined rapidly in the first two years of simulation. It was almost impossible to continue producing at the initial rate and thus, the control rate was changed to BHP (5 000 psia) to keep up with the rate at which the reservoir pressure declined and to prevent the reservoir from losing all of its energy. This action increased the pressure in the reservoir till the end of the simulation.

The pressure for the low salinity model declined rapidly in the first two years but the pressure was maintained above 2 000 psia for the rest of the simulation time. This was possible because of the low salinity water injected which served as a means of pressure maintenance as well as an enhanced oil recovery technique and wettability alteration.

The pressure for LSWAF model declined significantly after the fifth year when low salinity was injected into the reservoir. This action decreased the reservoir pressure for the rest of the simulation period.

With regards to the SLSWF, its pressure kept declining until the end of the first simulation year. The reservoir pressure was declining so rapidly that, the Control Mode of the production well was changed to BHP. This further increased the pressure in the reservoir until the fifth year and finally decreasing. Since the SSLSWF is a clone case of SLSWF, it exhibited a similar trend in the pressure profile during the simulation.

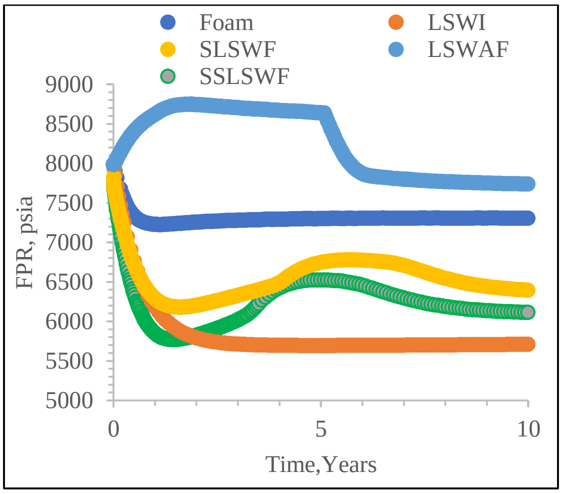

Fig. 6 Comparison Between FPR for the Various Models

3.6 Field Water Cut (FWCT)

This is the ratio of the water which is produced in a well compared to the volume of the total liquids produced (Brobbey, 2018). In this work, the water cuts are negligible. The foam model had the highest water cut which was low (0.25%) and that of the LSWI model had a water cut which was also very low (0.19%) as shown in Fig 7. The hybridised models had less or insignificant water cut. The low water cuts could be attributed to the large spacing between the injector and the producer and also wettability alteration

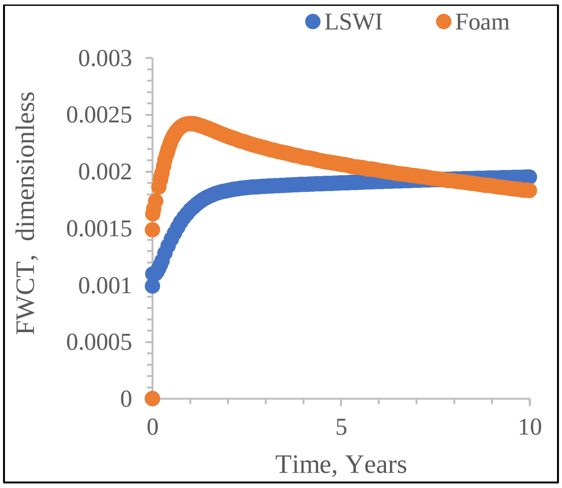

Fig. 7 Comparison Between FWCT for the Various Models

4 Conclusions

The following conclusions were drawn from the study:

i. Oil production, field oil recovery, production totals with the hybridized models were higher than the standalone models. Nevertheless, the foam model proved to yield more oil as compared to the LSWI model;
ii. It can also be concluded that, in all scenarios, the hybridised models provide the best means of pressure lifting in the reservoir;
iii. The hybridised models produced less water to take care of the disadvantage of the individual models with respect to water production; and
iv. The mechanism of LSWAF was established to be wettability alteration and stable foam film in the presence of reservoir conditions. Since foam is a gas, by the concept of gravity, it is found on top of the low salinity water. This mechanism helped to prevent early breakthrough of the low salinity water.

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