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Improved Oil Recovery by Polymer, Surfactant and Low Salinity Water Flooding Applied for Gullfaks field (Statfjord-I1 Segment) Based on applied Reservoir Simulation.

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AMRAN OMAR FAKIH

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ABSTRACT.

Most of the energy used all over the world come from fossil fuels. Recently, large part of which comes from hydrocarbons and most part of hydrocarbons fields are matured. As the demand for energy is increasing , more IOR methods including chemicals injections to recovery the amount of oil remained in the reservoir after primary and secondary phases has to be applied.

This work is based on reservoir simulation to improve the oil recovery of the Gullfaks field (Statfjord I-1 segment) by applying various IOR methods including basic water flooding, chemical injection which involved surfactant, polymer and low salinity water flooding.

The simulation from the base case with three wells, two producers (C-16 and A-36) with one injector (A-41), resulted into the recovery factor of 37.89% from May 1992 to January 2001. When the production time was extended up to 2032, the base case attained a maximum recovery factor of about 46.39%. Low salinity was applied as a secondary method to the base case, the recovery factor was observed to increase from 37.89% to 40.10%.

New case with five wells (three producers and two injectors) was proposed, and the simulation was performed up to 2035, oil recovery of about 64.79% was achieved which is significantly improved compared to the base case.

Polymer and surfactant injection were implemented from the proposed case for a duration of 15 years, unfortunately a minor effect on the oil recovery was observed. The observed improvement in the oil recovery factors were about 0.2% and 0.1% by surfactant and polymer injection respectively. This alternative was therefore rejected, and the low salinity method which was observed from the base case to provide improvement in the oil recovery was adapted.

Low salinity water flooding technique with various salt concentrations from 500ppm to 30000ppm were implemented as secondary and tertiary method. In all these cases significant improvement in oil recovery was observed compared to waterflooding and other chemicals applied . Based on simulation results of oil recovery, incremental oil and gas produced and NPV analysis, low salinity waterflooding has been proposed as the best IOR method for Statfjord I-1 segment .

As part of recommendation further studies including other chemical injection such as alkaline flooding, assisted surfactant polymer flooding (ASP), surfactant injection in salt water and other methods with appropriate reservoir and fluid data from the respective field is very important.

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Dedication

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CHAPTER 1

1.0 INTRODUCTION.

1.1 Oil Recovery Mechanisms.

Production of oil from the reservoir is normally fall into three phases which are primary recovery phase, secondary recovery phase and tertiary recovery phase (Shiran, 2014). Based on the reservoir and fluid properties water flooding which is the secondary recovery method can be applied from the beginning of the production to maintain the reservoir pressure if the initial reservoir pressure is declining very quickly. In some cases, such as extra heavy oil reservoir, tertiary recovery methods (mostly thermal injection methods) is applied from the beginning of production in which case it will be as a primary stage (Lake, 1989).

1.1.1 Primary drive mechanisms.

Recovery of oil from the reservoir to the surface by any natural drive mechanisms is termed as primary recovery (Lake, 1989). (Ahmed, 2006) defined the primary recovery method as the recovery of oil from the reservoir by any natural drive mechanisms, the method doesn’t involve the application of any fluid injection to increase the energy of the natural existing drive. The recovery factor at this stage is less than 30%. (Ahmed, 2006)

Forecasting the future performance of the reservoir and understanding of the behavior of the reservoir requires the knowledge of the reservoir driving mechanisms in which the reservoir fluids are controlled. This is mostly determined by the nature of the reservoir energy presence for pushing the oil to the wellbore. Water influx, gas cap drive, gravity drainage drive, depletion drive and Rock and liquid expansion drive are the basic drive mechanisms which fall into primary drive methods (Ahmed, 2006). Sometime combination drive occurs in a reservoir (example water and gas cap drive).

1.1.2 Secondary drive mechanisms.

Secondary recovery is the method in which fluids such as water or gas are injected into the reservoir with the intention of maintaining the reservoir pressure. Water flooding is the most common secondary recovery technique in which water is injected into the reservoir and displaces the oil to the production well. In this case the injected water increases the reservoir energy of the system (DAKE, 1978). The recovery factor at this stage is up to 50% (Ahmed, 2006).

1.1.3 Tertiary drive techniques.

These methods are applied after implementation of primary and secondary recovery techniques. They are mostly applied to recover residual oil remained behind after both primary and secondary methods to attain their economic limits (Ahmed, 2006). Processes such as miscible gases, chemicals and thermal energy are used at this stage to recover the remained oil. The recovery factor at this stage can rise up to 12% compare to the one achieved by primary and secondary methods. Figure 1 describe the three oil recovery methods.

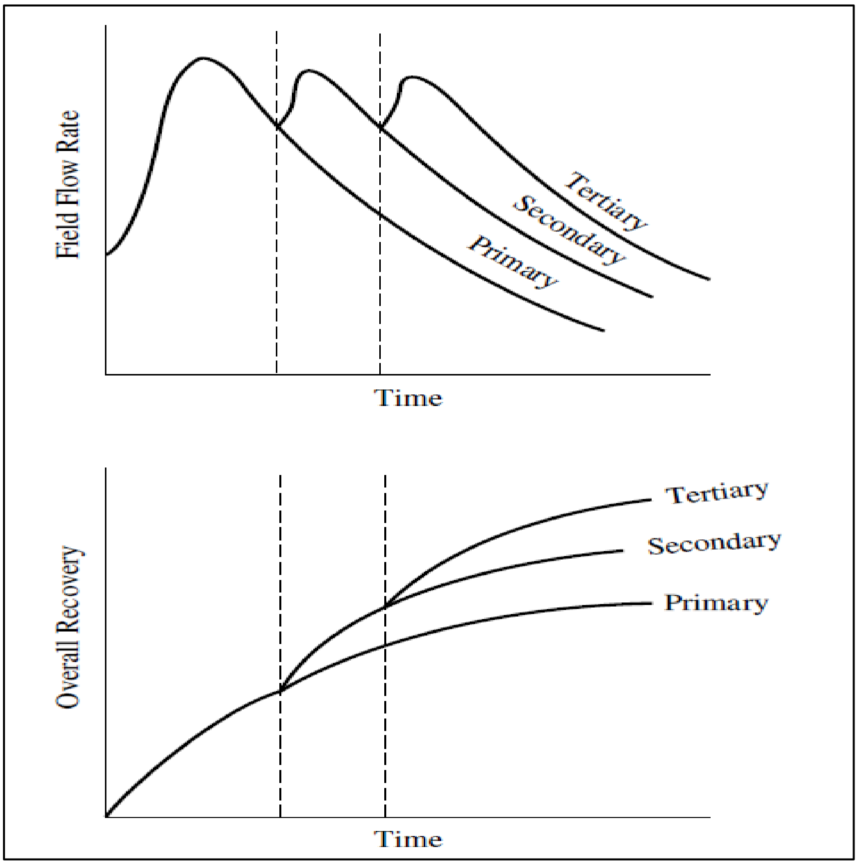


Figure 1:Description of oil recovery techniques (Ahmed, 2006)

1.2 Improved Oil Recovery (IOR) & Enhanced Oil Recovery (EOR).

Improved Oil recovery involves any measure taken to improve the recovery of oil. Such measures include infill drilling, well location (placement) optimization, Reperforation, Horizontal wells, hydraulic fracturing, secondary drive mechanisms (waterflooding including various pressure maintenance methods) and Enhanced oil recovery (EOR) techniques are IOR methods (Alvarado & Manrique, 2010) as seen in figure 2. EOR is sometime related to IOR but in real case IOR is a broad term in which EOR can be considered as a subset within IOR methods.

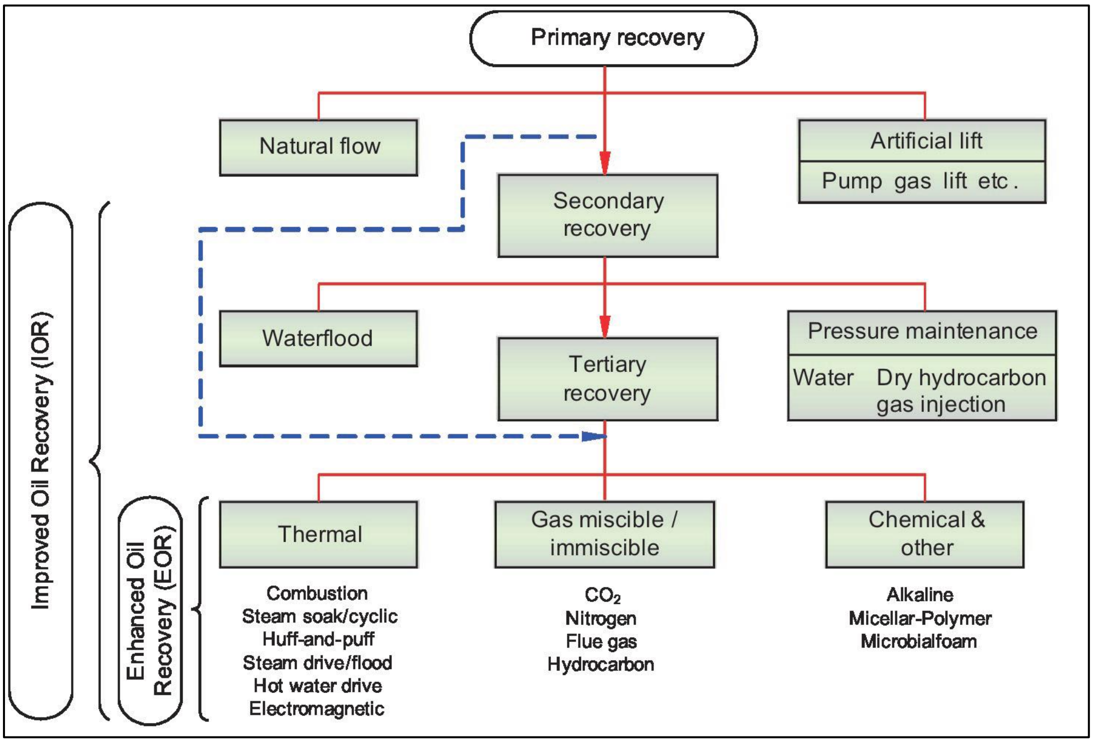


Figure 2:Description of IOR and EOR Methods (SEČEN, 2005).

To keep the reservoir pressure above the bubble point, waterflooding has been applied at the Gullfaks field from the starting of production since the pressure was declining very quick. Although water flooding has shown a great success in the recovery of oil in Gullfaks field, still there are areas with oil remaining unswept. As a result, more improved oil recovery methods have been applied to recover the amount of oil which was not recovered by water flooding. (Talukdar & Instefjord, 2008).

Gas injection was also applied at Gullfaks field to add more energy after the decline of natural drive, unfortunately gas injection was not suitable for the reservoir hence it was stopped soon after showing that it was not suitable for the field. (Talukdar & Instefjord, 2008)

Various seismic data have been acquired and the analysis of the 4D data has proven that there is significant amount of oil remained behind during water flooding, which lead to further study of the reservoir properties and different IOR methods to be applied.

Some IOR methods such as infill drilling, horizontal well, reperforation and the application of some chemical injection have been implemented. Most of the methods have proven successful and other are still under experimental test to be applied this include low salinity water flooding and polymer flooding. (StatoilHydro, 2007).

1.3 Problem Statement

Gullfaks field has been in production since 1986, as a result of low reservoir pressure water injection has been applied from the beginning of the production to keep the reservoir pressure above the bubble point. To date the recovery factor of Gullfaks field is about 56% (Talukdar & Instefjord, 2008). Water flooding has proven to be the best IOR methods for the field due to many factors such as availability, it is cheap, and is easy to handle the used water after at the surface facilities.

Although oil has been recovered up to 56% by water flooding, normally there is a need to improve the sweep efficiency of the system so that more oil may be recovered from the reservoir. To achieve this some of the properties of the reservoir system such as wettability, capillary pressure, viscosity of the displacing fluids and relative permeabilities must be changed so that the necessary conditions for improving sweep efficiency is attained. Residual oil (oil which has been left behind by water flooding) has been observed when studying the reservoir model of the field in which case the time for other IOR methods such as polymer, surfactant and low salinity water injection has to be considered.

Some of these IOR methods has been put in test at small scale (core flooding in laboratory level). The consequences have been reported to be positive for some of them and some of them have shown non-economical results.

This work aiming at performing simulations of these IOR methods for Gullfaks field (Statfjord-I1 Segment), carry out the economic analysis and compare their results based on the oil recovery factor and the economical basis. Then the best option will be proposed for the field.

1.4 Objectives

1.4.1Main Objective:

The main objective of this work is to evaluate effectiveness of the three IOR methods (polymer, surfactant and low salinity water) implemented on improving the recovery factor of Statfjord I-1 Segment and propose the best method to be applied.

1.4.2 Specific objectives*:*

i. To perform the base case simulation and understand the structure and properties of the reservoir model.

ii. To perform the simulations of the following IOR methods.

- Simulation of surfactant flooding
- Simulation of polymer flooding
- Simulation of low salinity water flooding

iii. To perform economic evaluation for each method and compare their effectiveness based on NPV.

1.5 Scope.

There are many improved oil recovery methods that could be applied for this work. Since IOR is any measures that can be used to improve the oil recovery of the given field thus, there are many methods involved in improving the oil production some of these methods are steam injection, gas injection, carbon dioxide injection, water flooding, chemical injection etc. The scope of this work will focus on simulation work of three IOR methods which are low salinity water flooding, surfactant flooding and polymer flooding.

Apart from simulation work for the three cases this work will also involve the economic analysis of all these IOR methods and conclusion for the best option will be attained. Some IOR methods including infill well drilling, well placement optimization and water flooding process were achieved in semester project may also be compared with these IOR.

1.6 Software to be Used.

Eclipse 100 simulations, ResInsight software and excel will be used to accomplish this work.

CHAPTER 2

2.0 DESCRIPTION AND LOCATION OF THE STATFJORD SEGMENT.

2.1 Gullfaks Field Location and Description.

Gullfaks field is found in northern part of Norwegian sea. The field is situated on block 34/10 of the Norwegian sea. It is owned by StatoilHydro (70%) and Petoro taking the remaining share of 30% however StatoilHydro is the main operator. *(Talukdar & Instefjord, 2008)*. The block was given to Statoil, Nosk Hydro, and Saga Petroleum in June 1978. The first exploration well (34/10-1) was drilled in the same year which encountered a 160m oil column in Brent group and went through the water-bearing Cook and Statfjord reservoirs. The exploration and appraisal phase continued up 1983 with more than 20 wells to evaluate the full field potential *(Tollefsen, et al., 1998)*. Figure 3 describe the location map of the Gullfaks field.

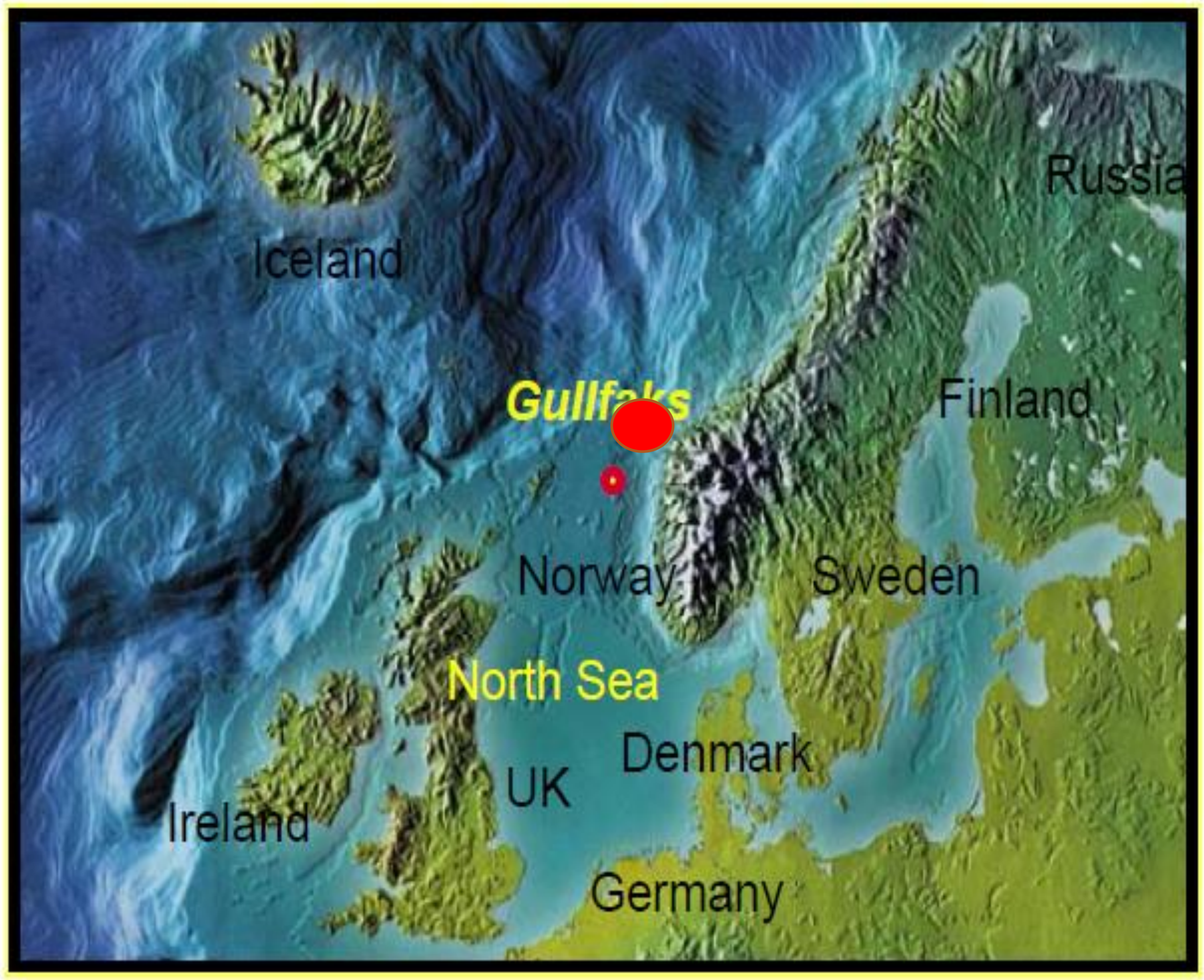


Figure 3:Location map of the Gullfaks field (Talukdar & Instefjord, 2008).

2.2 Discovery and Start of Production.

The Gullfaks field is divided into two main part the Gullfaks main which consists of Statfjord, Cook and Brent formation of Early to middle Jurassic and the Gullfaks satellite which includes Gulltopp, Sor, Rimfaks, Gullveig and Skinnfaks segments. Gullfaks main represent the main reservoir with 78% of total in oil in place of 88% recoverable.

The field was discovered on 1978 and came into production in 1986. (Talukdar & Instefjord, 2008). Some of the recovery factors and number of isolated segments for individual formation are indicated in the table 1 and table 2 below.

Table 1:Recovery factors for individual fields in Gullfaks field.

Formation	Oil Recovery
Brent	60%
Cook-3	28%
Statfjord	56%
Lunde	8%

Table 2: Isolated segments of the Gullfaks formations

Formations	Isolated Segments	umber of Segments
Brent	I1 U1 12A H1 H2 G2 G3 G7 F4 E2 E3	11
Cook	I1 K1 H3 H4 H5 G1 G2 G3 G4 G5 G6 G7 F4 F7 E1 E2 E3 D1 D2 D3 D4	21
Statfjord	K1 K2 K3 J3 13A I1 H1 H2 H3 G1 G2 F7 F4 F3 F2 F1 E1 E2 D1 D2	20
Lunde	H3 H7 I1 K1 J1 J2 L1 L2	8

2.3 Geological Structure of Gullfaks Field.

Gullfaks is found to the west part of the Viking Graben defined by a high point structure along the Tampen area. It contains a lot of rotated fault blocks, made up mainly of pre-but also syn-rift sediments which are young as late Jurassic to early Cretaceous in age separated into three key structural domain named domino zone, accommodation zone and Horst complex as indicated in figure 4. Gullfaks composed of domino system in the central and western part with dipping rotated fault blocks in the west. To the further east there is a non-rotated horst complex.

A complex accommodation zone categorised with fragmented antiformal fold structure lies between the two zones. The complex structure of the Gullfaks is mostly resulted from late Jurassic-early Cretaceous rifting, influenced by earlier rift structures of Permian-Triassic age. Gullfaks is dissected by a set of main faults that form an anastomosing pattern, with a dominant north-south orientation. The offsets of the faults lie within 50-250 meters. (StatoilHydro, 2007).

2.3.1 Domino System.

Here very important reservoirs of Brent Group are maintained in which the main faults indicate an increasing complexity in the direction of more shallow depths. Specifically, a lot of overlapping faults may be detected in vertical and horizontal segments. Relay structures help mostly in fluid flow from one section of the fault to another.

Layer orientation and offset geometry distribution resulted from local changes characterise the relay structures. Some east-west trending faults having offsets below 50m dissect the domino blocks and are considered to be connected to internal block deformation at variance slip along the main faults. The dip of the layers mostly decreases towards the west resulted from large-scale drag of layers into the fault plane. (StatoilHydro, 2007).

2.3.2 Accommodation Zone.

This zone describes a large-scale graben structure categorised by a fragmented antiformal folding structure between domino and host complex. As a result of local extension, the folding part is cut by horst and graben structures. Generally, accommodation zone has the most complex deformed regions on Gullfaks field due to the deformation regimes in both west and east. (StatoilHydro, 2007).

3.3.3 Horst Complex.

The deepest eroded part of Gullfaks filed is found in this zone, in which deposits older than those found in Brent formation are well-maintained. This zone composed of non-rotated fault blocks, when compared to the above two zones, it experiences less internal block deformation effect. However, there may be wide fracturing in some of the areas resulted from its position in relation to the main fault. (StatoilHydro, 2007). There is uncertain structural interpretation as a result of relatively lack of sufficient seismic reflection in the field. This part is characterised by relatively steep (60-65^0) normal faults (figure 4). The consequence of poor continuous seismic reflection at this part fallouts in ambiguous structural interpretation.

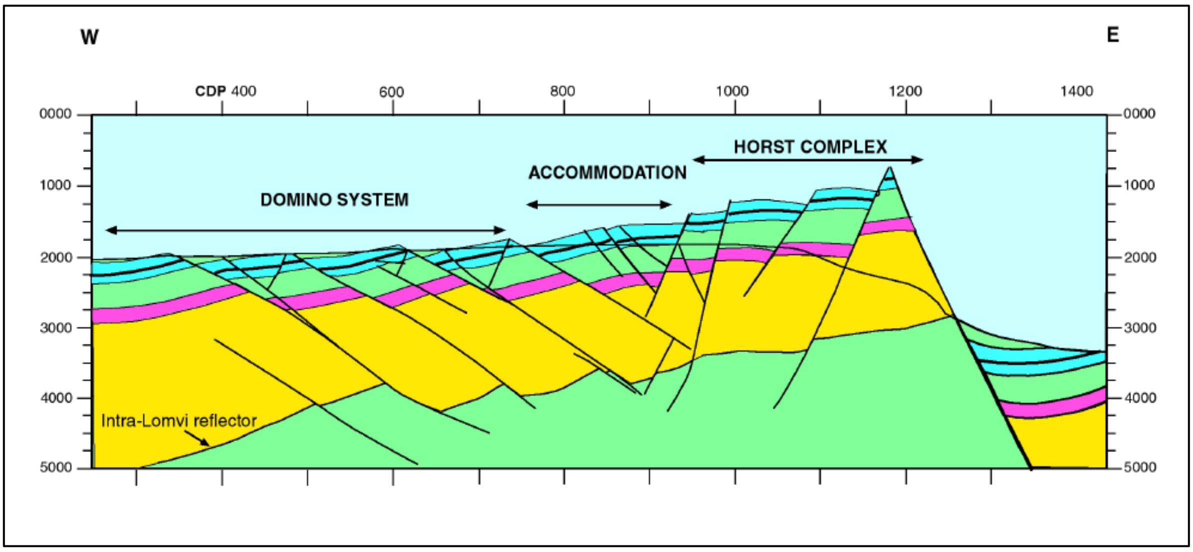


Figure 4: Discerption of faults arrangement in Gullfaks main (Talukdar & Instefjord, 2008)

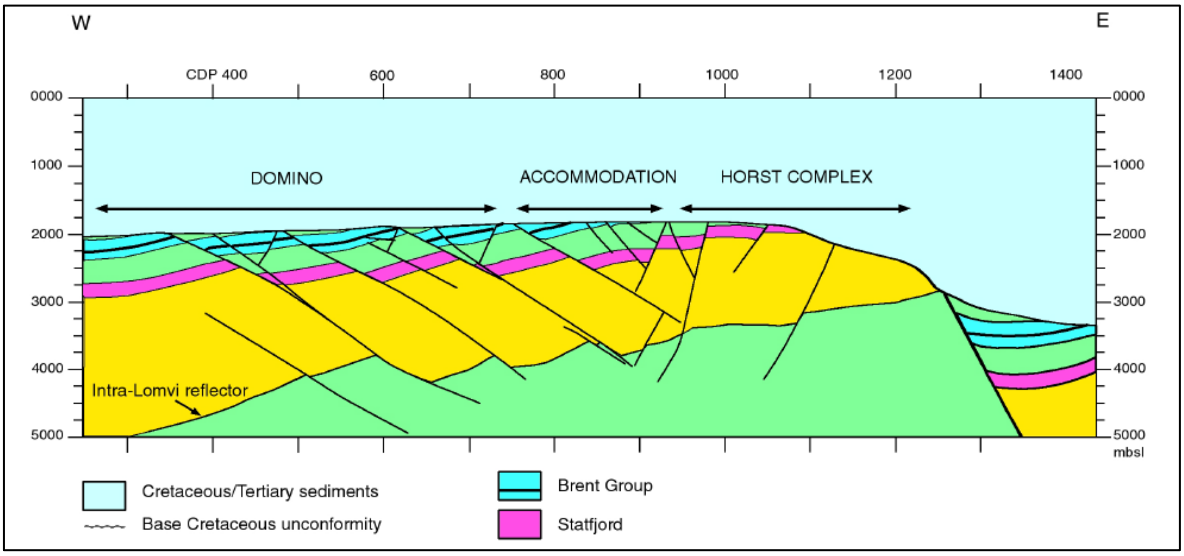


Figure 5: General cross section of the Gullfaks main field (Talukdar & Instefjord, 2008).

2.4 Reservoir Communication in Gullfaks.

The effect of faults in blocks and communication within the reservoir is of great consideration on Gullfaks field. Through collective use of open hole pressure information, structural and stratigraphic information, transient well testing, pressure gauge, well logs data, production data and radioactive tracers the clear understanding of entire communication and fault blocks arrangement in the field can be obtained. (Tollefsen, et al., 1998)

Excellent lateral and vertical communication both internally and amongst faults have been revealed in Tarbert and Lower Brent. Presence of lateral calcite layers can restrict flow though there is good communication in the place.

Apart from that it is difficult to predict flow patterns in heterogeneous reservoirs such as Statfjord formation as well as Ness due to widespread faulting. In general, there is good communication in each fault specified by well performance and pressure data. However, faults having a vertical component of 30-100m eradicate the communication. Seismic interpretation is used to distinguish main faults, even though 70% of the Gullfaks wells, small faults that could not be observed on seismic are identified, resulting in more communication patterns complications. (Tollefsen, et al., 1998).

2.5 Statfjord Formation.

Statfjord is a layered reservoir having some main pressure barriers, in vertical and along the fault blocks. The formation composes of six production zones with changing communications. In some cases, the fault can provide a seal while in some areas communication paths have been observed.

There is a varying level of communication from Lunde formation, Krans and Sverdrup members with Statfjord formation. Statfjord segment I-1 is a separate area of production with the rest and K1 segment detected to be separate from the other K segments (StatoilHydro, 2007)

2.6 Reservoir Description of Statfjord Formation.

Statfjord formation was deposited during the early Jurassic or late Triassic time, as a result of gradual change in the depositional environment from an alluvial environment with intermittent flood deposits in lower parts, to a poor drained alluvial plain having swamps and river channel in the upper parts.

Through some cores, tidal structures have been detected in the direction of the top, suggesting that some meters at the uppermost were deposited in estuarine channels caused by transgression in the zone. The flooding of the entire area resulted into the marine shales deposition in the Amundsen formation as seen in figure 6.

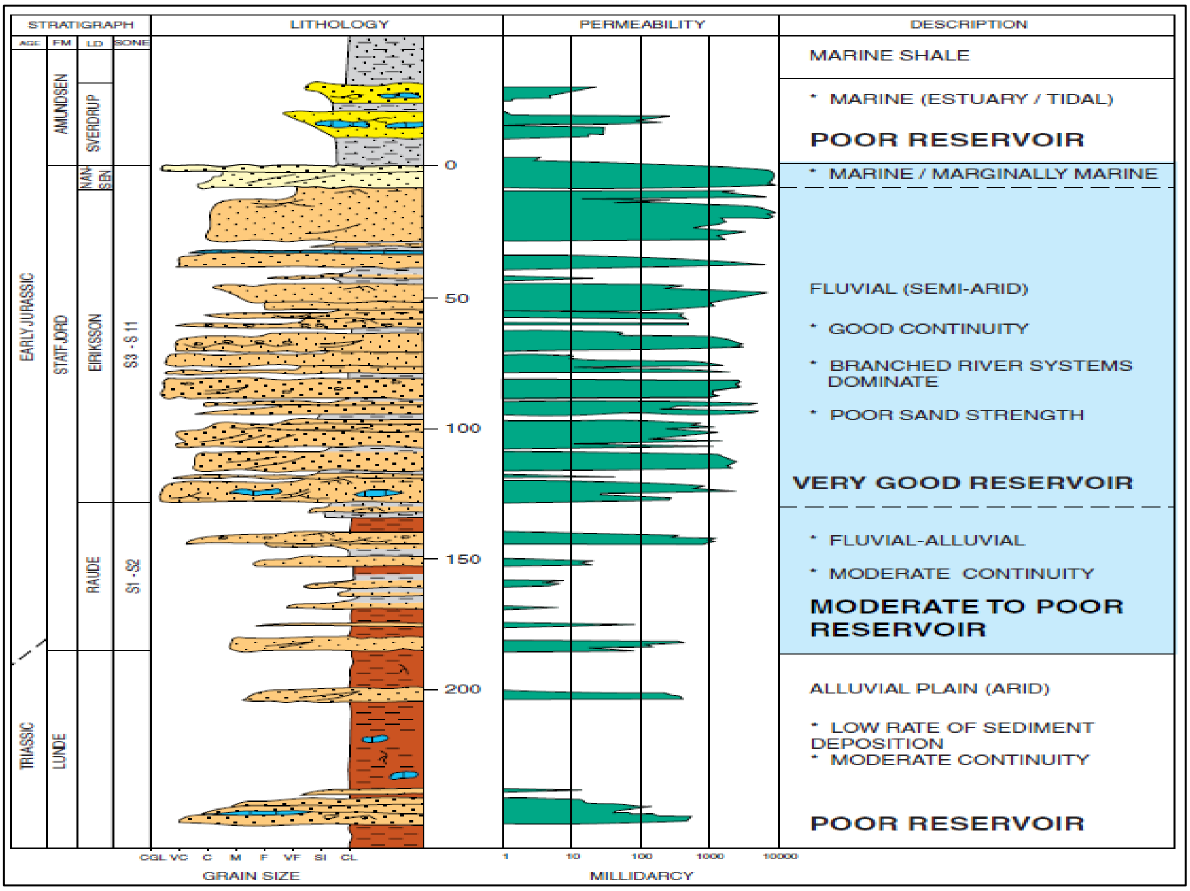


Figure 6: Stratigraphic column, Statfjord Formation, and Sverdrup Member ((Talukdar & Instefjord, 2008).

Statfjord is defined by lithographic criteria with lower mica content compare to the lower part of the formation. The formation is a younger sand with more promising reservoir properties. S1-S2 segment in the lower part of the Statfjord varies in reservoir thickness and quality and categorised by regular alternating sand and shale. (Toft, et al., 2012)

Water injection has been used to maintain reservoir pressure and increase the sweep efficiency to the Statfjord formation. Gas injection has also been used is some segments to drain attic oil. To control the flow of the fluids from the reservoirs with various productivity index and to shut-off water producing zone easily, downhole instrumentation and control system (DIACS) completion has been used. (Toft, et al., 2012).

Some challenges in Statfjord are to maintain reservoir pressure, presence of faults which create seals in some zones and communication paths for some parts. On other sides there is sufficient pressure support while in some areas there is no enough pressure support. The reservoir pressure assessment has been done by injected tracers with water. (Tollefsen, et al., 1998).

2.7 Statfjord Segment I-1.

In Statfjord formation it has been detected that there is no communication between I-1 segment and other I segment. Water has been injected in the southern part of I-1 segment to drive the oil towards the producers located far in the northern part of the segment. Up to 2001 there was 3 wells drilled two of which are producers (A-36, A-40 & B-39B) and one injector A-41 (StatoilHydro, 2007).

Injector A-41 located to the southwest within I-1 segment provide less pressure support for the two producers, this was resulted from the presence of deformation bands linked with the main fault between H-1 and I-1 segments. New injector A-41B was drilled in northeast of the segment outside of the deformation band region in October 2001, resulting in good pressure support to the producer wells in I-1 (Talukdar & Instefjord, 2008).

Gas injection was achieved using well A-41B which was a water alternating gas (WAG) in 2004 only as a first and last, resulted in increase in GOR in Statfjord I-1 with huge temporary raise in water cut for well B-39B. As a result of gas injection well A-40, was sanded up to give the cleaning effect in the well with high oil production rate. Furthermore, there was a gas injection plan per month every year. Well B-39B was drilled in order to speed the oil production from Statfjord I-1 segment in 2003 in the northern part of I-1 segment.

To attain a production target in Cook from I-1 segment, there was a plan to sidetrack well A-36 in the beginning of 2008 which prevented back production in lower Brent. A-40 was considered to be a water-free producer between early 1998 up to January 2005 where the water cut started to increase up to about 85% in 2006 with oil production rate of 230Sm^3/d.

Due to the rise in water cut the well was plugged above lower Brent and perforated in Cook segment H-2. However, the plan to pull the plug above Brent formation and fracturation of Cook to obtain commingle production from the two formations failed as a result of access problems in lower Brent, thus production is only coming from Cook formation while Brent formation is still plugged.

Based on the geological structure of the formation, well B-7A was drilled and penetrate only the upper parts of lower Brent stratigraphy. The well was completed with min- fracture using proppants in three intervals to avoid sand production. The well was drilled in December 2002 and start production in April 2004, but it died in early 2005 because of low pressure (StatoilHydro, 2007).

A side tract well B-7B drilled between October and November 2006, was found to be dry resulted to another sidetrack (B-7C) in December 2007 to Cook formation which then was used as an injector. Figure 7 describes the location map of Statfjord I-1 segment.

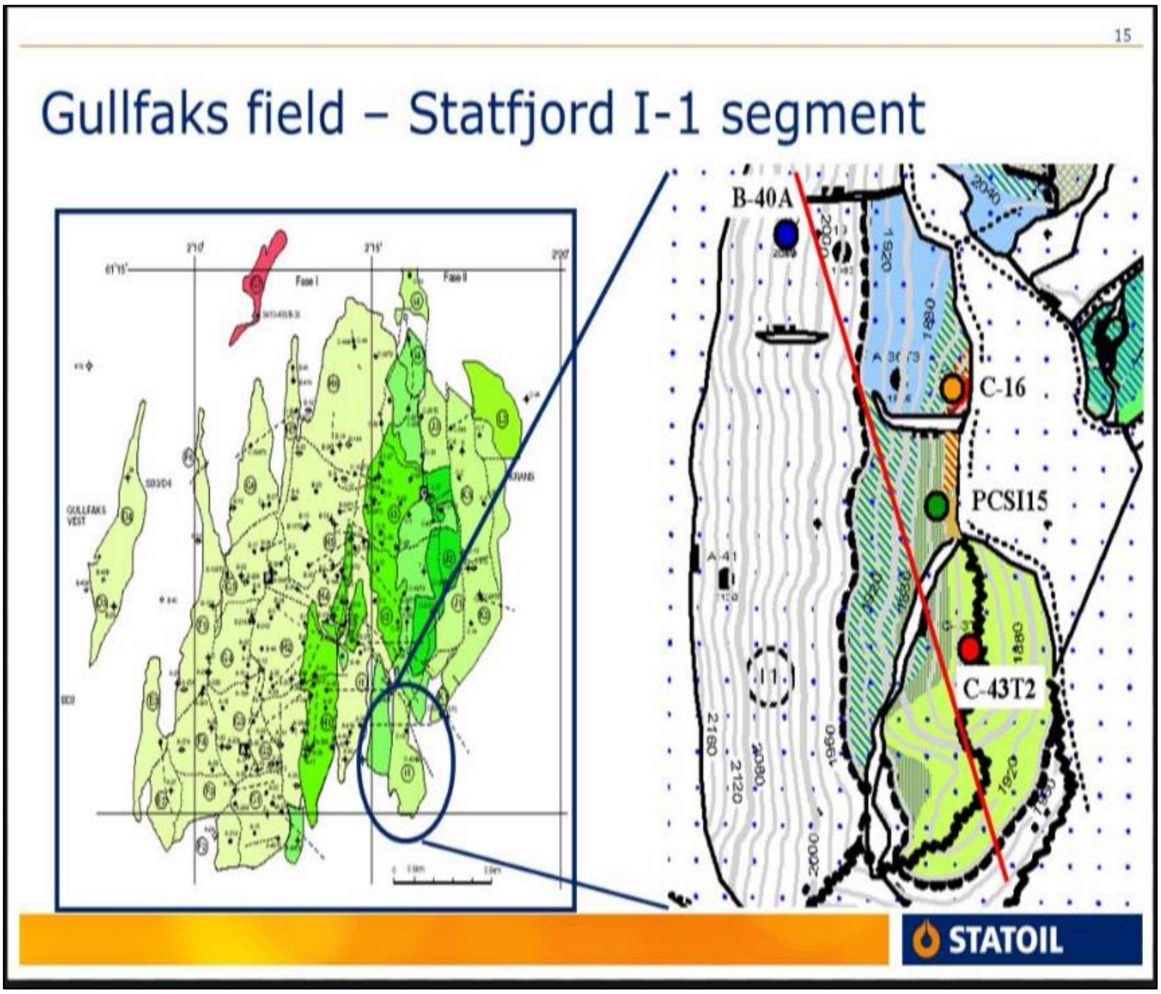


Figure 7: Location map of Statfjord I1 segment(Statoil,2010)

CHAPTER 3

3.0 LITERATURE REVIEW

In this part various improved oil recovery (IOR) methods have been reviewed to get familiar with the real situation when it comes to simulation works based on these methods. Some of the IOR methods which have been reviewed include well placement optimization, water flooding, polymer flooding, surfactant flooding and low salinity water flooding. It is important to know the basic theory of these IOR methods before putting them in really practice. Through literature review it can be easy to understand how these methods can be applied during simulation works.

3.1 Well Placement Optimization.

During the initial stage of development plan, the optimal well location is the great challenge facing the oil and gas industry. As a result, wrong decisions can result to wastage of money, recovery, and field equipment (Ermolaev & Kuvichko, 2013). As the reservoir performance is greatly depending on the location of the well, the analysis of well placement optimization should be given special consideration at planning stage (Badru & Kabir, 2003). Since engineering and geology variables affecting the performance of the reservoir are frequently nonlinearly correlated, intuitive judgment cannot be used to achieve optimal well location (Ermolaev & Kuvichko, 2013).

Direct method using reservoir simulators is one way that can be used to solve the optimal well location challenge using numerical models which are capable of analysing complex variables like reservoir and fluid properties, well and surface networks as well as economic factors (Badru & Kabir, 2003).

In major field the well placement should consider various challenges such as well collisions and high well density which may result in difficult when designing well paths. It is indicated that low risk of well collision is to achieve the Oriented Separation Factor (OSF) of 1.5, though it is difficult to attain separation factor greater than one (Okafor & Moore, 2009).

“Oriented Separation Factor is defined as the center to center separation between wells and the ellipsoid of uncertainty separation”. Proper well placement will result in improved oil recovery as a result high NPV will be obtained.

3.2 Water Flooding

Waterflooding is one of the improved oil recovery method (secondary recovery) achieved by injecting water into the reservoir to add or maintain the reservoir energy which result to increase the oil production. It can be applied at the start of production to maintain the reservoir pressure or when the natural drive is insufficiency to push the oil to the wellbore. Water flooding has proven to be the most successful and most widely used improved oil recovery method due to the facts that water is available easily with low cost compared to other injection fluids, injection of water in the formation is simple with high oil displacement efficiency (Cobb & Smith, 1997).

3.2.1 Waterflooding against Pressure Maintenance.

Water injection is considered as pressure maintenance when it starts at the begging of production or when the reservoir pressure is still high enough to produce the reservoir oil, but when the reservoir pressure resulted from natural drive is very low to produce the oil from the reservoir the injection water is termed as waterflooding.

The oil displacement processes under all circumstances is dynamic. However, oil displacement at high pressure (pressure maintenance) in difference from the one occurs at low reservoir pressure. The important differences between the two processes are

According to (Ahmed, 2006), Thomas, Mahoney, and Winter (1989) mentioned that to apply waterflooding the suitability of a candidate reservoir can be determined by considering the reservoir properties below.

3.2.2 Reservoir Geometry.

The wells location is influenced by the areal geometry of the reservoir and in case of offshore fields this influence both the location and the number of platform needed. The means in which the reservoir should be produced by injecting water is also determined by the reservoir geometry.

It is necessary to study the previous reservoir performance and geometry to understand the available and strength of the natural water drive before deciding for the waterflooding. In case it happens that there is an active water drive, the need for injection may not be applicable (Ahmed, 2006).

3.2.3 Fluid Properties.

The suitability and efficiency of the given reservoir for waterflooding is determined by the physical properties of the reservoir fluids at large. Viscosity as one of the fluid properties should be given a great consideration for successfully waterflooding since it is an important factor to affect the mobility ratio and controls the area sweep efficiency (Ahmed, 2006).

For a single-phase fluid, the mobility ratio is defined as the ratio of permeability to viscosity of fluid represented by equation 1, and for multiple phase fluids flowing in a reservoir the mobility ratio is given by using equation 2 (Lyons & & Plisga, 2005).

$$\lambda = \frac{k}{\mu} \qquad 1$$

$$M = \frac{Krw\mu o}{\mu wKro} \qquad 2$$

Generally, for waterflooding mobility ratio is represented by the ratio of mobility of water to that of oil as represented by equation 2. For stable condition mobility ratio (M) should be less than one.

3.2.4 Fluid Saturations.

When planning for waterflooding the oil saturation is very important factor to be considered as it gives the indication of enough amount of oil to be recovered from the reservoir. Presence of high oil saturation at the beginning of waterflooding process determines the recovery efficiency because of increased oil mobility (Ahmed, 2006).

3.2.5 Lithology and Rock Properties.

Clay content, porosity, permeability, and Net thickness are the reservoir characteristics which determine the efficiency and success of waterflooding. The reservoir permeability and the net thickness affect the rate of water injection and the injection pressure, mathematically this can be analysed using equation 3 (Ahmed, 2006).

$$P_{inj} = \frac{Qw}{hk} \qquad 3$$

Where

P_{inj} is the injection pressure

Qw is the rate of water injection and

h is the net thickness and k is the reservoir permeability.

3.2.6 Reservoir Depth.

It is necessary to consider the depth of the reservoir economically and technically before introducing waterflooding project, since the pressure increases with depth. To produce oil from a very deep well results in increasing of the total operating cost of the project with less ultimate recovery factor since it limits the maximum economic water-oil (W/O) ratios tolerance that can be achieved.

In other side, shallow reservoir enforces a limitation to the injection pressure to be used, since it should be less than fracture pressure. For water flooding a pressure gradient of 0.75psi/ft of depth is allowed for safety to avoid pressure parting during waterflooding (Ahmed, 2006).

3.2.7 Reservoir Uniformity and Pay Continuity.

One of main physical criterion for safe and successful waterflooding is considerable reservoir uniformity. The non-uniformity can result to some problems such as high channelling and bypassing. Continuity of the pay zone one of the necessary factor for better waterflooding process, since the flood mechanism needs the injector and the producer to be in connection. Presence of faults or fractures and reservoir anisotropy because of depositional conditions should be recognized and analysed before planning for well placement and flood pattern alignment (Ahmed, 2006).

3.2.8 Injection well placement for water flooding.

When designing waterflooding project, it is necessary to select the flood pattern first. To achieve maximum contact between the injected fluid and the fluid to be displaced for success waterflooding project proper flooding pattern must be chosen (Ahmed, 2006). This may be achieved through drilling new wells (infill drilling) or by converting some production wells into injectors.

There should be compatibility between the injection and the producer wells which must consider the understanding of the reservoir uniformities or non-uniformities, give enough fluid injection to attain the desired production rate, to obtain maximum oil recovery with few injection wells (Lyons & & Plisga, 2005). According to (Lyons & & Plisga, 2005) there are two general types of well locations which are peripheral or central flooding and pattern flooding.

3.2.8.1 Peripheral or central flooding.

This is the method in which injector wells are gathered together. For peripheral flooding, injection wells are positioned at the edge in which case the flood advancement toward the center where the production wells are located as indicated in figure 8. The first row of producer wells is changed to injectors after flooding out (Lyons & & Plisga, 2005).

In central flooding, injection wells are situated at the centre of the field and the flood progress outwards where producer wells are found as seen in figure 8.

Generally, for successful flooding sufficient permeability is needed to allow the fluids to move with adequate rate to the producers based on available well spacing (Lyons & & Plisga, 2005).

Although peripheral flood takes much time for injected water to fill the reservoir gas space because of few injectors compare to pattern flood, it always gives maximum oil recovery with lower amount of produced water. It also need less amount of injectant which may result in delay of the field to the flood response (Ahmed, 2006).

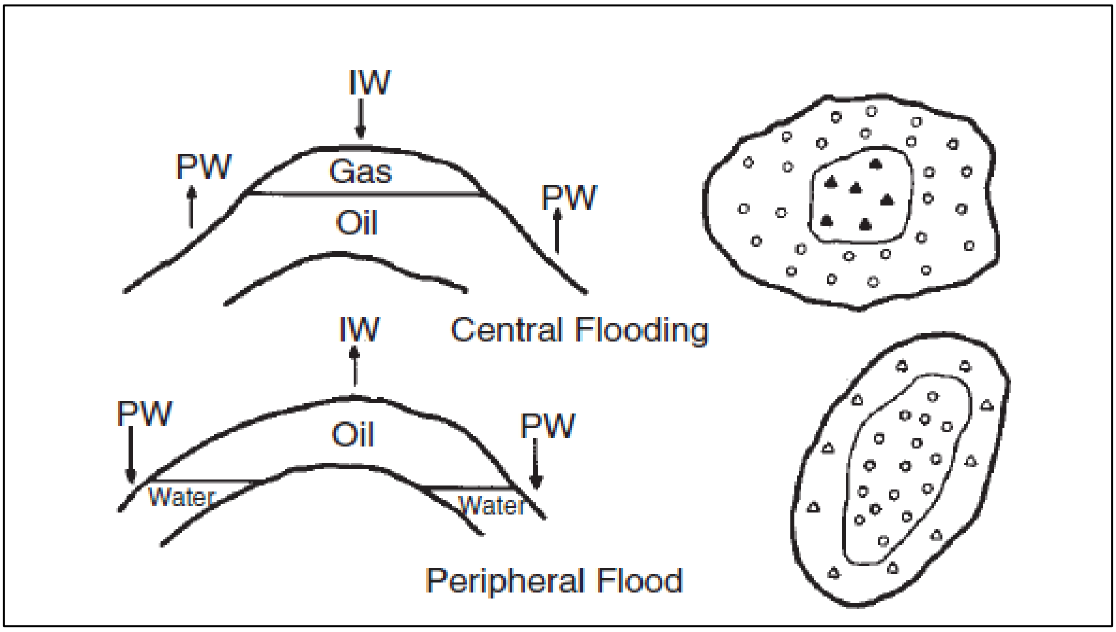


Figure 8:central or peripheral flooding description (Ahmed, 2006)

3.2.8.2 Pattern flooding.

In this type of flooding the injection wells are placed around the production well in a repeatd arrangement as seen in figure 9. The pattern to be used is determined by the conditions within the field. In most cases 5-sports and 9-sports are the most common patterns which yield same oil recovery as well as water oil ratio (Lyons & & Plisga, 2005). Other patterns include 7-sports, direct line drive and staggered line drive.

Generally in case injected fluid moves faster compare to fluid to be displaced, it is preferred to have a pattern with more producers than injectors, and for reservoir with low permeability or when the injected fluid moves slow than the fluid to be displaced the pattern with more injector than producers is preferred (Ahmed, 2006). Formation permeability, reservoir area and dimensions, formation dip and the preliminary production response are the basic consideration for peripheral or pattern flood to be chosen.

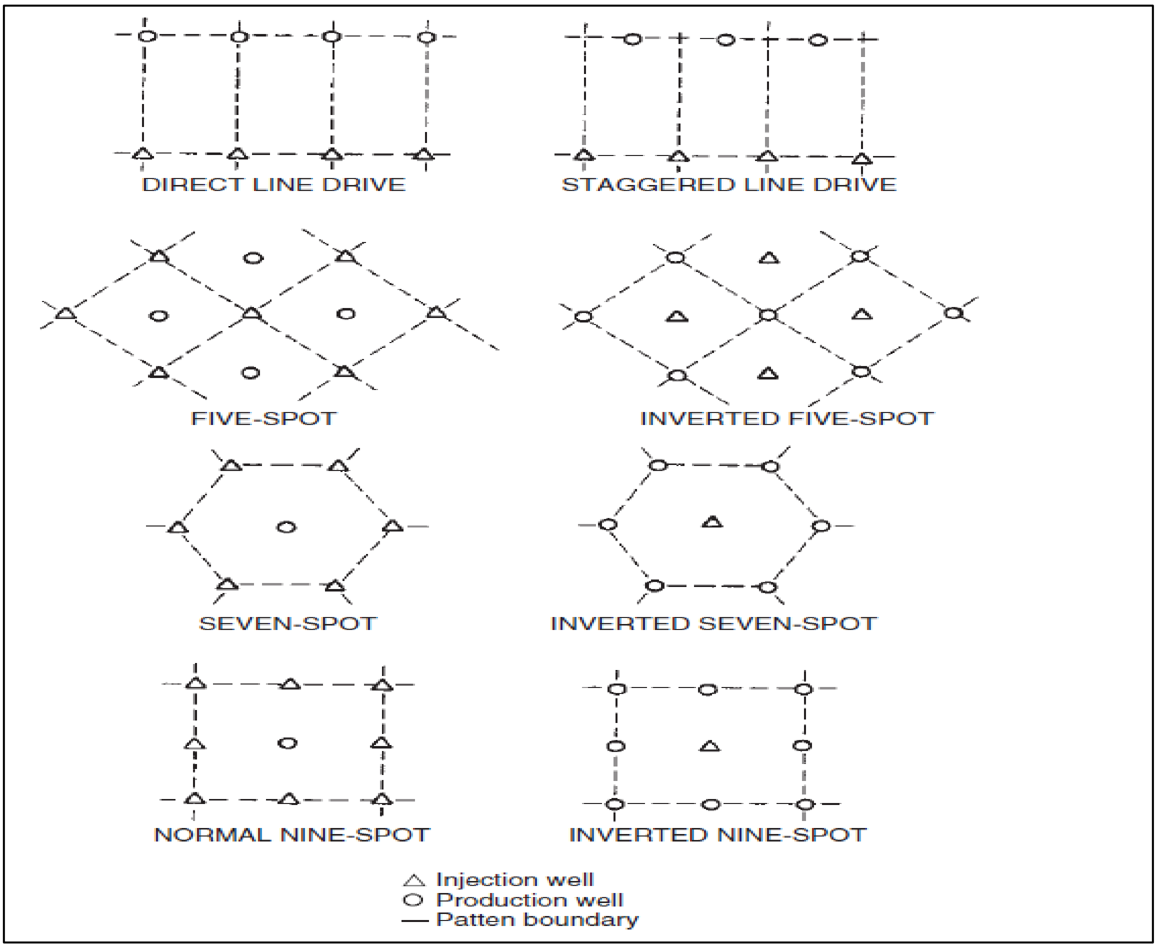


Figure 9:Description of various well location in pattern floods ((Lyons & & Plisga, 2005)

3.2.8.3 Displacement Mechanism of Water flooding.

(Lyons & & Plisga, 2005) Pointed out that piston like displacement is the mechanism in which water displaces oil from the pore space of the reservoir rock for ideally. Even though the way in which water displaces oil and the direction of where the flow of each fluid occurs is determined by the wettability and relative permeabilities of water and oil.

3.2.8.4 Overall Recovery Efficiency of Waterflooding.

The recovery efficiency is defined as the ratio of the oil recoverable economically to the total oil initially in place. Nature of the reservoir rock, fluid viscosities, fluid saturations, oil- water relative permeabilities, capillary pressure, location of injection and production wells, reservoir heterogeneity and pore volume are the factors which control the displacement efficiency of water flooding. (Lyons & & Plisga, 2005). The overall oil recovery efficiency (E_R) is obtained by multiplying three individual efficiency factors as represented by equation 4.

$$RF = E_D \times E_A \times E_V \qquad 4$$

In term of cumulative oil produced by water flooding and initial oil in place the equation 4 can be represented by equation 5 (Cobb & Smith, 1997)

$$N_P = N \times E_D \times E_A \times E_V \qquad 5$$

where RF is the overall recovery factor

E_D = displacement efficiency given as

E_A = areal sweep efficiency

E_V = vertical sweep efficiency

N = oil initially in place

N_P = cummulative oil produced by water flooding.

Displacement Sweep Efficiency (E_D).

Displacement efficiency is one of the factor which affect the overall efficiency and it is determined by the pore volume geometry, wettability, fluid distribution in the reservoir, fluids distribution and the saturation history of the reservoir (Cobb & Smith, 1997).

3.2.8.5 Areal Sweep Efficiency (E_A)

This is the part of the reservoir in which the injected water will contact during the water flooding process (Cobb & Smith, 1997). Type of pattern to be used, the oil and water mobilities, pressure distribution between the injector and the producer, heterogeneity of the area and the amount of injection fluid are the factor which determine the areal sweep efficiency (Ahmed, 2006). Figure 10 shows the areal sweep.

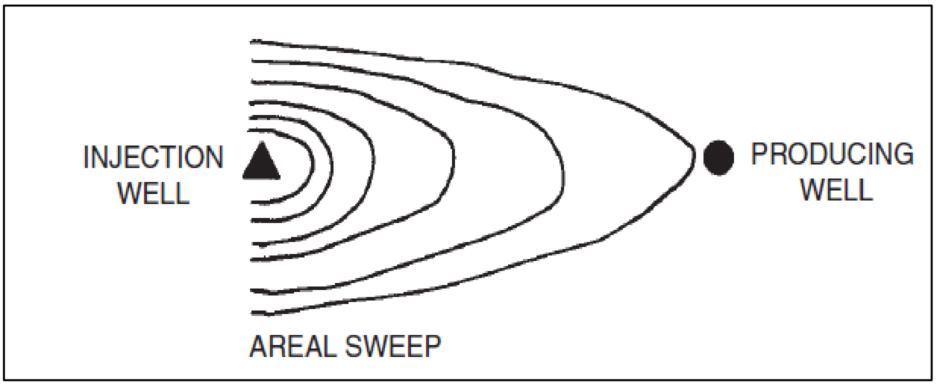


Figure 10: Description of areal sweep ((Lyons & & Plisga, 2005)

2.2.8.6 Vertical Sweep Efficiency (E_V).

This is the fraction of the reservoir which will be contacted in vertical section by injected water. Vertical sweep depends on the vertical heterogeneity, degree of gravity segregation, fluid mobilities and the total injected volume of water (Cobb & Smith, 1997). The effect of vertical sweep efficiency is described in figure 11.

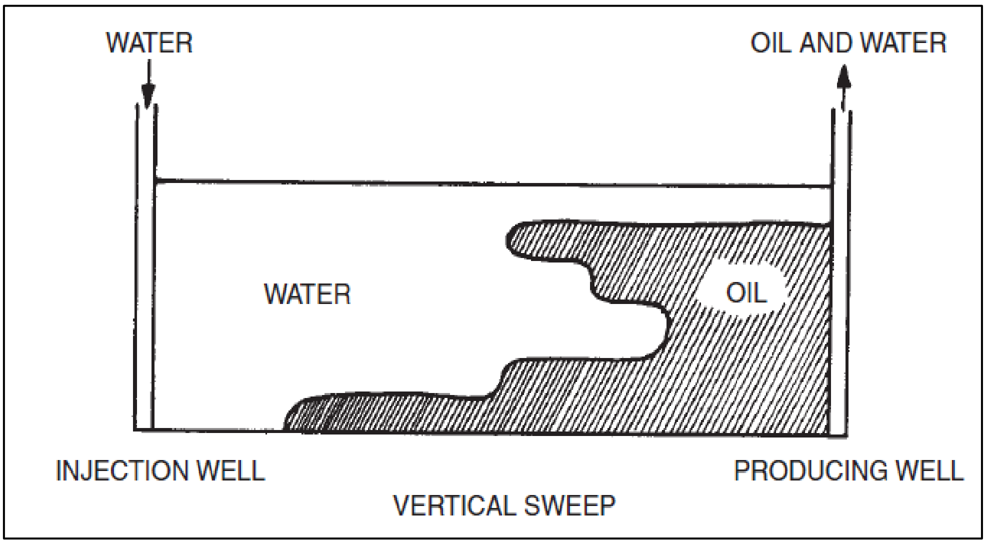


Figure 11: Description of Vertical sweep efficient (Lyons & & Plisga, 2005)

3.3. Polymer Flooding

Polymer flooding as one of the Enhanced Oil Recovery Methods was put in test since 1960’s. Polymer can improve the recovery of oil by affecting the viscosity of flooded water which then reduce the mobility ration as a result improve the volumetric sweep efficiency hence more oil is forced to move through the production well in which more oil is recovered. (Yugal, 2011)

During polymer flooding some amount of polymer is introduced into the injected water to increase the viscosity of the water as a result reduce the mobility of the flooded water thus increasing sweep efficiency. The reduction in mobility ratio is resulted by the increase in viscosity and lowering of aqueous phase permeability resulted by polymer added to the flooding water. (Teknica, 2001)

By lowering mobility ratio, the efficiency of injected water is increased which result in great volumetric sweep efficiency as well as lowering of oil saturation swept zone. Increase in recovery efficiency creates the economic motivation to apply polymer flooding technique.

High mobility ratio, high reservoir heterogeneity or combination of the two identify the economics of the polymer. By thickening the injected water volumetric coverage, mobility ratio can be improved, which then result in high oil recovery.

(Lake, 1989) Some literatures indicate that commercially polymer flooding was achieved in China in which field oil efficiency was improved up to 20% when polymer flooding technique was used. Recently polymer flooding can be identified as one of the successful and lucrative improved oil recovery methods. (Huseynli, 2013)

3.3.1 Types of Polymer.

There are quite a lot of polymers to be considered when applying polymer flooding including xanthan gum, hydrolysed polyacrylamide (HPAM), copolymers (a polymer consisting of two or more different types of monomers) of acrylic acid and acrylamide, copolymers of acrylamide and 2-acrylamide 2-methyl propane sulfonate(AM/AMPS), polyacrylamide (PAM) polyacrylic acid glucan, dextran polyethylene oxide (PEO) and polyvinyl alcohol. (Lake, 1989)

Even though all the polymers are grouped into two generic classes, which are hydrolysed polyacrylamide (HPAM) and biopolymers (polysaccharides) such as xanthan gum. Natural polymers and their derivatives like guar gum, sodium carboxymethyl cellulose and hydroxyl ethyl cellulose (HEC) are not commonly used polymers in IOR. (Lake, 1989)

Generrally there two types of polymers which have been commonly used in polymer flooding, these are synthetic polymers which are polyacrylamides and biopolymers which are polysaccharides. (Lake, 1989)

During flooding process the performance of synthetic (polyacrylamides) depends on its degree of hydrolysis and its moleculer weight. Part of the acrylamide is changed into or replaced by acrylic acid when polyacrymide is partialy hydrolized resulting in increase in viscosity for fresh water on another side decrease in viscosity in hard water. (Needham & Doe, 1987)

When all other factors are maintained, for same concentration, a high molecular weight polymer will yield higher viscosity and resistance factors compare to a lower molecular weight polymer. Although these are advantages but can be a problem for the shear degradation which reduces molecular weight, leading to low permeability formations by reduced injectivity. (Needham & Doe, 1987)

3.3.1.1 Synthetic (Polyacrylamide).

Polyacrylamide is used mostly in polymer flooding process since it has significant ability to increase the viscosity than xanthan solutions. It has strong ability to be adsorbed on the rock surfaces, thus partially hydrolysed to decrease adsorption when reacting with a base. After hydrolysis some of the amide groups are converted to carboxyl groups (coo-) as seen in figure 12

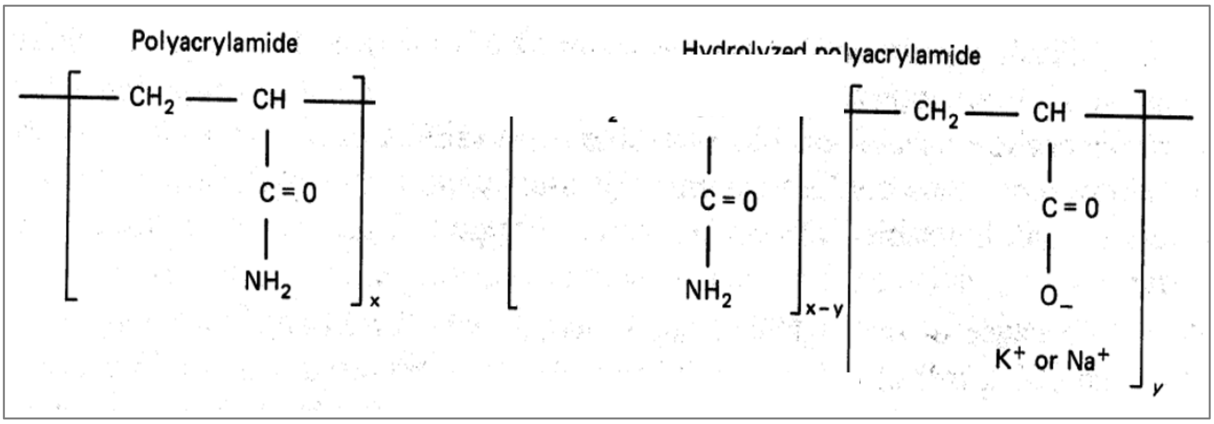


Figure 12:Description of synthetic (polyacrylamide) polymer (Lake, 1989)

Polyacrylamide are polymers whose monomeric part is the acrylamide molecule. During polymer injection polyacrylamide is partially hydrolysed causing anionic carboxylic groups (-coo-) distributed laterally to the main chain. This tendency made these polymers to be identified as partially hydrolysed polyacrylamides (HPAM).

The negative charge of the HPAM accounts for most of the physical properties it possesses. Some properties such as viscosity, water solubility, and retention are optimized based on the level of hydrolyses selected. Very small hydrolyses will result into not soluble water while too large hydrolyses can lead to very sensitive polymer to salinity and hardness. The characteristic of the HPAM to increase viscosity is resulted by its heavy molecular weight. (Lake, 1989)

3.3.1.2 Polysaccharides.

Polysaccharides are types of polymers obtained from polymerization of saccharide molecules by fermentation process of bacteria. Before polymer flooding there are considerable debris left in the polymer products during fermentation process which must be removed. This polymer can also be affected by bacterial after it has been injected into the reservoir. These bring problems of insensitivity of the polymer properties to the hardness and salinity of the brine.

Polysaccharide molecule is relatively nonionic thus it is not affected by ionic shielding of HPAM. As they are more branched than HPAM, oxygen-ringed carbon bond is not rotating in fully, resulting in molecule addition of viscosity snagging with increasing more rigid solution. Polysaccharide has no permeability reduction tendency. (Lake, 1989)

Even though HPAM is inexpensive compare to polysaccharide though when compared on unit amount on mobility reduction specifically in high salinities the costs are almost the same.

From literature it has been reported that about 95% of the field polymer flooding has been using HPAM. At high temperature all polymers are chemically degraded. (Lake, 1989)

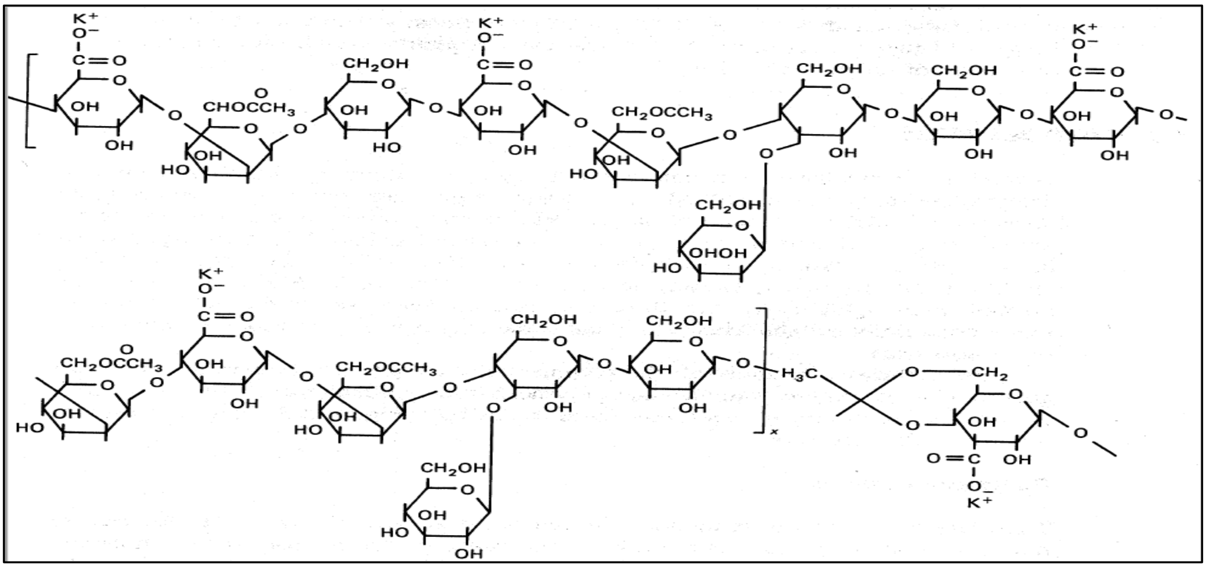


Figure 13: Description of Polysaccharides as an example of polymer (Lake, 1989)

3.3.2 Advantages and Disadvantages of Polymers:

Both synthetic polymers and biopolymers have advantages and disadvantages. Polyacrylamide are cheaper, can provide good viscosity in fresh water and has good ability to be adsorbed on rock surface resulting on long-lasting permeability reduction.

Shear degradation tendency at high flow rates and poor performance in high-salinity water are the most common disadvantages of polyacrylamide polymers. Outstanding viscosifying ability when used in high salinity water and the power to resist shear degradation are the primary advantages of the biopolymers.

When compared to polyacrylamide, biopolymers propagate very eagerly into the formation since they are not reserved on rock surface. This can be considered as an offset advantage since it reduce the needed flooding amount resulting into non-residual resistance effect.

In general, all polymers are restricted for a given range of reservoir conditions in which they can work effective. In temperature above 200^0F (93^0C) biopolymers are thermally degraded very quickly, while at a temperature above 170^oF (77^0C) polyacrylamides can precipitate in water with high calcium. All these bring about difficult to control the salinity of injecting water (Needham & Doe, 1987).

3.3.3 Mechanisms of Polymer Flooding.

Most common and clear mechanism of polymer flooding is to increase sweep efficiency by reducing viscous fingering**.** This is important when improving the water-injection profile due to cross flow between vertical, heterogeneous layers. More effective water flooding resulted by reduced permeability after polymer flooding. Decreasing relative permeability of water flow (k_{rw}) more than the permeability of oil flow (k_{ro}) through disproportionate permeability reduction.

During polymer flooding, water soluble polymer is introduced to the injected water to increase the viscosity of the water. In the swept zones he effective permeability to water can be reduced subjected to type of the polymer used. (Teknica, 2001)

Polymer flooding can improve the oil recovery process more efficiently in three possible ways which are, fractional flow effect of polymers, by decreasing water or oil mobility ratio and by diverting flooded water from zones which already been swept.

Reservoir temperature and chemical properties of water are the critical conditions to be considered for polymer flooding. When reservoir water contains high salinity at high temperature, polymer cannot maintain its stability as a result it will lose its viscosity (Lake, 1989).

3.3.4 Principle of polymer flooding.

Typically, polymer flooding process involves mixing and injecting of polymer mostly hydrogel polymer within an extended duration of time until around one-third (1/3) to half (1/2) of the reservoir pore volumes have been flooded. The injected polymer slug is then followed by water injection to drive the polymer slug and the oil contained ahead of it to the production wells see figure 15.

To attain the required pore volume, polymer injection is maintained for some period of years. The flooded water finds the less resistance ways (mostly high permeability layers) to the lower pressure area of the counterbalance producing wells. For reservoir oil with higher viscosity than flooded water, there will occur water fingering in the oil resulting in poor sweep efficiency. The preliminary analysis of the reservoir is achieved by considering the mobility ratio which indicates the effect of viscosity and relative permeability of water and oil of fraction flow (Abidin, et al., 2012). The lower the mobility ration (i.e M<1) the best the sweep efficiency. The effect of mobility control can be resulting into viscous fingering can be described by figure 14.

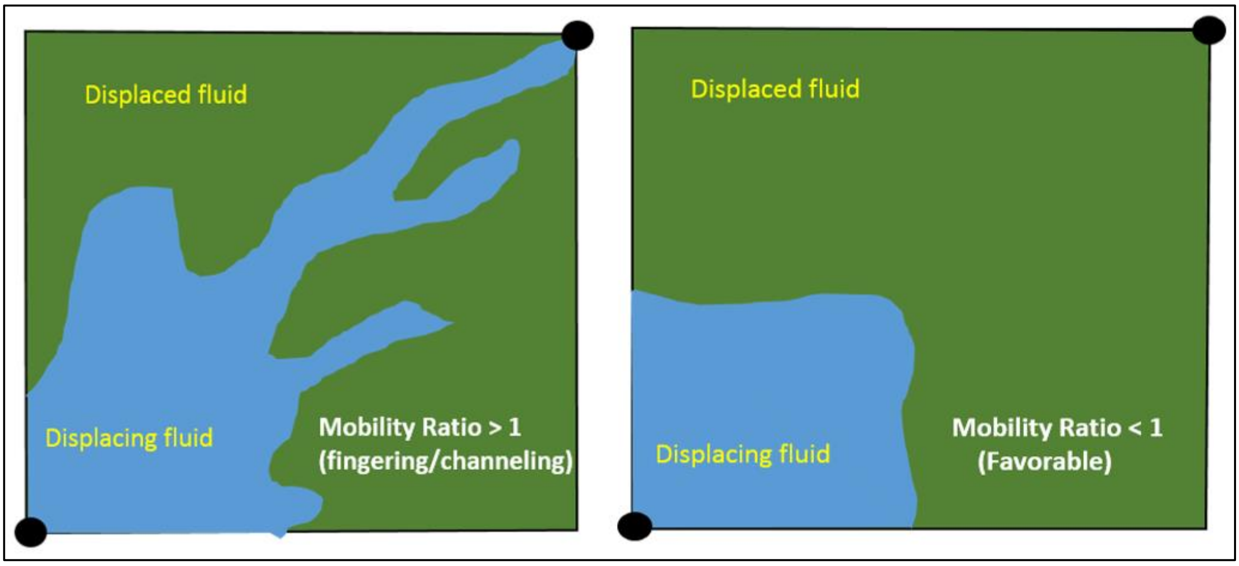


Figure 14: The effect of polymer in reducing viscous fingering (PDO, 2013)

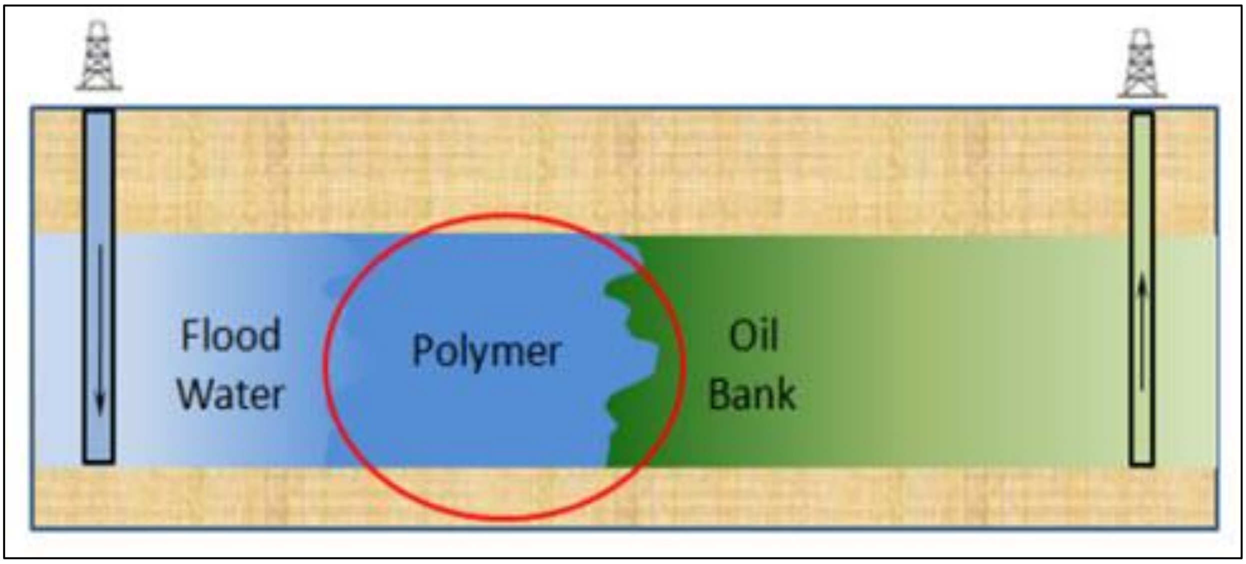


Figure 15: Flow behaviour of polymer in the system (PDO, 2013)

3.3.5. Flow Characteristics of Polymer in The Reservoir.

3.3.5.1 Polymer Retention.

Retention of polymer describes all the mechanisms responsible for the reduction of mean velocity of the polymer molecules when they move through permeable reservoir. Retention of polymer molecules at the reservoir rock can be resulted by adsorption on the surface of the pores, mechanical entrapping in pores and precipitation.

The interaction between polymer molecules and solid surface is termed as adsorption, which causes polymer molecules to be bound to the surface of the rock. During polymer flow in the reservoir precipitation and mechanical entrapping occur see figure 16. (Lake, 1989)

Polymer retention in a reservoir rock occur because of adsorption on solid surface, mechanical trapping inside pores and precipitation. Type of polymer, polymer molecule weight, rock composition, salinity and hardness of the brine, flow rate and temperature are the factor affecting polymer retention. Loss of polymer from solution which then can result into loss of mobility control, a delay in rate of polymer concentration and generated oil bank propagation are the effects retention. (Yugal, 2011).

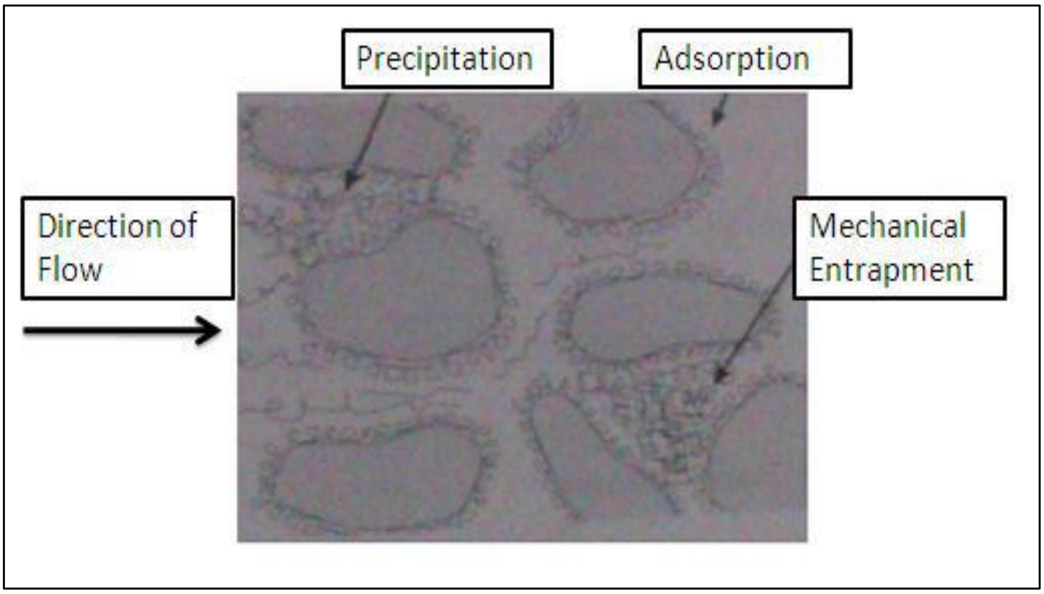


Figure 16: Polymer precipitation, adsorption and entrapment in the reservoir (Yugal, 2011)

3.3.5.2 Inaccessible Pore Volume.

If the sizes of some pores in the reservoir are smaller than the sizes of the polymer molecules, the polymer molecules cannot flow through those pores. The non-accessible volume of the pores by the polymer molecules is called inaccessible pore volume (IPV).

For aqueous polymer solution containing tracer, polymer molecules will propagate quicker than tracer as they flow only in large pore compare to their sizes as a result early polymer breakthrough in the runoff end. Consequently, due to polymer retention, polymer breakthrough is delayed. (Sheng, 2011)

Some of the factors in which inaccessible pore volume depends on are polymer molecular weight, salinity, porosity, reservoir permeability and pore size distribution. In most cases inaccessible pore volume is about 30% of the total pore volume. (Lake, 1989).

3.3.5.3 Permeability Reduction:

During polymer flooding, adsorption of polymer through the reservoir rock can result in pore blocking or reduction in permeability. Thus, the reduction in permeability is high when polymer solution is flowing compare the permeability resulted by water flooding. Permeability reduction is expressed by Fkr, the permeability reduction factor is represented by equation 6 (Sheng, 2011).

$$Fkr = \frac{Rock\ permeability\ when\ water\ flows}{Rock\ permeability\ when\ aqueous\ polymer\ solution\ flows} = \frac{kw}{kp} \qquad 6$$

Type of polymer, amount of polymer retained, distribution of pore sizes and the average polymer size of the polymer relative to the pores in the rock are the factors in which permeability reduction depends on (Green & Willhite, 1998). Other two parameters which are used to study the flow behaviours of polymer in the reservoir are resistance factor and the residual resistance factor.

The ratio of water mobility to polymer solution mobility flowing under the same conditios is defined as the resistance factor R_f and it is expressed by equation 7.

$$Rf = \frac{\lambda w}{\lambda p} = \left(\frac{kw}{\mu w}\right) \Big/ \left(\frac{kp}{\mu p}\right) \qquad 7$$

The ratio of the mobility of water before contact with polymer solution to the water mobility when all the mobile polymer has been displaced from the pores is defined as the Residual resistance factor (R_{rf}) (Sarkar, 2012). Mathematically it is expressed as shown in equation 8.

$$R_{rf} = \frac{kw}{kwp} \qquad 8$$

3.3.5.4 Rheology of Polymer in Porous Media.

To understand the rheological properties of the fluid, viscosity is one of the important parameter to be considered. The fluid can behave as Newtonian or non-Newtonian based on the rheological properties. Water is a Newtonian fluid in which the flow rate varies linearly with pressure gradient (ie the viscosity of water remains constant), so viscosity is independent of flow rate. Polymers in aqueous solution show non- Newtonian fluids rheological behavior.

The general rheological behavior is expressed as the function of apparent viscosity, shear stress and shear rate as seen in the equation 9.

$$\tau = \gamma\mu$$

$$\mu = \tau/\gamma \qquad 9$$

In polymer flooding the apparent viscosity of the polymer solution decreases with increase in shear rate. The fluids which exhibit this tendency is said to be shear thinning in which case this effect is known as pseudo plastic. Biopolymers such as Xanthan are insensitive to shear even when high shear is applied to xanthan solutions to attain proper mixing. In another side synthetic polymers are very sensitive to shear and thus it is easy to achieve proper mixing. High variation in polymer mobility is observed near the wells the well where fluid viscosities are large.

Even though for shear thinning fluids like polymers their rheological properties are often possible to be represented by power-law model as defined by equation 10 (Yugal, 2011).

$$\mu = K\gamma^{(n-1)} \tag{10}$$

3.3.5.5 Polymer Stability.

Polymers are mostly useful in the EOR applications due to its property that small concentrations of polymer can increase the viscosity of an aqueous solution significantly. To be used in IOR applications Polymer solution should be stable enough to withstand reservoir conditions for the time expected to remain in the formation. It is necessary to understand the polymer stability at reservoir temperature and in the reservoir brine when it comes to the injection process. As a result of its elastic behavior HPAM is subjected to mechanical degradation it will easily degrade by high shear rates in the reservoir.

In offshore operations it has some restrictions since PAM is stable up to 62^0C with sea water salinity and up to 90^0C for normal salinity water. Biopolymers are prone to bacterial attack in low temperature zones in the formation.

Xanthan stability is said to be from 70^0C and above 90^0C, while scleroglucan is stable above 105^0C. Biological degradations is prevented by using biocides such as formaldehyde with concentrations between 500 to 1000ppm (Sarkar, 2012).

3.3.6 Application of Polymers in Oil Industry.

When compared to water injection it has been discovered that there is significantly improve in oil recovery when polymer is used. Polymer reduces the adverse the effect of permeability variations. The only common polymer used in the field is Hydrolysed polyacrylamide (HPAM) and can withstand a temperature of about 185^0F depending on the brine hardness. The most important characteristics for reservoir heterogeneity and mobility ratio of reservoir fluid effectiveness is the permeability reduction which is the result of polymer flooding. Modified polymers such as HPAM- AMPS which are considered as co-polymers are very useful and stable to higher temperature are also available (Sarkar, 2012).

3.5.7. Prediction of Polymer Mobility in the Shear-Thickening Region

Polyacrylamides show an unusual flow behavior in a reservoir rocks at high frontal-advance rates. Shear-thickening behavior is observed when the flowing fluid become more viscous resulted from increase in flow rate. This tendency is caused by viscoelastic nature of polyacrylamide (Lake, 1989).

3.3.7. Polymer Flood Simulation Model in the Eclipse 100.

In the reservoir the flow of polymer solution is expected to produce no influence on the flow of hydrocarbon phases. Thus, the description of hydrocarbon phases in the model is achieved by the normal black-oil equations. As polymer has to be injected, addition of equations to describe the polymer and brine flows in the finite difference grid are required with modification for the standard water equation. The equations 10,11,12,13, 1nd 14 describe the flow of water, polymer, and brine in the reservoir (Schlumberger, 2015).

$$\frac{d}{dt}\left(\frac{VS_W}{B_r\,B_w}\right)=\sum[\frac{Tk_{rw}}{B_w\mu_{w.eff}R_k}(\delta P_{w-\rho_w g D_z]+Q_w} \qquad 10$$

$$\frac{d}{dt}\left(\frac{V^*S_wC_p}{B_rB_w}\right)+\frac{d}{dt}\left(V\rho_r C_p^a\,\frac{1-\emptyset}{\emptyset}\right)=\sum[\frac{Tk_{rw}}{B_w\mu_{w.eff}R_k}(\delta P_{w-\rho_w g D_z]C_p+Q_w}\,C_p \qquad 11$$

$$\frac{d}{dt}\left(\frac{VS_wC_n}{B_rB_w}\right)=\sum[\frac{Tk_{rw}}{B_w\mu_{w.eff}R_k}(\delta P_{w-\rho_w g D_z]+C_nQ_w} \qquad 12$$

$$V^* = V(1-\frac{S_{dpv}}{S_w}) \qquad 13$$

$$V^* = V(1-S_{dpv}) \qquad 14$$

In the model the density and formation volume factor of the aqueous phase are assumed to be independent of the salt and polymer concentrations. It also represents the polymer solution, reservoir brine and injected water as miscible components in the aqueous phase, in which the degree of mixing is based on viscosity terms in the conservation equations. The viscosities of the fluids depend on the local concentrations of salt and polymer in the solution (Schlumberger, 2015).

3.4 Surfactant Flooding:

Surfactants is the short term of surface-active agents which define as the chemical substances which adsorb on or concentrate at a surface or fluid/fluid interface when at low concentration in the system. Surfactants adjust significantly the interfacial properties of the system mainly by reducing the surface tension or interfacial tension (IFT) (Green & Willhite, 1998).

Surfactants consist of hydrocarbon part which is nonpolar and a polar part (ionic) in their often-common arrangement. In the molecular structure of the surfactants the nonpolar part is often known as the tail while the ionic part is called the head as indicated in figure 17. The part of the tail can be either a branched or a straight chain. The two portions are respectively called lithophilic and hydrophilic moieties. Individual portion of the structure is known as a moiety while the entire molecule can be called amphiphile due to the presence of nonpolar and ionic moieties (Lake, 1989).

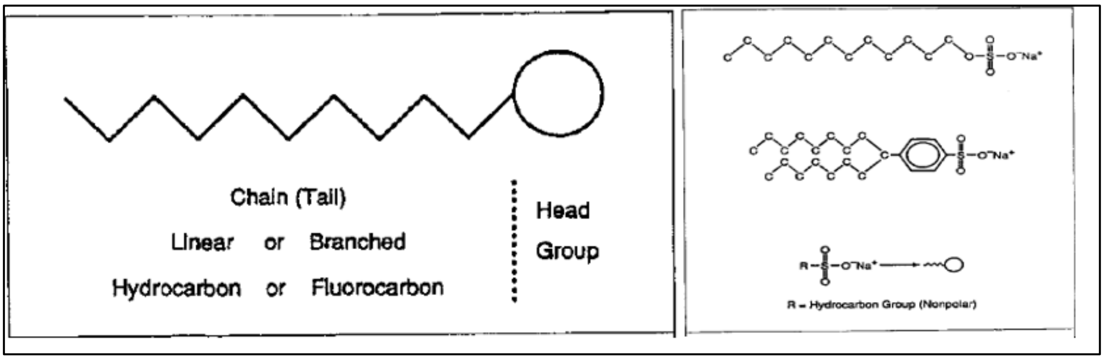


Figure 17:Description of surfactant molecules *(Lake, 1989)* .

3.4.1 Classification and Structure of Surfactants

According to (Lake, 1989) the classification of surfactant is based on the ionic nature of the head group which are anionic, cationic, nonionic and zwitterionic as seen in Figure *18*.

3.4.1.1 Anionic.

As a result of negative charge on its head group, this type of surfactants is known as anionic surfactants. They are used frequently in chemical EOR processes since they relatively show low adsorption on sandstone rocks whose surface charge is negative. In carbonate rocks they are strongly adsorbed since carbonate possesses positively charged surface. Structurally anionic is sodium dodecyl sulfate ($C_{12}H_{25}SO_4^-Na^+$) (Green & Willhite, 1998) as described in *Figure 19.*

3.4.1.2 Nonionic.

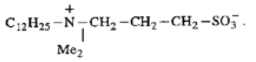
Nonionic surfactants have no charge as a result they do not ionise in the aqueous solution. The structure has large head group than tail group. Primarily they serve as cosurfactants to improve the phase behaviour of the system. Their ability to reduce IFT is not good when compared to anionic surfactants, though they are more tolerant of high salinity brine (Sheng, 2011). To increase the tolerance to salinity, a mixture of anionic and nonionic is usually used. Example of nonionic is dodecylhexaoxyethylene glycol monoether ($C_{12}H_{25}OCH_2CH_2]_6$ OH) (Green & Willhite, 1998).

3.4.1.3 Cationic Surfactants.

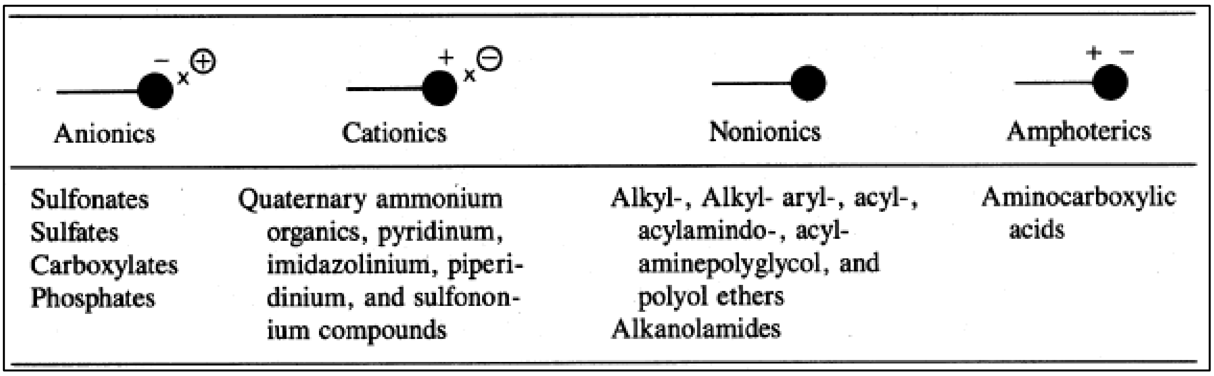
They are positively charged and adsorb strongly on the sandstone rocks, as the results they are not applied in sandstone formations instead can be potential in carbonate reservoirs to change the wettability system from oil-wet to water-wet (Sheng, 2011). It ionises in aqueous solution which make the head group positive. Dodecyltrimeththylammonium bromide ($C_{12}H_{25}N^{+}Me_3Br^{-}$) (Green & Willhite, 1998)

3.4.1.4 Zwitterionic.

According to (Lake, 1989) amphoteric is also used as another name for this surfactant type. It has made up of two active groups, which can be nonionic-anionic, nonionic-cationic, or anionic-cationic. They are tolerant to temperature and salinity which make them to be expensive (Sheng, 2011). Example of the amphoteric surfactants is given by 3-dimethyldodecylamine propane sulfonate.

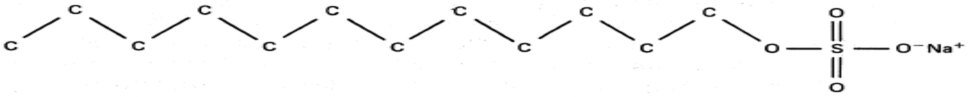


$C_{12}H_{25}-\overset{+}{\underset{Me_2}{N}}-CH_2-CH_2-CH_2-SO_3^{-}$.

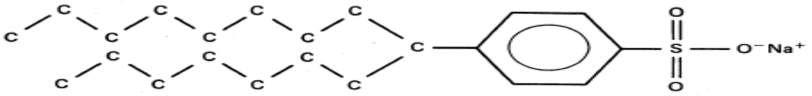


Anionics	Cationics	Nonionics	Amphoterics
Sulfonates Sulfates Carboxylates Phosphates	Quaternary ammonium organics, pyridinum, imidazolinium, piperidinium, and sulfononium compounds	Alkyl-, Alkyl- aryl-, acyl-, acylamindo-, acyl-aminepolyglycol, and polyol ethers Alkanolamides	Aminocarboxylic acids

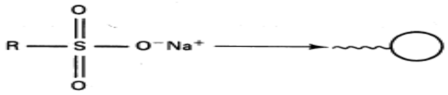
Figure 18: Surfactant types and description (Lake, 1989)



(a) Sodium dodecyl sulfate



(b) Texas no. 1 sulfonate



R = hydrocarbon group (nonpolar)

(c) Commercial petroleum sulfonates

Figure 19:Surfactant molecular structures (Lake, 1989)

3.4.2 Methods Used to Characterise Surfactants.

Sulfonated hydrocarbons are the most useful surfactants in surfactant flooding. These hydrocarbons sulfonates are resulted when an intermediate-molecular-weight refinery stream is sulfonated, and synthetic sulfonates are the product obtained after a relatively pure organic compound is sulfonated. For low salinity (<2 to 3%wt NaCl) petroleum and crude oil sulfonates have been used. These types of surfactants mostly have been used since they are effective at achieving low IFT, relatively less expensive, and chemically stable. The order of increasing stability of sulfonates is described indicated below (Sheng, 2011).

Petroleum sulfonates<alpha olefin sulfonates<alkylarysulfonates.

Although sulfate moieties decompose rapidly at temperature above 100^{o}C, the surfactants which are stable above 200^{o}C are almost exclusively sulfonate groups. (Green & Willhite, 1998). Some methods to characterise surfactants are presented below.

3.4.2.1 Hydrophile-Lipophile Balance.

Hydrophile-lipophile balance(HLB) number is used to characterise surfactants as it indicates the tendency to solubilize in oil or water resulting into the formation of water-in-oil or oil-in-water emulsions. Low HLB numbers are given to surfactants which are easily soluble in oil and tend to form water-in-oil emulsions. In the presence of low salinity reservoir, surfactant with low HLB number must be selected. Such a surfactant can make middle-phase microemulsion at low salinity. In other side a high HLB should be designated when the reservoir salinity is high. Such a surfactant is more hydrophilic and can make middle-phase microemulsion at high salinity (Sheng, 2011).

HBL can be determined by calculating values for various regions of the molecule by using Griffin’s equation for nonionic surfactants as represented by equation 15.

$$HBL = {}^{20MWh}/_{MW} \qquad 15$$

Where

MWh is the molecular mass of the hydrophilic portion of the molecule

MW is the total molecular mass of the molecule.

An HBL value of zero (0) corresponds to completely hydrophilic molecule and that of 20 represents a molecule made up of complete hydrophilic components. HBL value is used to predict surfactant properties (Sheng, 2011).

3.4.2.2 Critical Micelle Concentration and Craft Point.

As one of the characteristics of surfactant, critical micelle concentration(CMC) is defined as the concentration of surfactants above which micelles are spontaneously formed. When surfactants are introduced into the system, they will initially partition into the interface, reducing free energy of the system by lowering the energy of the interface and removing the hydrophobic parts of the surfactant from contact with water. Afterward, as surface coverage by the surfactants increases and the surface tension decreases, surfactants start aggregating into micelles, resulting in decreasing the system free energy by reducing the contact area of the hydrophobic parts of surfactant with water. After attaining CMC any addition of further surfactants will just raise the number of micelles as indicated in figure 20. (Lake, 1989)

In other words, before reaching the CMC, the surface tension decreases gradually with concentration of the surfactant but when reaching CMC surface tension stays more or less constant (Green & Willhite, 1998).

Kraft temperature (point) or critical micelle temperature is another parameter related to CMC and it is defined as the minimum temperature at which surfactants form micelles. Below Kraft point no micelles can form. For nonionic surfactant, cloud point is a related parameter which is the temperature at which phase separation occurs, resulting to cloudy. This tendency is a characteristic of nonionic surfactants with polyxyethylene chains with reverse solubility against temperature change in water, thus cloud out at some point as the temperature is raised (Lake, 1989).

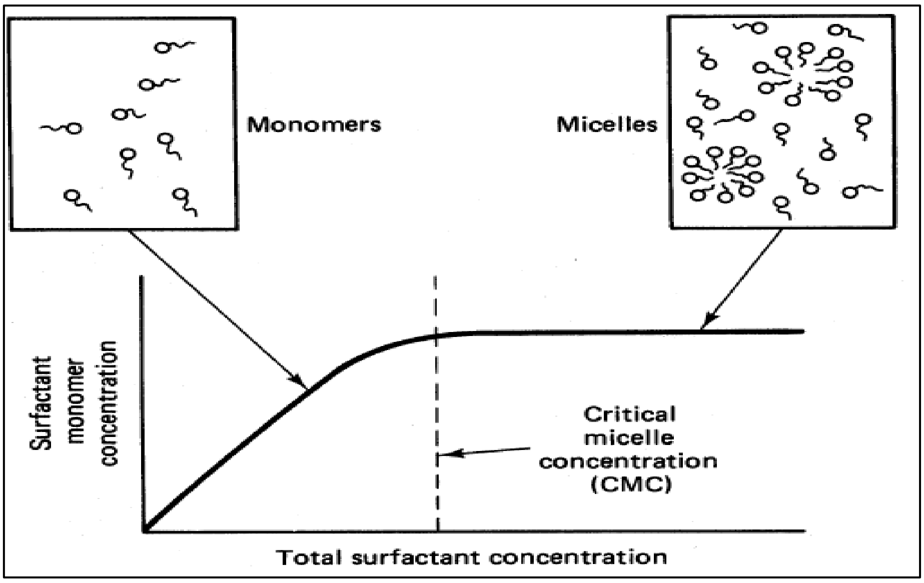


Figure 20:Schematic definition of critical micelle concentration (CMC) (Lake, 1989)

3.4.2.3.Solubilization Ratio.

Solubilization ratio is one of the theories used to guide new surfactant design and explain surfactant phase behavior. It is a technique of making insoluble material soluble in a given medium. For oil (water) it is defined as the ratio of solubilized oil(water) to the surfactant volume in the microemulsion phase. Huh (1979) formulated that solubilization ratio is closely related to IFT. The IFT attains its minimum when the solubilization for oil is equal to that for water. (Sheng, 2011).

3.4.2.4 R-Ratio.

This is another factor which has been used in defining the required surfactant characteristics for injection in a particular reservoir system. It explains the interaction between the lipophilic tails (A_{CO}) and hydrophilic heads (A_{HCO}) mathematically it can be represented by equation 16. In this case it can be observed that if the interaction between oil molecules and surfactants molecules is strongly attractive, then the surfactant has affinity to oil phase (Sheng, 2011).

$$A_{CO} = A_{LCO} + A_{HCO} \qquad 16$$

Consequently, for strong attraction between water molecules and surfactant molecules, the surfactant has affinity to the water phase. Thus, the interaction is defied by equation 17.

$$A_{Cw} = A_{LCw} + A_{HCw} \qquad 17$$

When the hydrophilic head is neglected as lipophilic tails are oriented in the oil phase, similarly for water system the hydrophilic are oriented to the water phase, the lipophilic can be eliminated.

Thus, the surfactant affinity to oil or water is described by R-ratio represented by equation 18 (Sheng, 2011).

$$R = {}^{A_{CO}}/_{A_{CW}} \qquad 18$$

3.4.2.5 Packing Factor.

Packing Factor is defined as the ratio of the volume occupied by the hydrophobic group in the micellar core to a cross-section area occupied by the hydrophilic to the length of hydrophobic group. To attain the minimum IFT the packing factor should be 1. Equation 19 is used for determination of packing factor

$$\Phi = \frac{V}{a_o L_c} \qquad 19$$

Where a_o is the cross-sectional area occupied by the hydrophilic at micelle surface and

L_c is the length of the hydrophobic group.

3.4.3 Principles of Surfactants.

Some of the important functions of surfactants are, first it should reduce the interfacial tension as a results, oil and water can create emulsion and flow in continuous phases. In the presence of water mixed with oil, the molecules of surfactants tend to diffuse in water and adsorb at the interfaces between air and water or at the interface between oil and water. As the insoluble hydrophobic group might extend out of the bulk water phase, into oil phase or into air, the water-soluble head group remains in the water phase. By doing this the surfactant molecules modify the surface properties of water at the water/air or water/oil interface as seen in figure 21.

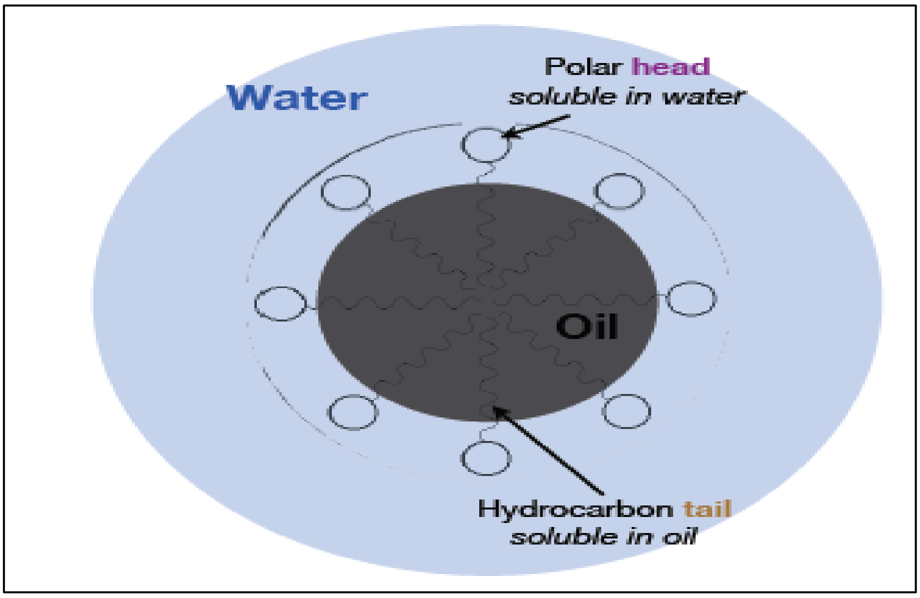


Figure 21: Principles of surfactant in the system (Sarkar, 2012)**.**

Two immiscible fluids such as oil and water may be dissolved by using surfactants, by emulsion process. To achieve this, surfactants from micelles spontaneously water when the surfactant concentration is high enough. The structure of micelle can be spherical, cylindrical or a bilayer. As shown in figure 19, the hydrophilic part dissolve in water phase while the hydrophobic part dissolve in oil phase. The barrier between the two phase is created by a micelle thus, the two phases cannot come in direct contact to each other. Surface tension between the two phases will decrease with increasing amount of surfactants up to a CMC. Surface tension will remain unchanged at CMC in which the maximum limit is attained (Yugal, 2011) .

3.4.4 Mechanism of Surfactants.

The main function of surfactants is to reduce the interfacial tension between oil and water by blending them. As a result, it changes the wettability of the system from oil wet to water wet applied in surfactant imbibition EOR in fractured carbonate reservoirs. The decrease in IFT will improve the microscopic displacement efficiency resulting to increased oil recovery. Sometimes to achieve the desired volumetric sweep efficiency by mobility control, polymers are added after surfactant injection (Yugal, 2011).

The objective of injecting surfactant is to recover capillary- trapped residual oil which has been left behind after waterflooding. When surfactant solution is injected into the system the residual oil may be forced to move through a strong reduction in IFT between oil and water (Sarkar, 2012).

Figure 22 describe the typical plot of residual saturation as a function of capillary number Nc, it is known as the Capillary Destruction Curve (CDC). The figure describes that surfactant flooding must perform best in a water wet system.

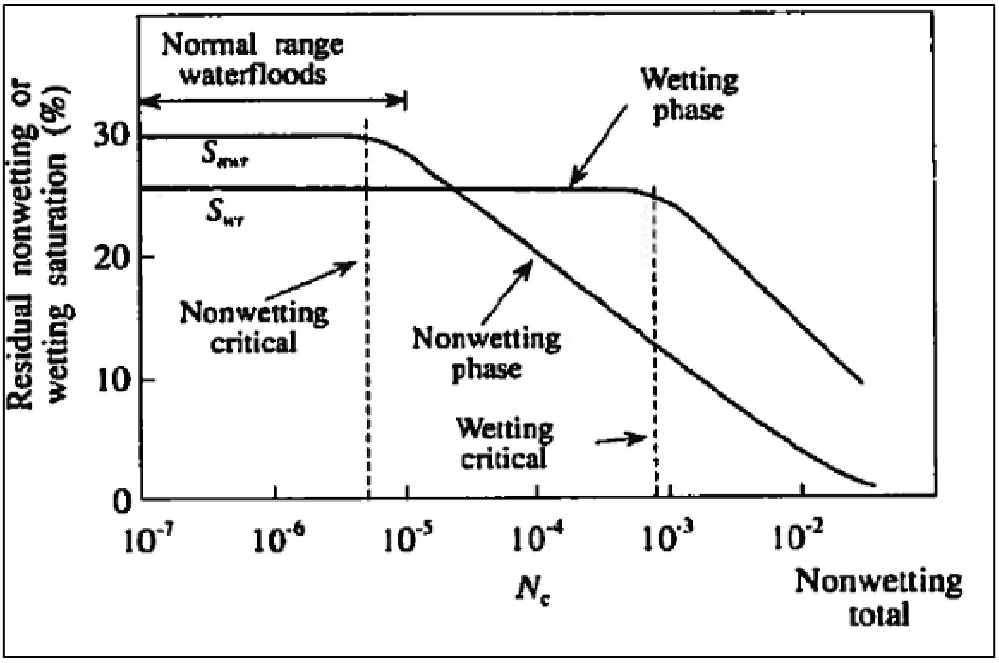


Figure 22:Wettability effect on residual saturation of wetting and non-wetting phase *(Yugal,* 2011*)*

3.4.5 Basic Parts for Designing Surfactant Flooding

3.4.5.1 Capillary Number.

Capillary number is the ratio of relative viscous forces versus surface tension acting across an interface between two immiscible phases. Though there are a lot of definitions, mathematically capillary number is represented by equation 20.

$$N_C = \frac{\mu u}{\sigma} \qquad 20$$

Where N_C is the capillary number,

u is the effective flow rate and

σ is an interfacial tension.

When the capillary number increase the implication is the decrease in the residual oil saturation, as a result improve in the oil recovery.

Capillary number increase can be attained by increasing the viscosity of the displacement fluid or an increase in the velocity of the displacement fluid, which may be not valid for field scale. In surfactant flooding large capillary number is obtained as a result of reduction in interfacial tension between water and oil (Teknica, 2001).

3.4.5.2 Mobility control in Chemical injection.

The sweep efficiency of the system is attained when there is a favorable mobility ratio between the chemical slug and the oil bank displaced by the slug. If the mobility ratio is not suitable fingering might happen into the oil bank, as a result dispersion and mixing may reduce it ineffective. To attain the mobility control process, in most cases the viscosity of the chemical slug is adjusted so that the effective mobility resulted will be less than or equal to the design mobility.

For average water saturation close to 1-s_{orc} the mobility of the chemical to be injected is determined using equation 21 (Green & Willhite, 1998).

$$\lambda_c = \frac{k_{rw \quad at\,1-s_{orc}}}{\mu_c} \qquad 21$$

3.4.6. Surfactant Simulation Model in Eclipse 100.

3.4.6.1 Simulation Model in Eclipse 100.

The surfactant distribution is modelled by solving conservation equation for surfactant within the water phase. The concentrations of surfactant are rationalized fully-implicitly after each time step when oil, water and gas flows have been calculated. The surfactant input to the formation is specified by concentration of the surfactant in injected water and only occurs in water phase. Some of the important parameters described in surfactant simulation model are described as follows.

3.4.6.2 Calculation of the Capillary Number.

Capillary number is a dimensionless parameter which represent the ratio of viscous forces to capillary force exerted between oil-water interface. In simulation model capillary number is computed using equation 22.

$$N_c = \frac{C_N}{C_D} \, \| \frac{T \triangle P_o}{A} \| \, \frac{1}{\sigma_{ow}}, \qquad N_C = \frac{K \nabla P_o}{\sigma_{ow}} \qquad 22$$

3.4.6.3 Relative Permeability Model.

In surfactant flooding, the relative permeability model permits a conversion of the phase from immiscible relative permeability curves at low capillary number to miscible relative permeability curve at high capillary number. Transition among these curves are achieved and described in the transition as the function of log10 of the included capillary number.

Two steps are involved in calculating the relative permeability to be used at a given value of the miscibility function. First step is achieved by interpolation of the end point saturation curves and scales both immiscible and miscible curves using weighting factor F. Secondly the relative permeability are looked up on the curves as the function of grid block saturation as a result the final relative permeability is obtained by interpolating the two-value using weighting factor F. Water relative permeability krw and oil-to-water relative permeability are determined using this procedure. Figure 23 is used for relative permeability calculation.

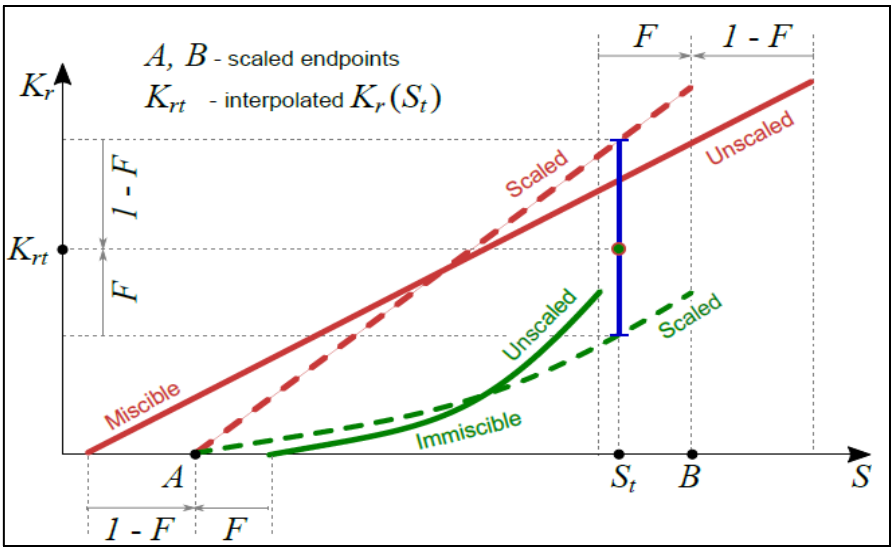


Figure 23: Relative permeability calculation curve (Schlumberger, 2015)

Weighting factor F is calculated by using equation 23.

$$F = F_{kr}(logN_C) \qquad 23$$

3.4.6.4 Capillary Pressure.

The capillary pressure between water and oil will be reduced with increase in surfactant concentration, but the residual oil saturation will be reduced only when there is a reduction in oil-water capillary pressure. Mathematically the oil water capillary pressure is given by equation 24 and 25.

$$P_{cow} = F_{cp} P_{cow}(s_w) \qquad 24$$

$$F_{cp} = \frac{\sigma_{ow(C_{surf})}}{\sigma_{ow}^{(0)}} \qquad 25$$

C_{surf} is surface tension at a given surfactant concentration obtained from table supplied by SURFST.

$\sigma_{ow}^{(0)}$ is the surface tension at zero concentration

F_{cp} is capillary pressure multiplier.

$P_{cow}(s_w)$ is the capillary pressure from the immiscible curve initially scaled to interpolated end-points calculated in the relative permeability model.

In Eclipse 100 when the salt-sensitivity optional has been activated the capillary pressure multiplier becomes a function of salt concentration as observed in equation 26.

$$F_{cp} = \frac{\sigma_{ow}(c_{surf}, c_s)}{\sigma_{ow}(0, c_s)} \qquad 26$$

Where

$\sigma_{ow}(c_{surf}, c_s)$ is the surface tension at a given surfactant and salt concentrations.

$\sigma_{ow}(0, c_s)$ is the surface tension at zero surfactant concentration and present salt concentration.

3.4.6.5 Water PVT Properties.

One of the function of surfactant is to modify the viscosity of pure or salted water input using the key word PVTW or PVTWSALT. The surfactant viscosity input as a function of concentration is used to determine the water-surfactant solution viscosity using equation 27.

$$\mu_{ws}(C_{surf}, P) = \mu_w(P) \frac{\mu_s(C_{surf})}{\mu_w(P_{ref})} \qquad 27$$

For active brine option keeping polymer option non-active, the equation becomes the function of salt concentration c_s as represented by equation 22 below.

$$\mu_{ws}(C_{surf}, P, c_s) = \mu_w(P, c_s) \frac{\mu_s(C_{surf})}{\mu_w(P_{ref}, c_{sref})} \qquad 28$$

From equation 28, it is observed that the viscosity of water surfactant solution varies from pure water though in low surfactant concentration it is assumed to same viscosity for the water surfactant solution as pure water (Sarkar, 2012).

3.4.6.6 Adsorption Treatment in Eclipse Model.

Surfactant adsorption is assumed to be very sudden, and the amount of surfactant adsorbed is the function of surfactant concentration distributed. To determine the quantity of surfactant adsorbed equation 29 is often used.

$$Mass\ of\ adsorbed\ surfactant = PORV.\frac{1-\phi}{\phi}.MD.CA(C_{surf}) \qquad 29$$

Where PORV is the pore volume of surfactant viscosity,

ϕ is the porosity,

MD is the mass density of the rock and

$CA(C_{surf})$ is the adsorption isothermal which is the function of local surfactant concentration in solution.

The surfactant adsorption may be specified by keyword ADSORP with SURFACT as an augment. The key word ADSORP stipulates coefficients for a broad, analytical adsorption isotherm which allows for dependencies of adsorption on rock permeability and effective brine salinity. (Schlumberger, 2015)

3.4.6.7 Surfactant Retention.

To determine the success or failure of a surfactant injection process, it is necessary to control the retention of the surfactant in the formation. Normally the surfactant retention has been recognized as precipitation, adsorption, and phase trapping mechanisms. The resulting effects of these mechanisms in retention of surfactant in the reservoir is the deterioration of the slug chemical composition, resulting in poor displacement efficiency. The retention of surfactant in the reservoir is affected by the surfactant type, equivalent weight of surfactant, concentration of surfactant, rock mineral, clay content, temperature, pH, and flow rate of the solution.

The concentration of surfactant is proportional to the surfactant retention (Yugal, 2011). The surfactant precipitation is caused by the presence of divalent cations ($Ca^{2+,}$ Mg^{2+})

3.4.6.8 Adsorption.

The presence of charge in most of reservoir rocks are resulted by the various mineral found at the surface. Minerals such as calcite, dolomite and clay have positive charge on their surface at neutral pH of the brine while quartz (silica), kaolinite are negative charge. The surfactants adsorption at the solid/liquid interface is achieved by electrostatic interaction between charged solid surface (adsorbent) and the surfactant ions (adsorbate). Surfactants adsorb onto the mineral surface by ion exchange, ion pairing and hydrophobic bonding mechanisms.

In sand stone surface nonionic surfactants are highly adsorbed than anionic surfactants while for calcite is opposite. From adsorption considerations nonionic surfactants may be suitable in carbonate reservoir (Green & Willhite, 1998).

The adsorption model in a negatively charged surfactant onto a positive adsorbent charged sites represented by s-shape as described in figure 24. Four different parts which describe different adsorption modes are discussed as follow.

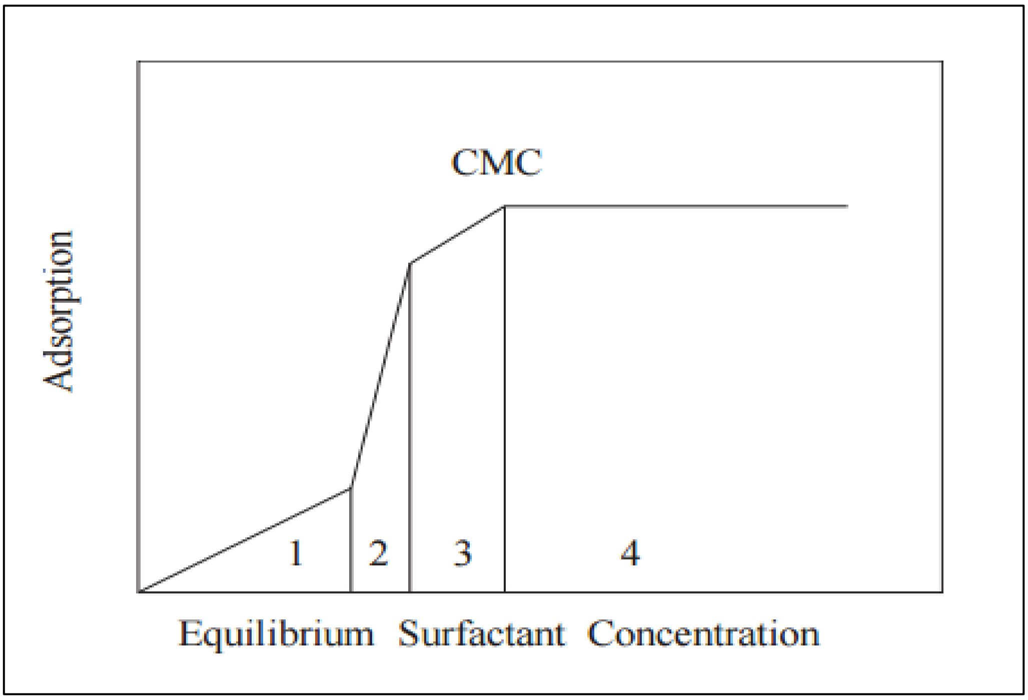


Figure 24: Schematic S-shaped adsorption curve for anionic surfactant (Kleppe & Skjaeveland, 1992).

Region 1: in this part surfactant is mostly adsorbed by ionic exchange and shows a linear relationship between the material adsorbed and equilibrium concentration.

Region 2: Sudden raise in adsorption as a result of interaction between the hydrophobic chains of the oncoming surfactant and the surfactant that already has been adsorbed.

Region 3: There is a decrease in surfactant adsorption resulted by the overcomed electrostatic repulsion between surfactant and similarly charged solid.

Region 4: A constant adsorption is attained above the critical micelle concentration (CMC), which implies that surfactant adsorption will not increase on the surface.

Interfacial tension between oil and water decreases until CMC is achieved. Some of the parameters that affect the plateau of the system are salinity, pH-value, temperature, and wettability. When the reservoir salinity increases the plateau, adsorption will increase on other hand decrease in pH may lead to an increase in adsorption. It can be observed that the surfactant adsorption is inverse proportional with temperature changes (Sheng, 2011).

3.4.6.9 Phase Trapping.

Phase trapping is resulted by mechanical trapping, phase partitioning or hydrodynamic trapping. The mechanism of phase trapping and the magnitude of surfactant loss due to phase trapping might be different depending on the multiphase conditions. (Hirasaki et al.,2008) reported that surfactant phase trapping may be more imperative than surfactant adsorption. Though the phase trapping mechanism is complex, it is well recognized and accepted that phase trapping is related to types of microemulsion.

At higher concentration the onset of phase trapping with surfactant flooding process occur as a result it forms upper- phase microemulsion so that surfactant might be trapped in the residual oil.

3.5 Low Salinity Waterflooding.

Low salinity waterflooding is the process of injecting water with low salinity compare to the reservoir brine to improve the oil recovery. Observations by various experiments in the past years have shown that injection of low salinity water results to an improvement of oil recovery (production) compare to injection of water with high salinity or reservoir salinity (Berg, et al., 2009).

Tang and Morrow reported this method with modest growth in resistance to flow only. From there a lot of laboratory experiments and analysis have been reported with the chance and complications associated with identifying, reproducing, and explaining the effect of low salinity effect (Makame, et al., 2016) LSE (Norman & Buckley, 2011).

This indicates that the necessary conditions for LSW injection are not well known (Ramez A & Hisham A, 2011). In most case the injection water has less than 3000 ppm of dissolved solids which is very different compare to higher salinity or normal sea water salinity which is 30,000 ppm (Makame, et al., 2016).Although the method has already applied in various fields, the microscopic mechanism is so far complicated. The proposed mechanism by various researchers is that low salinity water results to the change of the reservoir wettability with the consequence of releasing oil which was formerly remain attached to the clay mineral (Berg, et al., 2009).

Low salinity water injection is performed either as secondary or tertiary technique, at initial water saturation (s_{wi}) it is categorised as secondary approach in another side at residual oil saturation (s_{or}) it is used as tertiary means of recovery (Shiran, 2014). (Norman & Buckley, 2011) reported that at initial water saturation LSW the recovery factor was 6% of OOIP higher than for either high salinity (HS) or medium salinity (MS) injection and increase up to 25% over higher salinity water flooding at residual oil saturation s_{or}.

Even though, presence of connate water, creation of mixed wettability and substantial clay fraction were reported by Tang and Morrow (1999) as the necessary conditions for low salinity effect.

3.5.1 Mechanisms of Low Salinity Waterflooding.

3.5.1.1 Double layer expansion (DLE).

Instead of decrease in the divalent ion concentration DLE is based on the thought that to attain the low salinity effect, reduction in total salinity is required.

An electrical double interface is formed in an electrolyte with negatively charged surface as seen in figure 25. The distance from the surface where surface charge is exerted, resulting into concentration and distribution variation from the total fluid is known as the double layer thickness. The presence of negatively charged oil-water interface and the clay surface with petroleum is the consequence of double layer. Brine with high ionic strength, will have small double layer thickness which allows oil and clay to become closer for interaction with active oil components, resulting in adsorption which change the system to an oil-wet condition. The double layer expands and overlap when low salinity water injection is performed.

The binding force will be overcomed by repulsion of similar charged oil-water interface and clay surface at sufficiently low salinity leading to oil desorption and finally more water-wet system resulting to the release of oil as shown in figure 26 (Kuznetsov, et al., 2015).

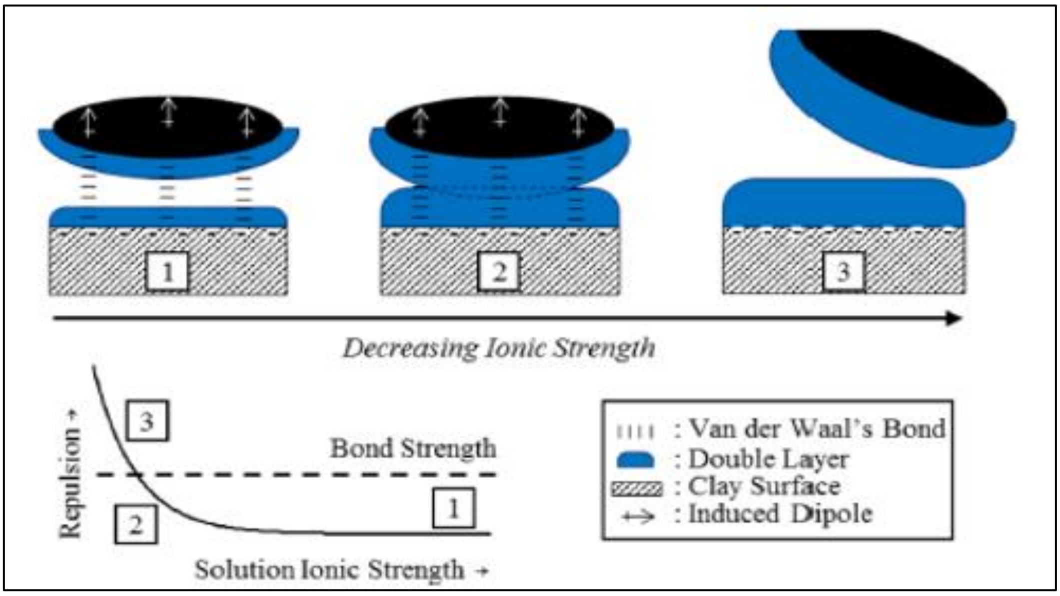


Figure 25: Hydrocarbon release by double layer expansion ((Kuznetsov, et al., 2015)

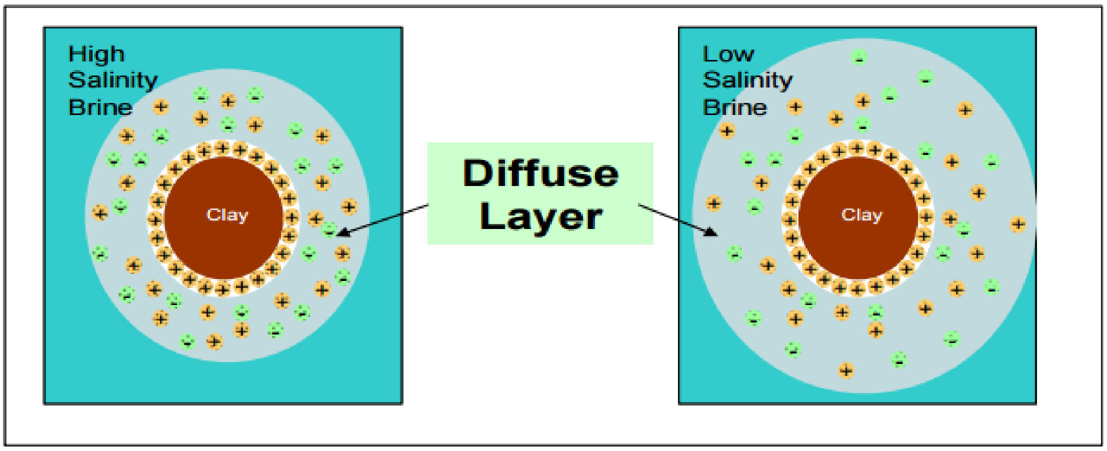


Figure 26: Low salinity effect resulted by double layer expansion *(* (Lee, et al., 2010)

Increase in PH of the brine water is the effect resulted by the thickness of double layer. (Kuznetsov, et al., 2015). Observation from produced brine shows PH changes which indicates there is chemical interaction among the two fluids (injected water and connate brine). In some cases where initial PH is low, it is hard to reach the required level of PH which could affect the wettability or lower the mechanism of interfacial-tension during flooding. Experimentally it has been reported that mobilization of fines achieved by frequent low salinity water injection on the same core sample has resulted on less benefit.

3.5.1.2 Multi-component ionic exchange (MIE).

In multi-component ionic exchange mechanism, it has been proposed that during low-salinity water injection, ions exchange occur at the clay surface, eliminating adsorbed organic compounds and organometallic complexes which formed with multivalent ions directly.

The ionic exchange leads to organic matter desorption, resulting to an increase in water-wetness. A lot of laboratory work have been conducted based on injecting fresh water into salt water aquifer and the observation show there are some decrease of calcium concentration to the injected water signifying the adsorption of the ions since initially the ions like sodium and calcium are said to be in equilibrium with the pore wall see figure 27 (Kuznetsov, et al., 2015)

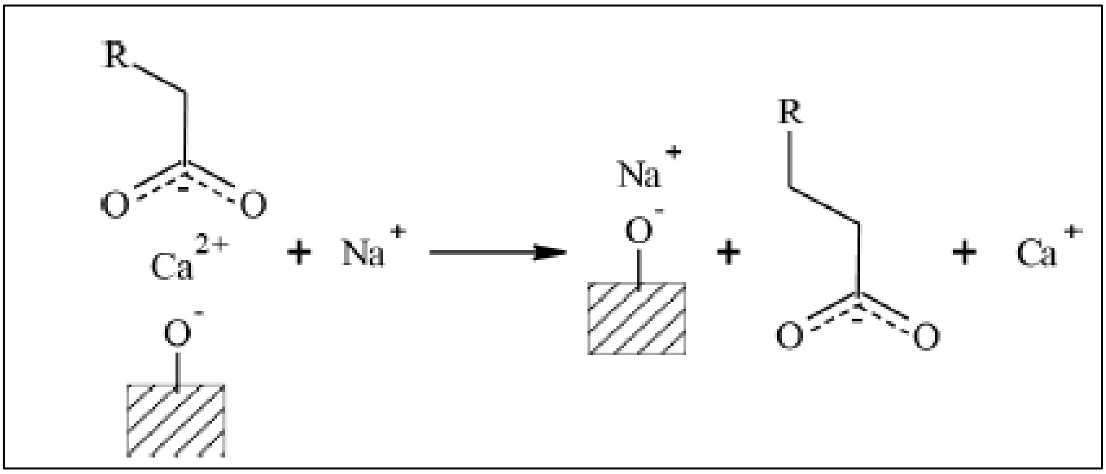


Figure 27: Hydrocarbon release by multicomponent ionic exchange ((Kuznetsov, et al., 2015)

3.5.1.3 Wettability Alteration.

The modification of wettability of the system to become more water-wet has proven to be the most often proposed mechanism for improving oil recovery by low salinity waterflooding. The principle behind the mechanism is that, the system (reservoir rock) becomes more water-wet resulting in releasing the oil that was remained attached at the rock surface, reducing reducible oil saturation (s_{or}) and finally increase the recovery of oil. The process of change in wettability by considering interaction between water, crude oil, and rock have been reported, even though the agreement on this is a challenging conclusion. (Morrow et al,2011).

3.5.1.4 Fine Migrations.

Diversion of microscopic flow resulted from fines mobilization has been proposed as one of the low salinity mechanism which affect the recovery by waterflooding. Mobilization and destabilization of clays and silt particles are the consequence of low salinity water injection. The effect is that the released particles block the pore throats and change the direction of flow to unswept area resulting in increased oil recovery. In other way the released mixed wet particles alter the wettability by uncovering of new water-wet rock surface (. (Tang & Morrow, 1999).

3.5.2 Secondary and Tertiary Modes of Low Salinity waterflooding.

Low salinity water injection has been applied on both cases (secondary and tertiary) to evaluate the effect of the flooding timing based on low salinity effect (LSE). Low salinity at initial water saturation sw_i is referred as secondary model. (Norman & Buckley, 2011)

In secondary model application the low salt water (LSW) is injected at the beginning just after the end of natural drive has been reached.

Tertiary mode is performed at residual oil saturation s_{or} after high salinity waterflooding has been employed. Since in most cases the mature oil reservoirs are formerly at high salinity water residual oil saturation state, thus EOR experts have been highly concerned with the application of LSW and observation of LSE (Shiran, 2014).

To compare the secondary and tertiary model of low salt waterflooding for crude oil /sandstone combinations, Zhang and Morrow (2006) performed an experimental work. The observation presented an improved oil recovery in both cases. Comparable experimental studies were performed by Webb et al. (2005 and 2006), Ashraf et al. (2010), Rivet et al. (2010), Gamage and Thyne (2011), Winoto et al. (2012), and Nasralla and Naser-El-Din (2012), all studies indicated higher improved oil recovery by low salinity waterflooding in the secondary mode compared to the tertiary mode. (Shiran, 2014)

3.6 Economic Evaluation.

To achieve the economic evaluation for the surfactant flooding, polymer injection and low salinity water flooding a general net present value (NPV) analysis is commonly applied. Net present value (NPV) is defined as total amount of the present values of the isolated cash flows (Sarkar, 2012). In discounted cash flow analysis NPV is applied as a standard technique which implies the time value of money to evaluate long-term projects. It compares the values of money today with the same value of money in the future including by considering inflations (Yugal, 2011). When the resulted NPV of the project is positive the project is profitable, and it should be accepted, but when the NPV resulted from the cash flow is negative the project must be rejected. Mathematically NPV is expressed by equation 30.

$$NPV = \sum_{i=1}^{n} \frac{R_n}{(1+r)^n} - R_o \qquad 30$$

CHAPTER 4.

4.0 ECLIPSE SIMULATION MODEL.

4.1 Description of the Reservoir Simulation Model.

Eclipse 100 has been used to model the Statfjord I-1 segment of the Gullfaks field with a fully implicit three phase (water, oil and gas) three dimensions black oil simulator. The Statfjord I-1 reservoir model composed of 30 grids in the X-direction, 60 grids in the Y-direction and 12 grids in the Z- direction. The visual of the reservoir from simulation model of the Statfjord I-1 segment is shown in figure 28. This visual was taken from ResInsight after simulation of the input grid file obtained from eclipse result file. The reservoir and fluid properties of the Statfjord I-1 segment are described in table 3 obtained from reservoir management report of Gullfaks.

Table 3: Description of reservoir rock and fluid properties of Statfjord I-1 field (Talukdar & Instefjord, 2008).

Fluid properties	**Parameter**	**Unit**
Initial pressure	318	Bars
Bubble point	250	Bars
Gas oil ratio	162	Sm^3/Sm^3
Oil formation volume factor at bubble point	1.26	m^3/Sm^3
Oil viscosity at bubble point	0.73	CP
Porosity of the Reservoir	0.28	
Permeability	0.5 - 5	Darcy
Oil density at bubble point	0.844	g/cm^3
Gas formation volume factor	0.0044	m^3/sm^3
Initial temperature	80	^0C
Salt concentration of the formation water	49000	ppm

The history matched simulation model (base case) composed of three wells of which two wells (A-36 and C-16) and one injector well named A-41 as indicated in figure 34. The simulation of the base case (history match) was run from May 1992 up to January 2001 as shown in figure 36.

4.2 Reslnsight Description.

ResInsight is an open source, cross-platform 3D visualization and post tool for Eclipse reservoir models and simulations. The system also comprises a frame work for further development and support for new data sources and visualization methods such as seismic data, geomechanics, CSEM and others. The interface is adapted for efficient interpretation of reservoir simulation data with specialized visualizations of reservoir properties, fault arrangements fluid distribution in the reservoir and wells.

ResInsight can exploits multi-core CPUs and GPUs. Powerfull and flexible result manipulation and computations are enabled by integrating the system with GNU Octave. Achieved results can be handled and visualized further when returned to ResInsight.

The main input data for ResInsight are GRID and EGRID files together with their INIT and restart files XNNN and UNRST. Selected parts of Eclipse input files are supported by ResInsight which can help to read grid information and equivalent cell property data sets (Magnesj, 2017).

In this work ResInsight has been used to visualize the reservoir model by taking the required input files (GRID and EGRID) from Eclipse and run them in the system in which it helps to view the reservoir rock and fluid properties, wells placement for the base case and choose the right areas for new well placement.

To visualize and process reservoir models Statoil ASA, Ceetron Solutions AS and Ceetron AS have been working together as co-developer of the Reslnsight software. Reslnsight uses Statoil library to access Eclipse result files. (Magnesj, 2017).

4.3 Reservoir Rock and Fluid Properties Description from the Model.

Using ResInsight simulation some of the necessary reservoir fluids and rock properties were described to understand the field in detail. Below are some of the properties as viewed from the ResInsight software.

4.3.1 Oil Saturation Distribution.

Saturation as one of the important fluid properties in the whole process of well placement. It is necessary to understand how the fluid (oil &water) are distributed in the formation before placing (drilling) the well. Figure 28 was extracted from ResInsight software as seen the oil saturation varies from 0.0 (almost water) to 0.7005 maximum oil saturation represented by red colour see figure 28. This can help to understand where the production wells may be placed.

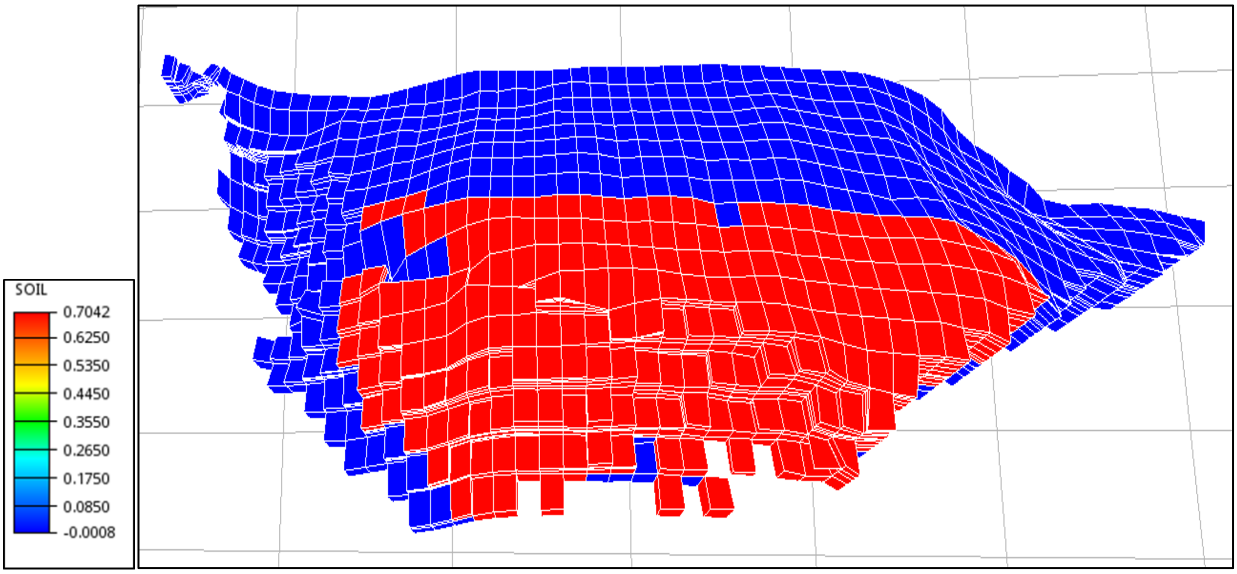


Figure 28:Oil saturation distribution

🟥 Oil

🟦 Water

4.3.2 Porosity and Net to Gross-NTG

Porosity represent the fraction of pore spaces occupied by the reservoir, this helps to determine how much hydrocarbon can be stored in the reservoir. As indicated in figure 29 porosity in Statfjord I-1 segment varies from 0.17 up to 0.31 with an average of 0. 27 or 27% which is a good porosity to produce the reservoir fluid. Net to gross defines the potential of the reservoir pay. As indicated in figure 30 the NTG varies from 0 (minimum) up to 0.9997 maximum.

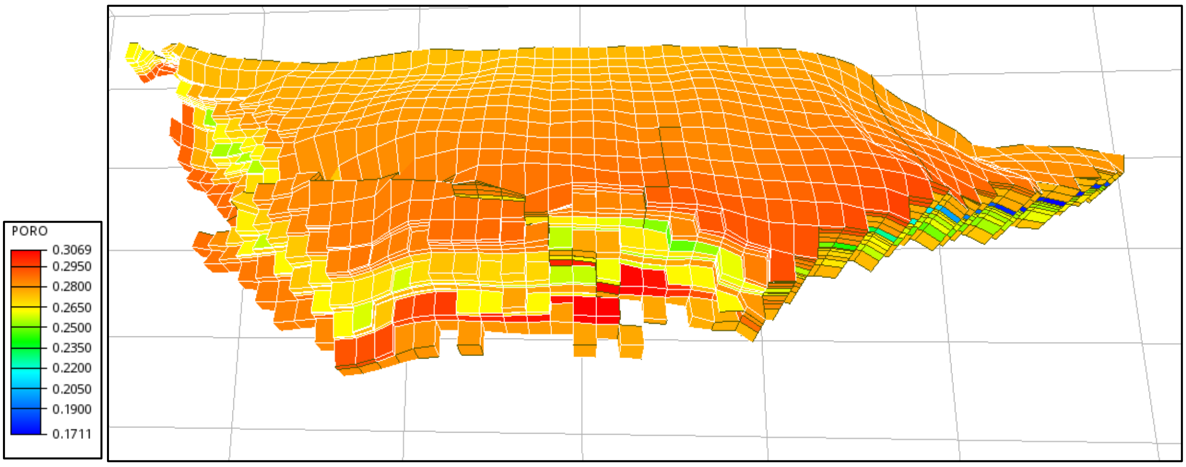


Figure 29:Porosity distribution in the reservoir model

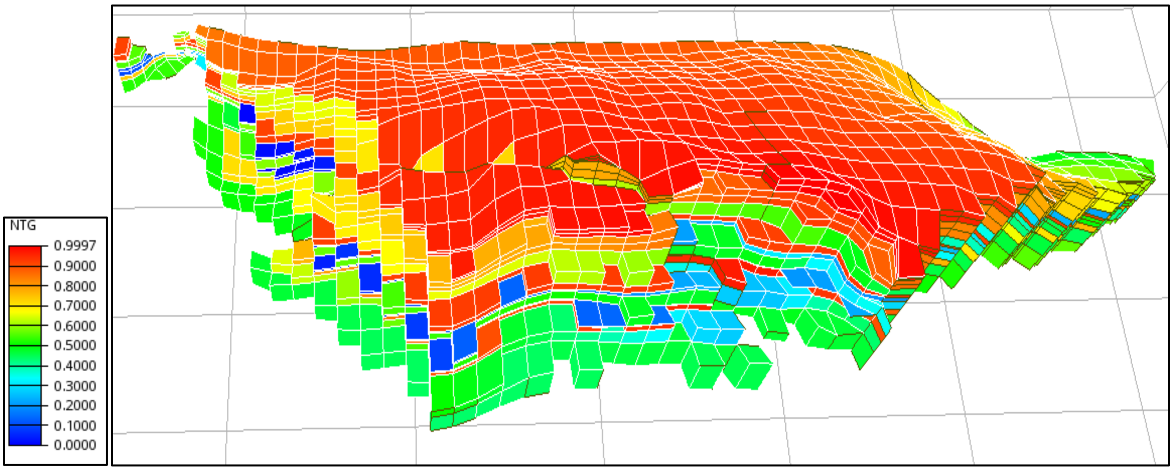


Figure 30: Net to Gross description

4.3.3 Reservoir Pressure Distribution.

Reservoir pressure distribution indicate how the reservoir can be produced also it helps to plan which recovery methods may be applied and when should it start. From figure 31 the reservoir pressure of Statfjord I-1 segment varies from 232.6 bars to 443.3 bars. But it can be observed that the pressure distributions for the reservoir lie between 310 up to 335. The initial reservoir pressure described in table 3 as 318 bars which is within the range.

The ability of the well to produce depend mostly on the strength of the reservoir pressure, thus, it is important to study the pressure behavior of the formation before starting production. This will help to plan for future strategies such as waterflooding, gas injection and other recovery techniques and how they will be implemented.

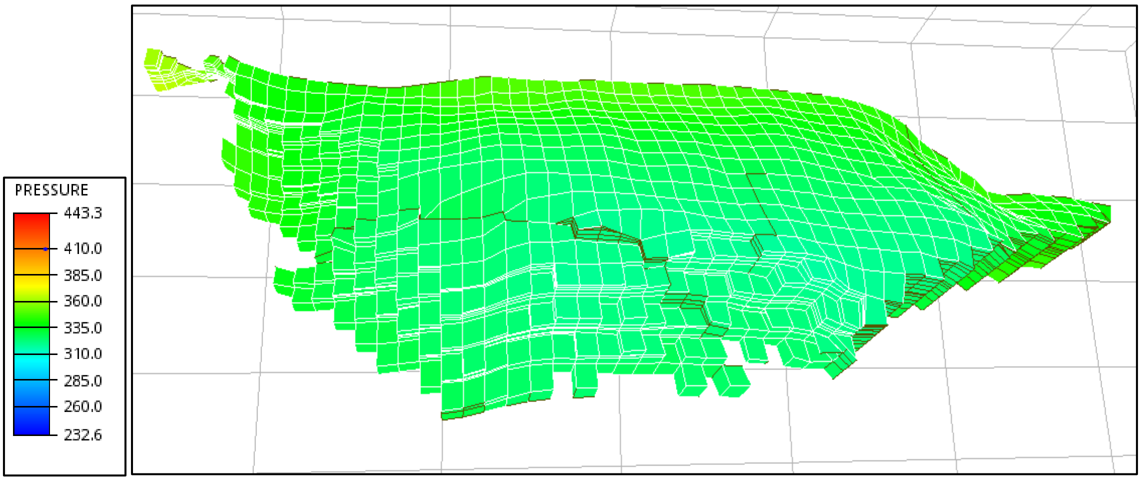


Figure 31: Reservoir pressure distribution

4.3.4 Permeabilities (PERMX & PERMY) & PERMZ).

Permeability indicates the ability of the reservoir to transmit the fluid from the one place to another. It is an important reservoir property to be understood before deciding for the well placement procedures. As indicated from figure 32, the permeability distribution in x and y direction are the same varying from 44mD to 4354 mD with an average of 872.45mD. On another side the permeability in z- direction is low compare to that in x and y as it varies between 13mD to 1306mD with an average permeability of 261.71mD.

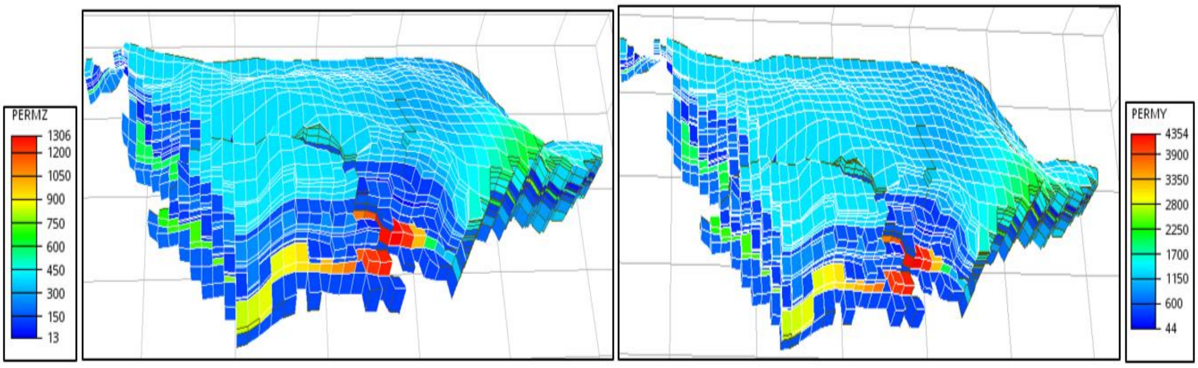


Figure 32:Permeability distribution in X,Y and Z

4.3.5 Faults Arrangement.

Statfjord I1 segment is characterized by a lot of faults which can affect the well placement activity. As shown from figure 34 the potential area with oil accumulation may greatly be affected by the two faults which are 1s-34f1 and FC-16S, and the injection process can be affected by the remaining faults which are 6e-34f1, I1-NORTH and 12E-34F1.

Before selecting the place to drill the well it is very important to get familiar with the fault arrangement in the segment. Thus, using eclipse and Reslnsight software the simulation model was used to study the faults arrangement of the Statfjord formation as seen in figure 33.

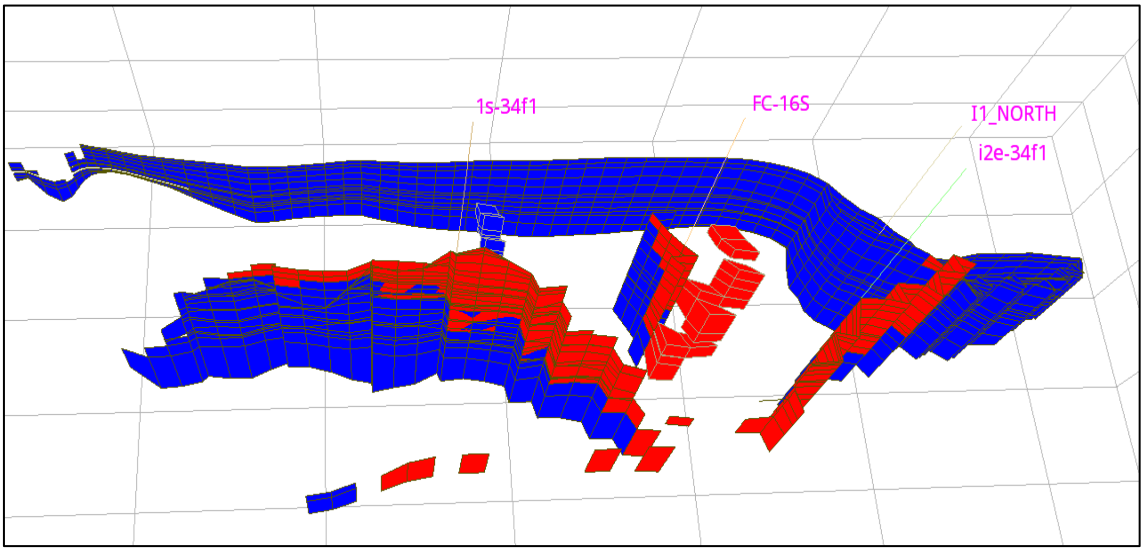


Figure 33: Description of faults arrangement

4.4. Overview of the Base Case.

The simulation of Statfjord I-1 segment in Gullfaks field started from May 1992 and ends at January 2001. The base case comprises of three wells of which two are production wells named as A-36 and C-16 and injector well named A-41as described in figure 34 and figure 35. From May 1992 to 1994 the production mechanisms were based on natural drive, but the reservoir pressure was decreasing very fast thus, to maintain the production from 1994 water injection was applied to provide pressure support to the reservoir aquifer. Thus, the base case is the simulation model with continue water injection up to date. As explained above the final management report has described that the oil recovery up to 2015 was 56% but the expected recoverable reserve up to the end of the field is about 68% of total reserve.

It was not possible to apply any chemical injection method to the base case since chemical injection such as polymer and surfactant injection can be applied when maximum oil production by waterflooding has been attained. Figure 36 describes the recovery factors for the base case (history match and forecasted (extended) case).

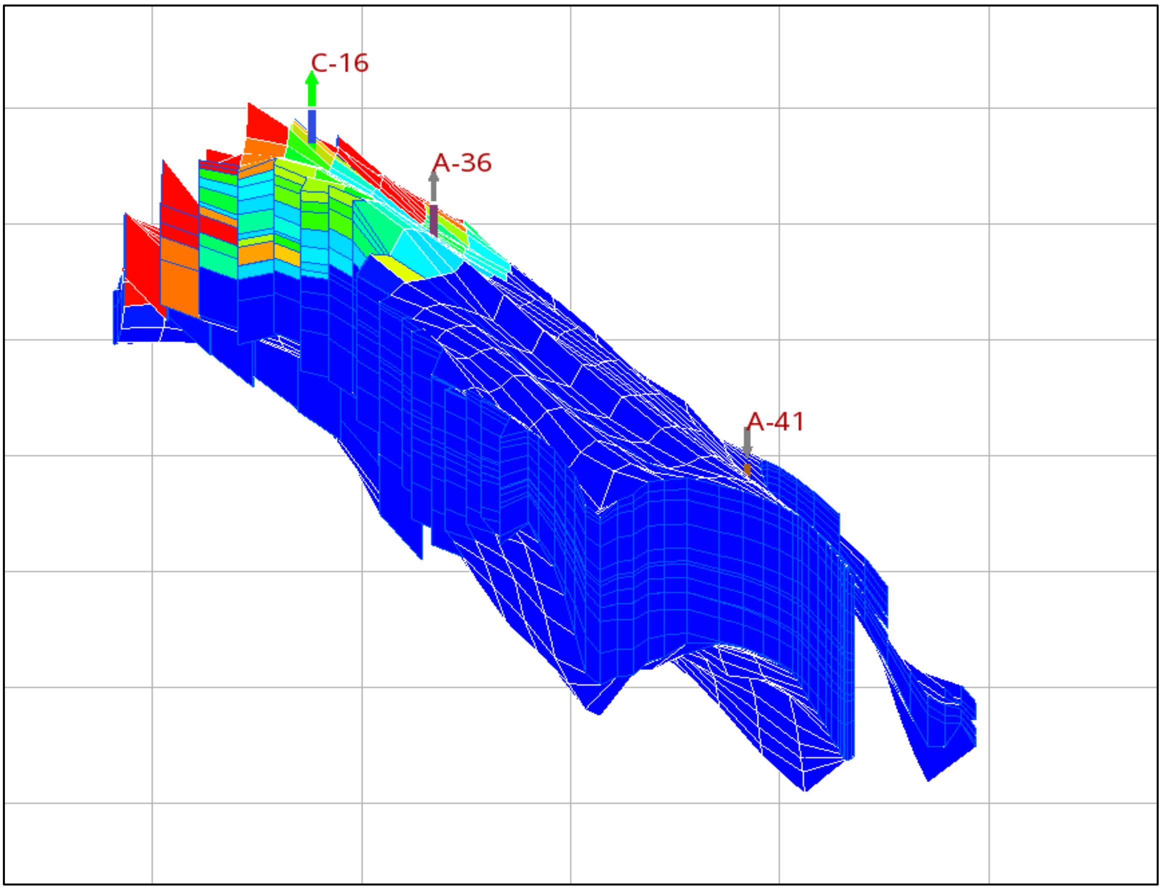


Figure 34:Description of the base case viewed from ResInsight.

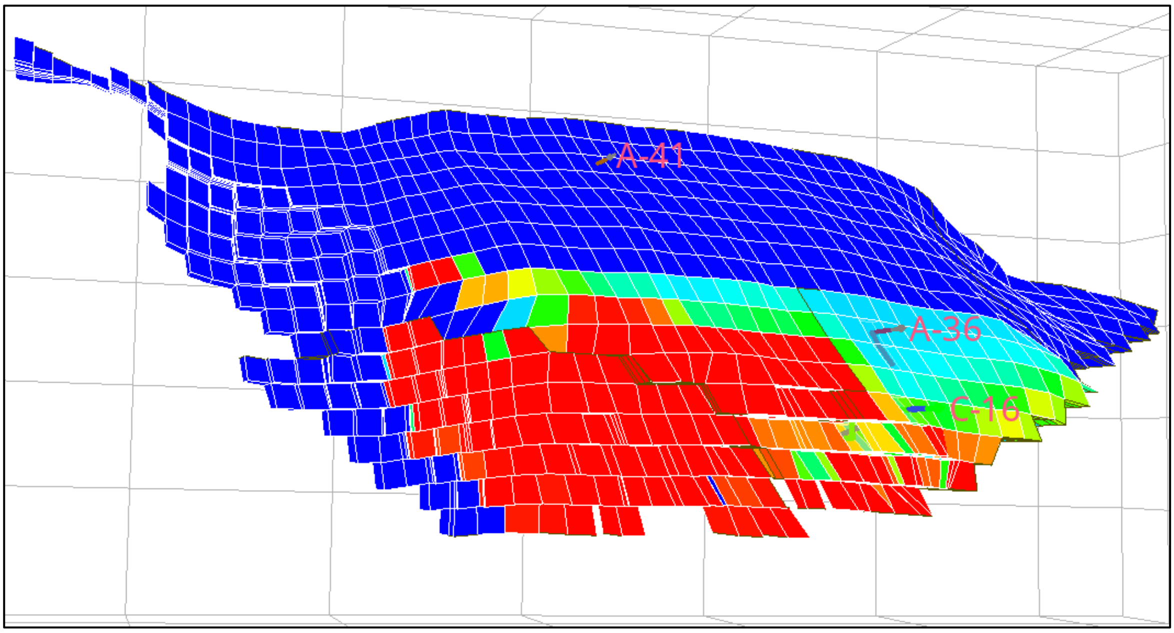


Figure 35:Well arrangement as viewed from the simulation model of the base case.

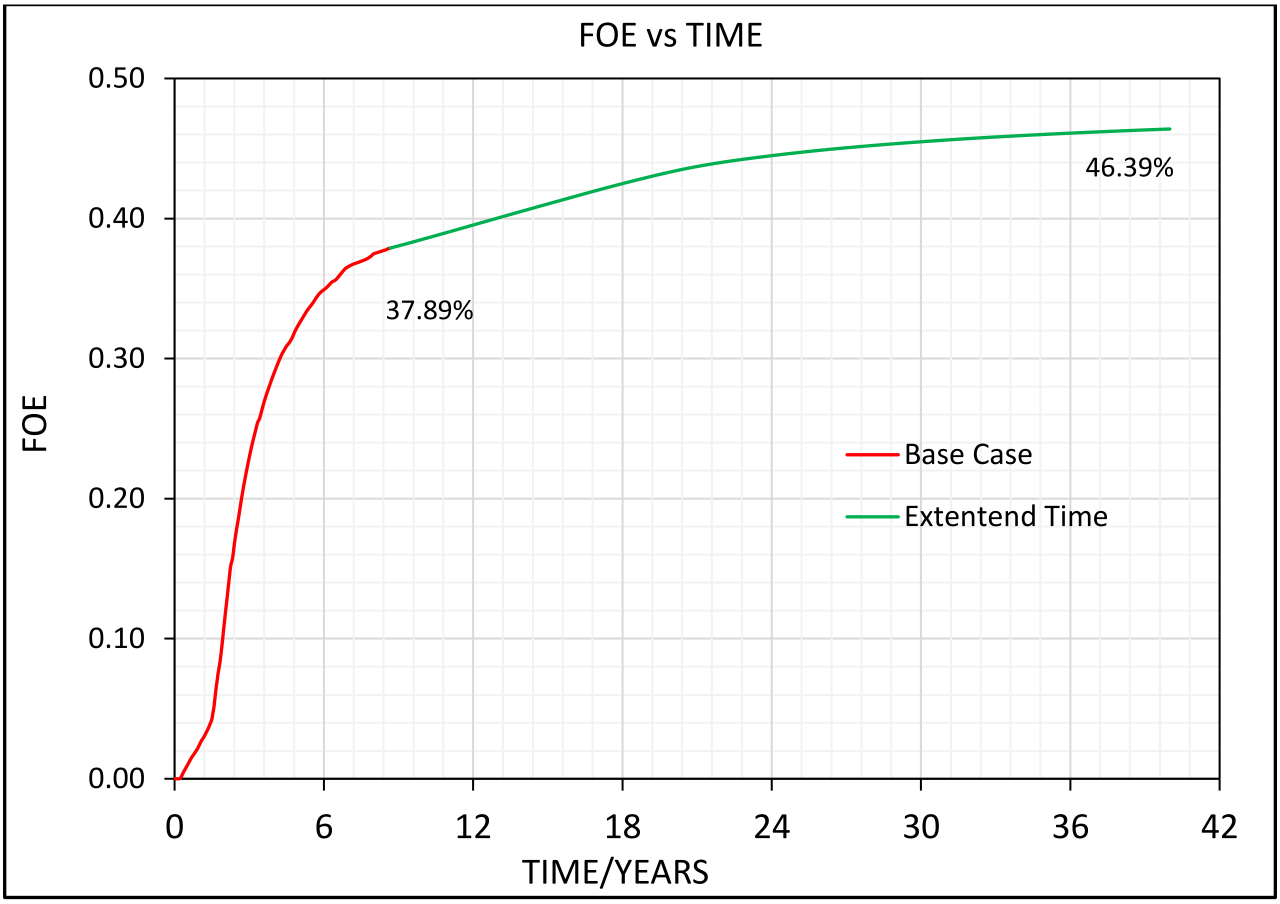


Figure 36:Oil recovery factor for the base case (history and extended cases).

CHAPTER 5

5.1 Description of the Proposed Case .

Based on the well placement in the base case, the recoverable oil was about 46.39% only and no more oil production could be attained as indicated in figure 36 above. But still there is a lot of oil remained behind unproduced this can be resulted from improper well placement and faults arrangement in the reservoir system.

There was a need to propose a new case with additional of two wells (one producer and one injector) so that the whole field can be produced. The proposed case comprises of five wells with three production wells and two injection wells as indicated in figure 37. It is important to consider the reservoir heterogeneity (faults arrangement, reservoir properties and fluid distributions) when selecting the best part of the reservoir for well placement. Chemical injection such as polymer or surfactant flooding are applied when the reservoir can no longer be produced by waterflooding. While low salinity water is applied either as secondary or as tertiary method.

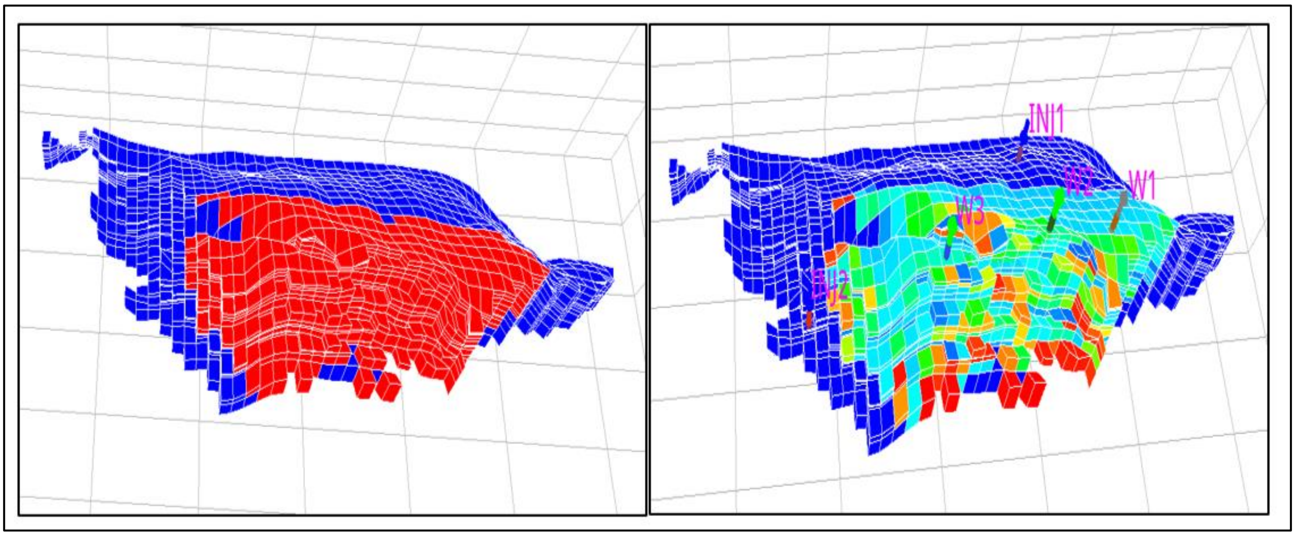


Figure 37:Oil distribution before and after production for the proposed case.

Figure 38 presents the recovery factor for the base case and the new case (proposed case). As indicated from the figure it can be observed that the new case with three production wells and two injectors attained a recovery factor of 63.65% which have been improved enough compare to the base case with a recovery factor of 46.29%. This simulation period ended up in 2030 for the two cases.

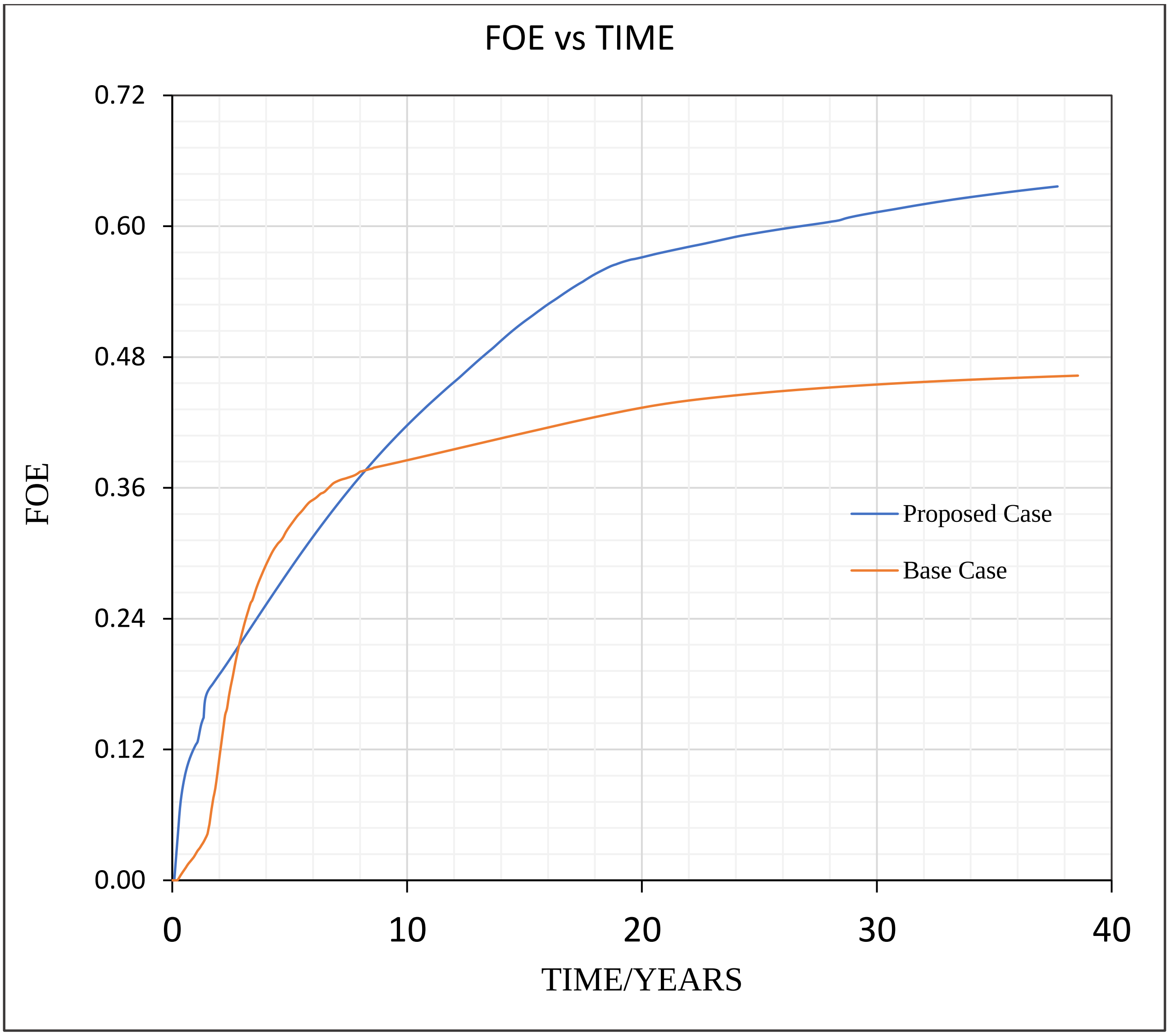


Figure 38: Oil recovery for base case and proposed (new) case.

5.2 Simulation Works and Results.

The main purpose of the simulation work is to evaluate the efficiency of the chemical injection (polymer, surfactant and low salinity water) to maximize the volume of oil production base on the volume of chemical injected. Four cases including proposed case with waterflooding, surfactant flooding, polymer injection and low salinity water flooding will be discussed, and comparison of their results will be presented to obtain the most effective IOR method that can improve economically the oil recovery for Statfjord I-1 segment in the Gullfaks field. In addition, a simple economic analysis based on the incremental oil produced will be performed for all cases in order to select the most economical viable IOR for the field.

5.2.1 Case 1: Proposed case with Waterflooding

New case was proposed so that the reservoir could be produced to the irreducible oil saturation by waterflooding then the application of chemical injection by polymer and surfactant flooding can be applied. The proposed case comprises of five wells of which three are producers and two injectors as indicated in figure 37.

Simulation was achieved and the important parameters such as field oil efficiency(FOE), field oil production total(FOPT), total field gas production (FGPT), field water cut, field oil initially in place and total field water production and injected were obtained and presented in excel sheets see the attached files.

The maximum water cut was set as 95% for the first case which attained recovery factor of 65.58% with total oil production of 967MSCM. Then the water cut was set to be 97% for second case which achieved a recovery factor of 67.96% with total oil production of 1.18BSCM and produce the field for about 10 years more. After simulation of the new case the results were plotted for the two case and compared as seen in figure 39.

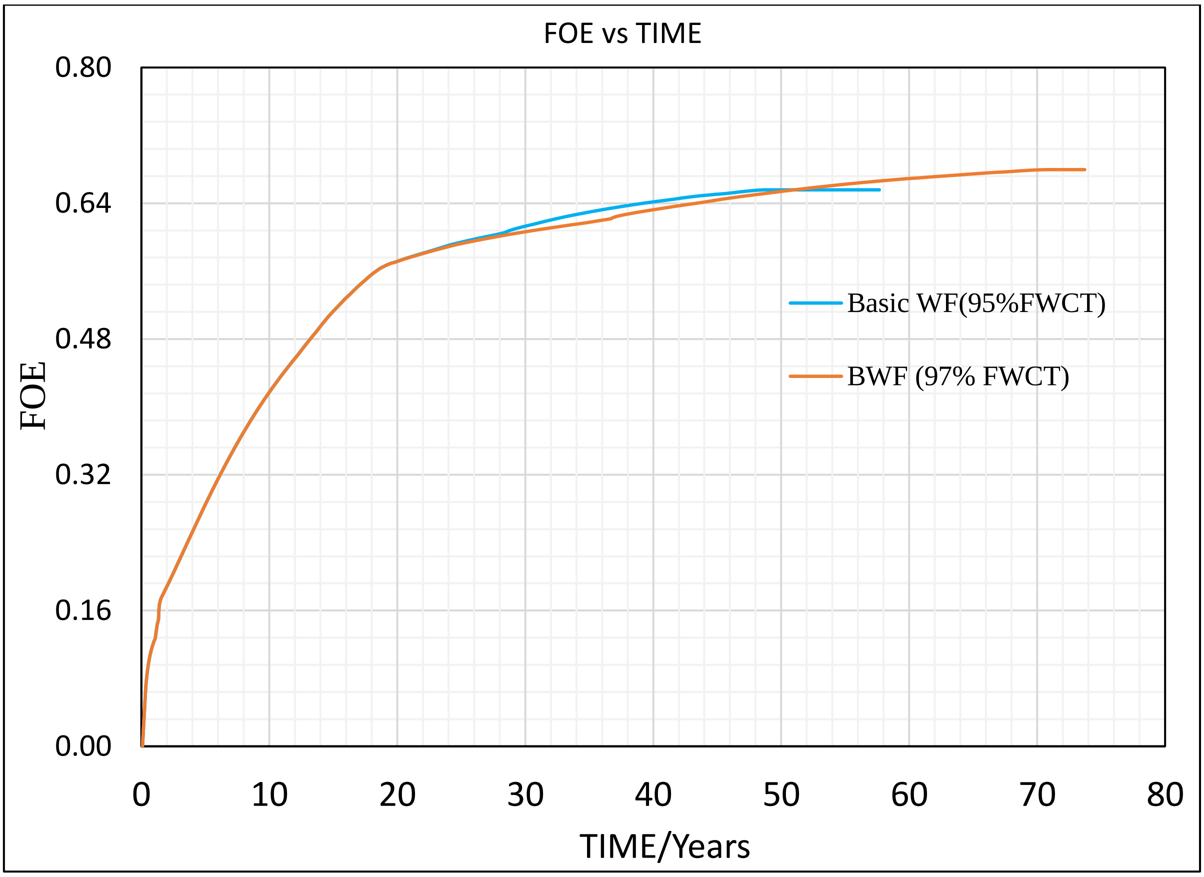


Figure 39: Oil recovery factor for FWCT of 95% and 97%.

5.2.2 Case 2: Surfactant Flooding Simulation Results.

Chemical injection process must involve a detailed laboratory experiments before applied to the real field since these chemicals are very expensive and complicated. Thus, it is pertinent to insure there will be no wastage of the chemical into the field without any success. Apart from laboratory experiment as a small-scale test, it is better to test the injection process using various software to see the effect of the chemical before taking it to the field. In this case surfactant with various concentration were tested into the eclipse model.

Using the proposed case, the water flooding was injected up to 2035 then followed by continuous surfactant injection for two years and then waterflooding for about ten (13 years). The main function of injected surfactant is to reduce interfacial tension between the oil and water. Various concentrations were injected from 2.5kg/m3, 5kg/m3, 10kg/m3, 15kg/m3 and 20kg/m3. From table it can be clearly seen that the application of surfactant injection into the reservoir cannot be economical viable. As a result, the discussion concerning surfactant was ended up and look forward for the remaining chemical methods. Figure 40 and table 4 represent the result for surfactant flooding.

Table 4: Summary for incremental oil recovery, oil and gas production for surfactant flooding.

CASES	FOE (%)	FOPT	FGPT	% increasse	incremental	incremental
		scm	scm	in recovery	oil produced	gas produced
BWF	66.63	6.69E+06	5.70E+08	0	0	0
2.5 kg/m3	66.83	6.71E+06	5.714E+08	0.2	12997	1620350
5 kg/m3	66.8	6.70E+06	5.710E+08	0.17	10115	1210690
10 kg/m3	66.78	6.70E+06	5.707E+08	0.15	7979	904960
15 kg/m3	66.74	6.70E+06	5.702E+08	0.11	4208	438910
20 kg/m3	66.72	6.69E+06	5.699E+08	0.09	1681	121090

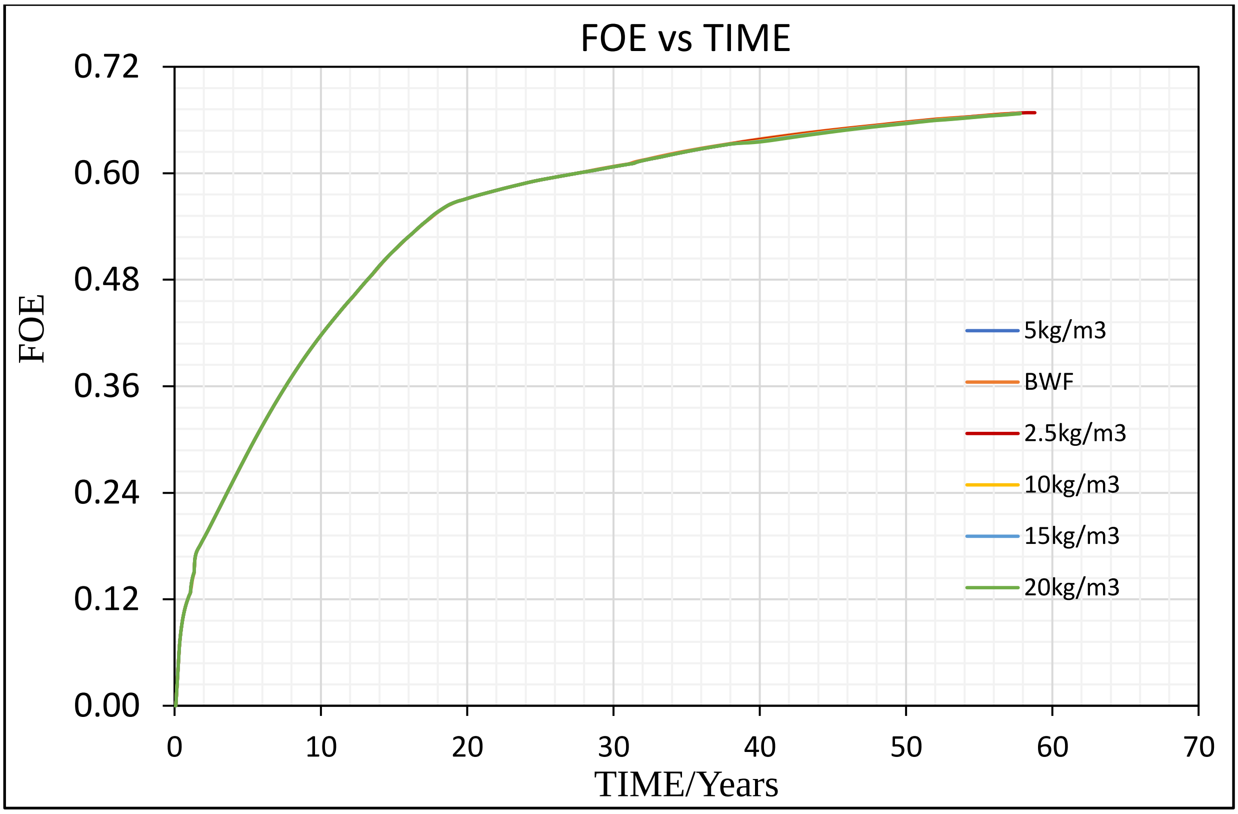


Figure 40:Oil recovery factor for various surfactant concentrations.

5.2.3 Case 3: Polymer Flooding Simulation Results.

Polymer flooding is another chemical IOR method that can produce a significant increase in the oil recovery compares to normal water flooding. Polymer increases the viscosity of injected water consequently improves the volumetric sweep efficiency. As the water viscosity is increased, mobility ratio become lower as a results viscous fingering effect is reduced, and more oil is contacted in large scale. In the polymer flooding various concentration were introduced to evaluate the effect on the field oil efficiency and field oil production.

The following concentrations from 0.3kg/m^3 0.5kg/m^3, 0.75kg/m^3,1.0kg/m^3 and 5kg/m^3 were applied into the model and the effects were analysed.

Even though very small effect was observed for all four concentrations as seen in figure 41. It was observed that when polymer concentration increased the recovery effect become even less than that obtained by conventional waterflooding as indicated

Generally, it can be discovered that the system does not support the chemical injection for the two chemicals (polymer & surfactant) when compared to low salinity water flooding which provided significantly an improve in oil recovery as it can be describe below. From then the simulation works focused on low salinity water flooding which shows some improvement in the oil recovery when compared to conventional waterflooding.(ie polymer and surfactant injections were not discussed any more in this work.

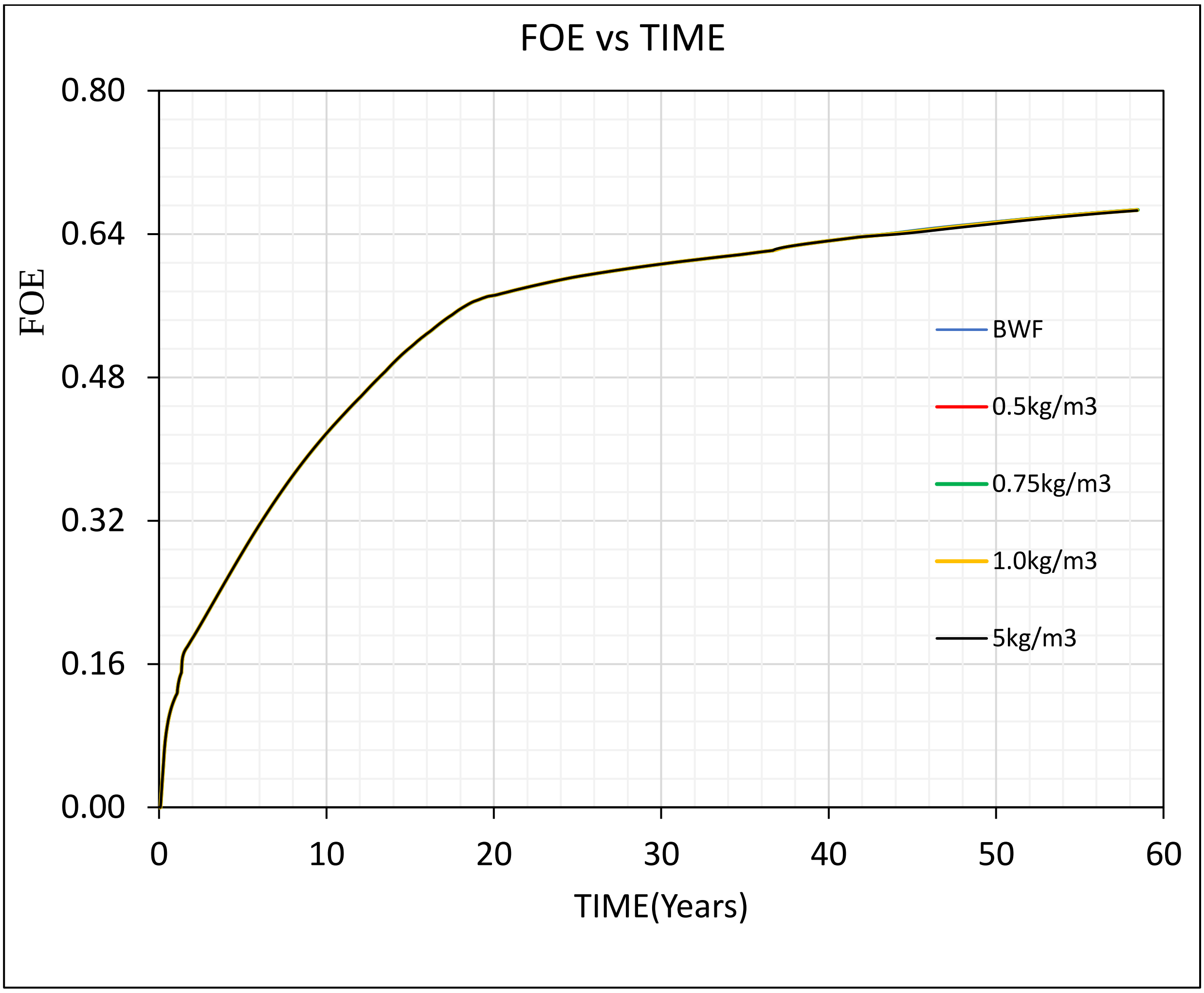


Figure 41: oil recovery factors for polymer cases

Table 5: Summary for improved oil recovery, oil production and total gas production by polymer injection.

Chemical	Scenario	FOE	FOE	FOPT	FGPT	Incremental oil	Incremental Gas
		%	Incremental	(SM3)	(SM3)	(SM3)	(SM3)
	BWF	66.63	0.000	6.69E+06	5.62E+08	0	0
Polymer conc.	0.50	66.70	0.075	6.69E+06	5.63E+08	7564	791100
Polymer conc.	0.75	66.69	0.061	6.69E+06	5.63E+08	6074	663490
Polymer conc.	1.00	66.67	0.042	6.69E+06	5.63E+08	4264	521660
Polymer conc.	5.00	66.62	-0.005	6.68E+06	5.62E+08	-497	32570

5.2.4 Case 4:Low Salinity Waterflooding Simulation Results.

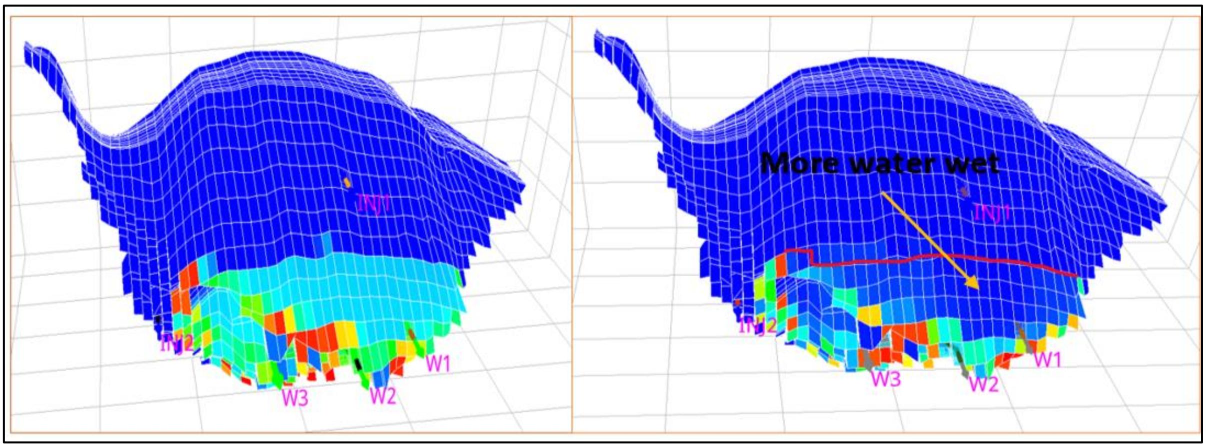
Low salinity waterflooding is one of the improved oil recovery technique which has recently received much attention. Significant improve in oil recovery by water injection with low salinity has been indicated through laboratory and field tests. It has been discovered that brine compositions, fluid and rock properties and the extent of dilution are the most sensitive parameters to the process.

From management report some of the laboratory experiments performed on various cores from Gullfaks are extremely promising (Talukdar & Instefjord, 2008).

The main objective of injecting water with low salt concentration is to alter the wettability of the system to become more water wet, thus increase the sweep efficiency significantly when the system is more water wet.

Figure 42 and figure 43 describe the change in wettability of the system in which case the system seems to be more water wet when LSW is injected compare to the convectional water injection. The system behaves like a piston displacement when injecting 500ppm and 1000ppm as described in figure 51. Even though the water breakthrough early for the 500ppm compare to 1000ppm and others. Thus, the higher the salt concentration in the injection water the late the water breakthrough and vice versa.

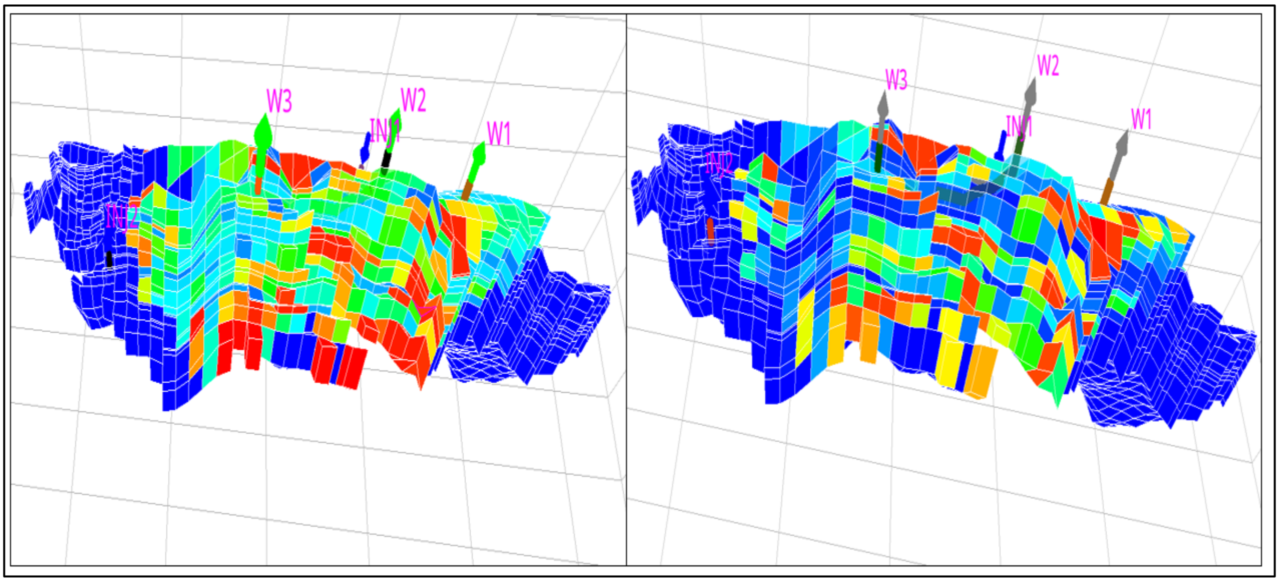
In this work low salinity waterflooding has been applied as secondary and tertiary techniques in which for all scenario various salt concentrations were used to see the effect on the field oil efficiency (recovery factor), total field oil production and total field gas production.



Basic Waterflooding effect

Low salt effect (more water wet system)

Figure 42: Wettability change resulted from injection of low salinity water



Basic Waterflooding effect

Low salinity waterflooding effect (more wet)

Figure 43:Description of Basic water flooding and low salinity water flooding

5.2.4.1 Low Salinity as Secondary Method.

In this scenario the injection process started from the beginning as what is applied to conventional waterflooding. Firstly, it was applied to the base case which started from May 1992 and end up at January 2001the results showed some improvement on the recovery factor from 37.89% for convectional water to about 40.1% for low salt water as indicated in figure 44.

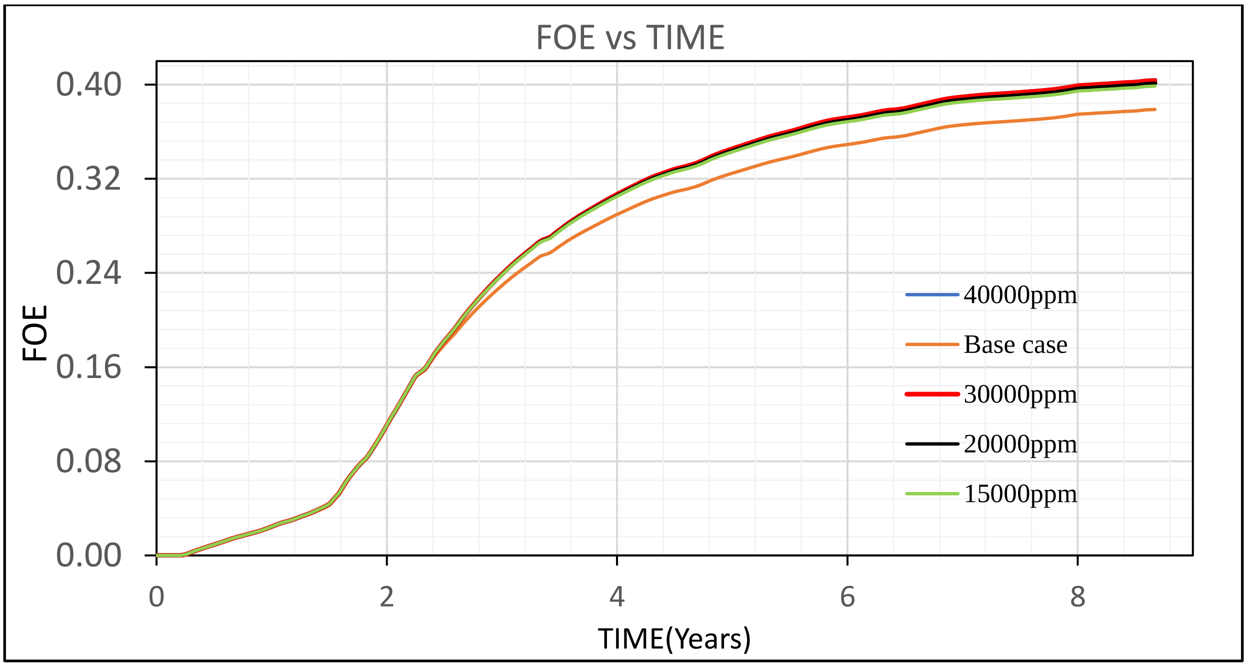


Figure 44:Description of the effect of salt concentration to the oil recovery factor for the base case

The proposed (new) case with two injection wells and three production wells provide a very clear effect of the low salinity compared to conventional waterflooding as described in figure 43. Figure 42 describe the wettability effect in which the system become more water wet with low salinity water flooding compare to normal water flooding. As secondary drive mechanism, a number of concentrations were tested from 500ppm, 1000ppm, 2500ppm, 3000ppm 5000ppm, 10000ppm and 20000ppm.

There is significantly an improve in oil recovery when low salinity water was injected into the system as described in figure 45& 46. From these observations it is clear that system support the application of low salinity waterflooding compare to surfactant and polymer flooding since the system is a water wet system.

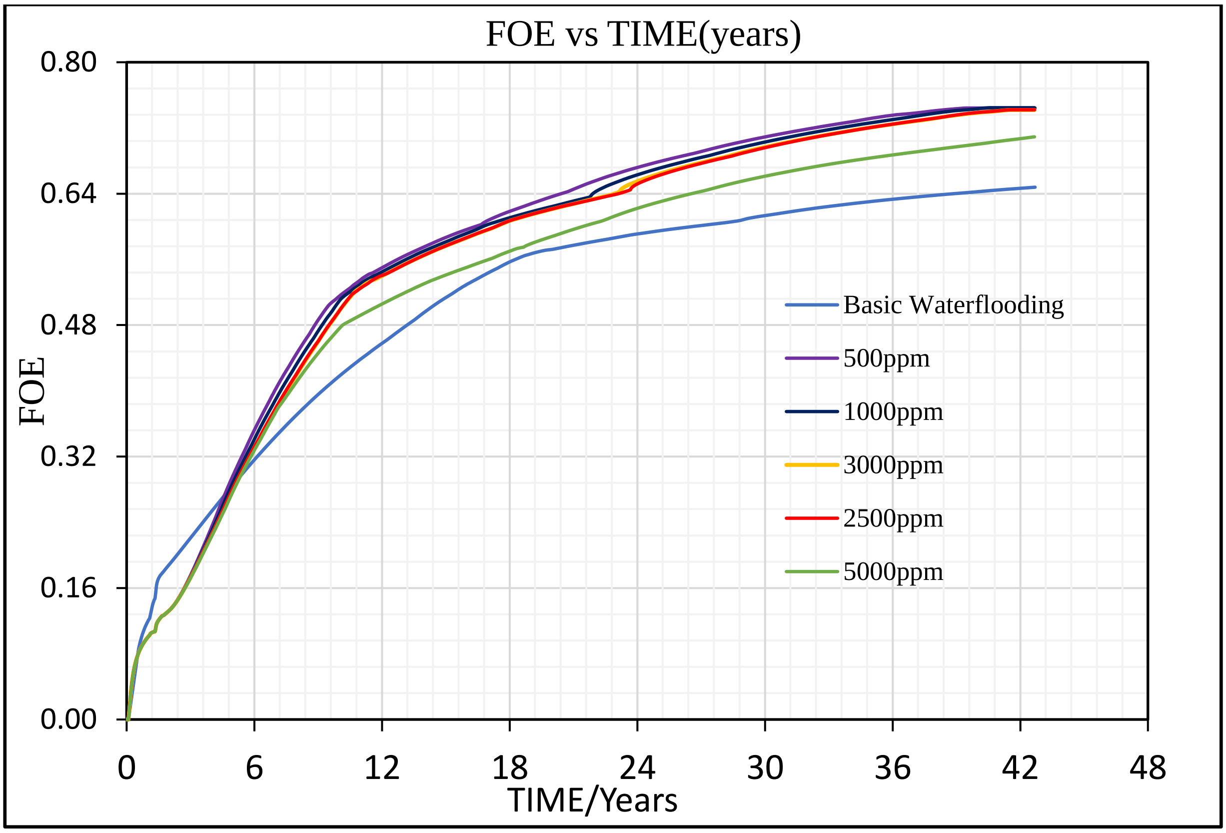


Figure 45: Oil recovery for lower salt concentrations (500ppm,1000ppm,2500ppm,3000ppm &5000ppm).

For the higher salt concentrations described in figure 47 the simulation period was extended up to 2050 as a result of late breakthrough. Although the simulation period is longer compared to the one with lower salt concentrations as observed in figure 45, the improve in oil recovery is almost the same to the one achieved by injecting water with salt concentrations of 1000ppm.

The advantage obtained by injecting lower salt concentration is to attain maximum oil recovery for short period which may help to avoid increase in operating costs.

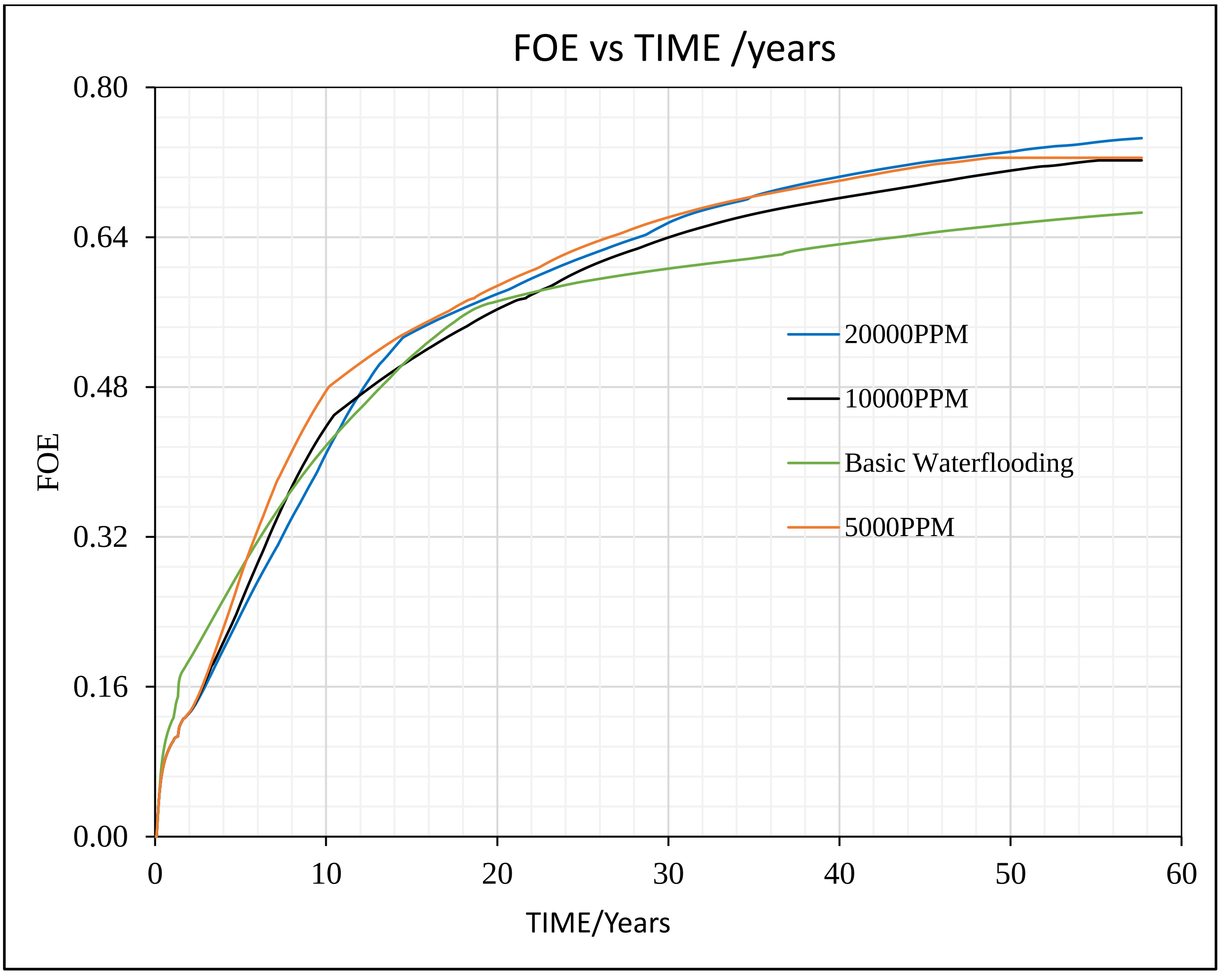


Figure 46: Field oil recovery for salt concentrations of 5000ppm, 10000ppm and 20000ppm

Consequently, there is dramatic increase in total field oil and gas production by injecting low salinity water into the reservoir. Figure 47 and figure 48 describe the effect of low salt water into the total oil and gas produced respectively.

Figure 49 and figure 50 represent the total field water produced and injected respectively. From the figures it can be observed that injecting water with very low salt concentration results in huge amount of water production. The amount of water injected also is higher for lower salt compared to higher salt water.

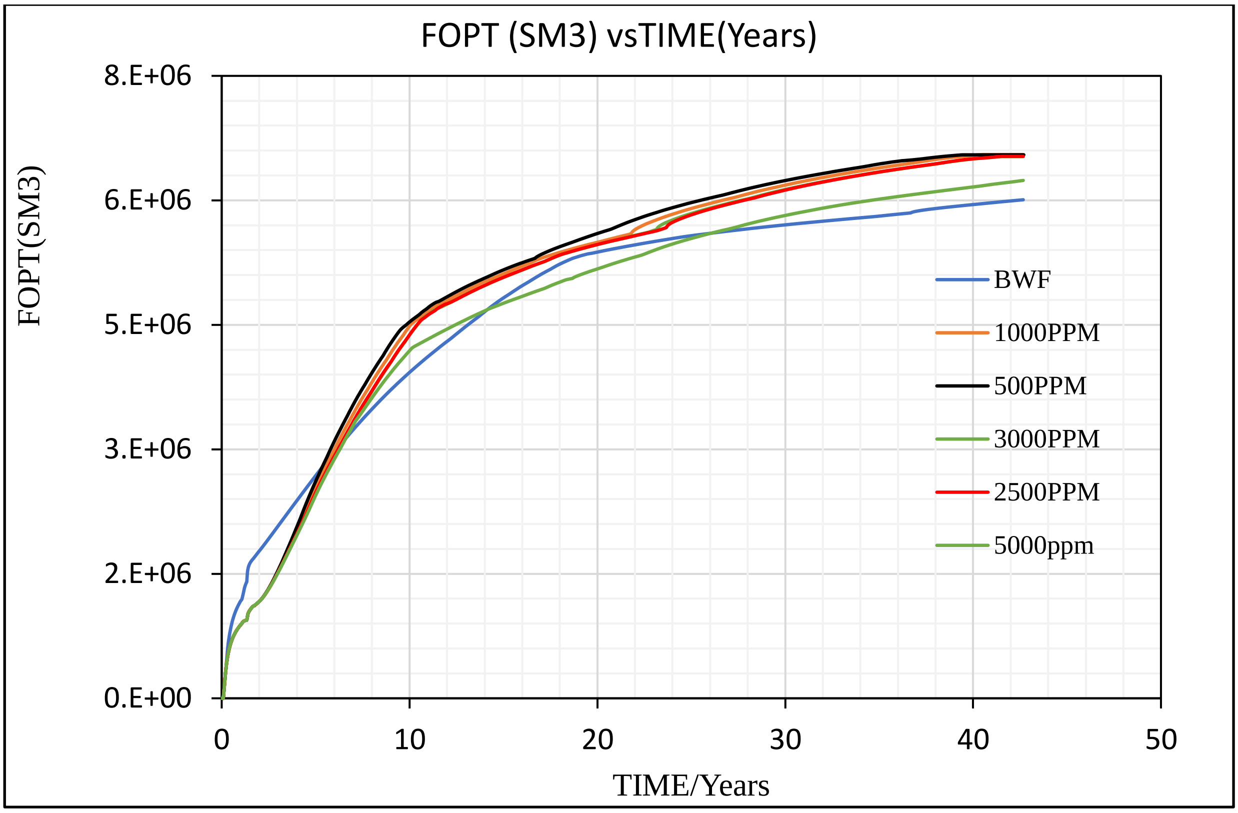


Figure 47:Description of total oil produced for each salt concentration.

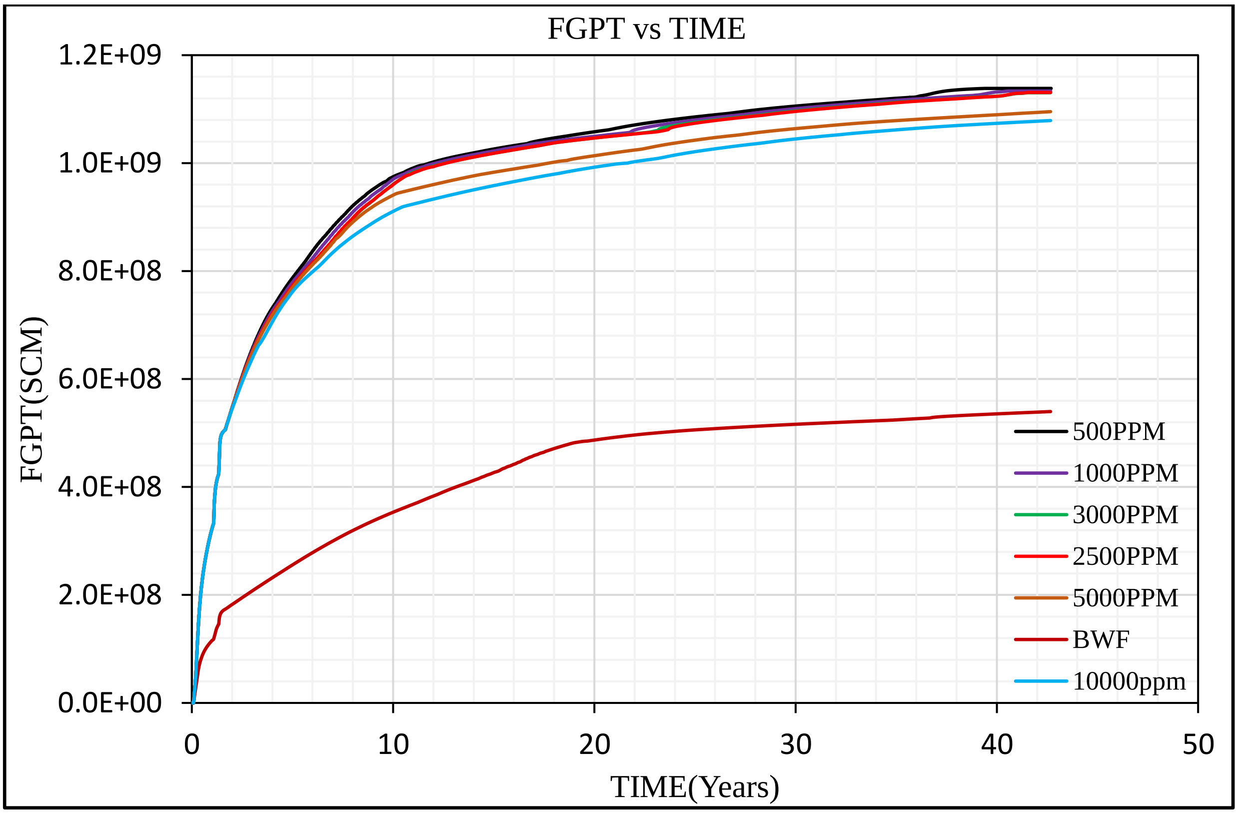


Figure 48:Total gas production for various salt concentrations compared to basic water

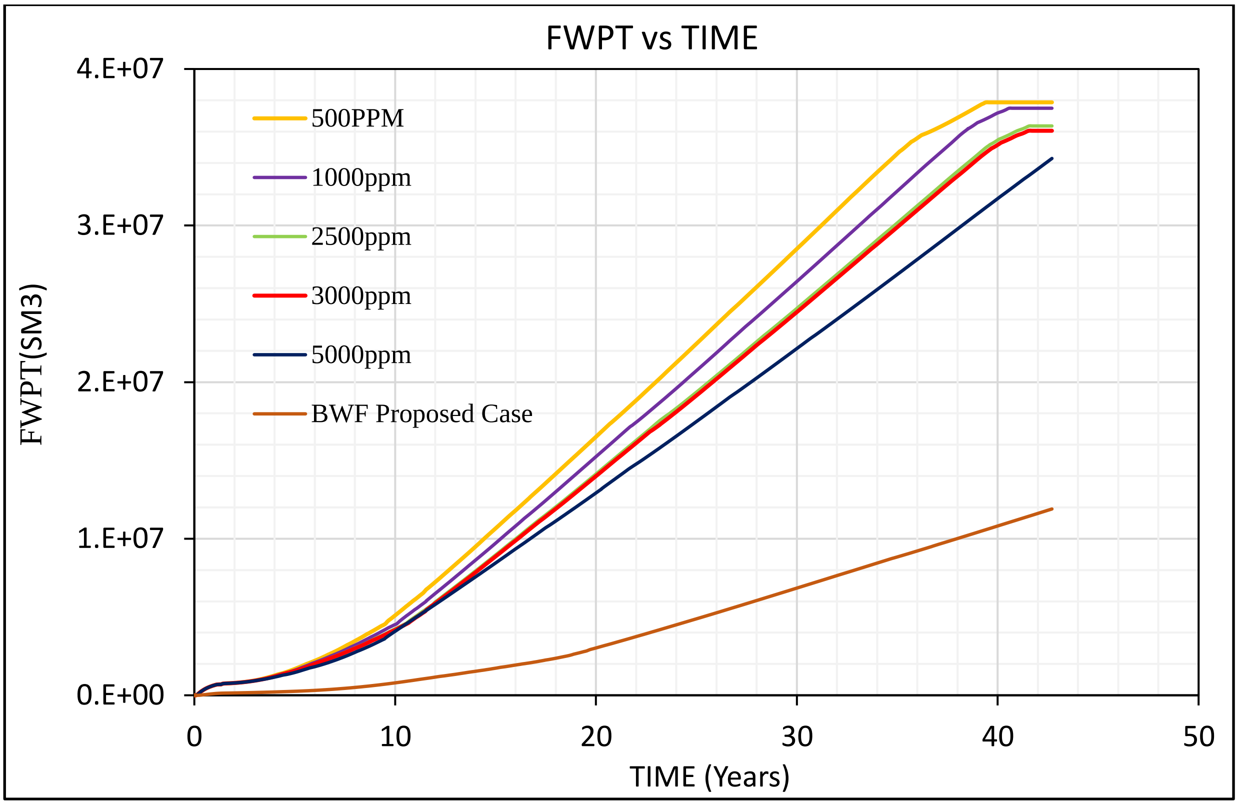


Figure 49: Field water production for LSWF as secondary case.

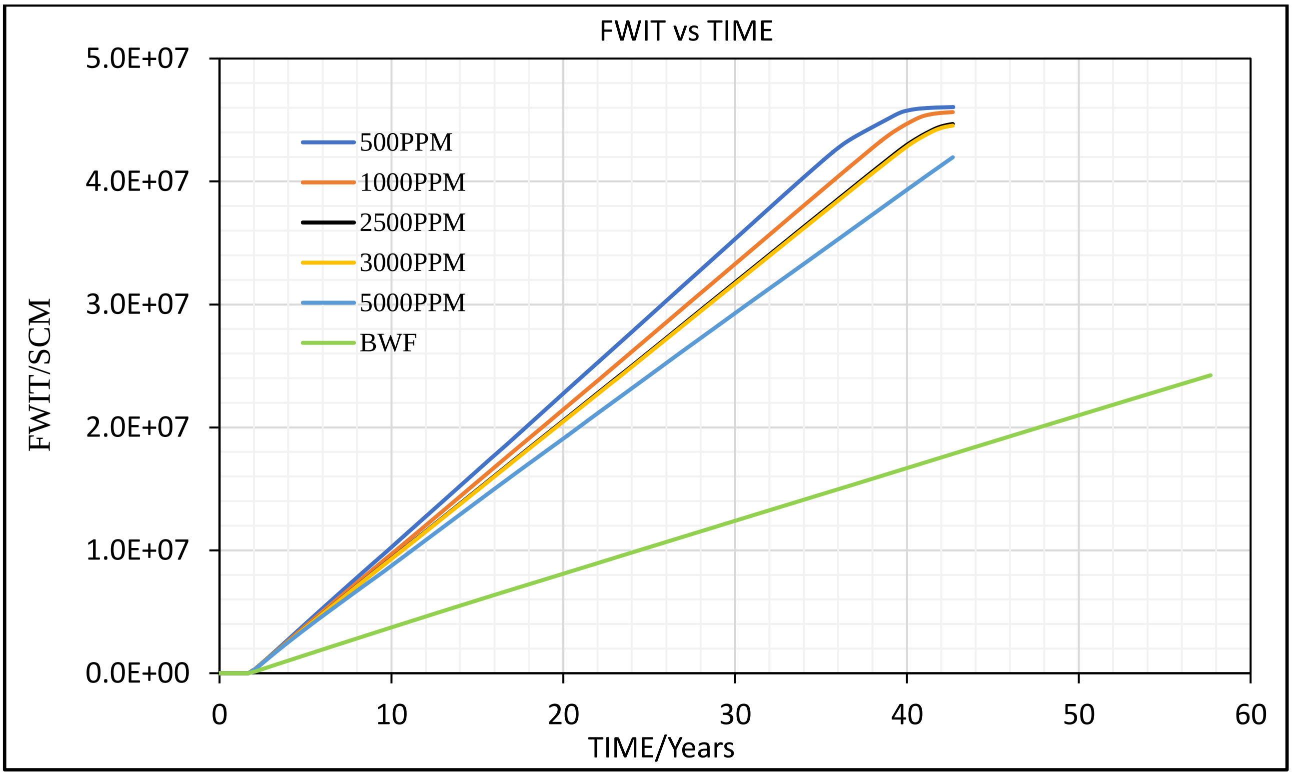


Figure 50: Description of Total field water injection for various salt concentrations

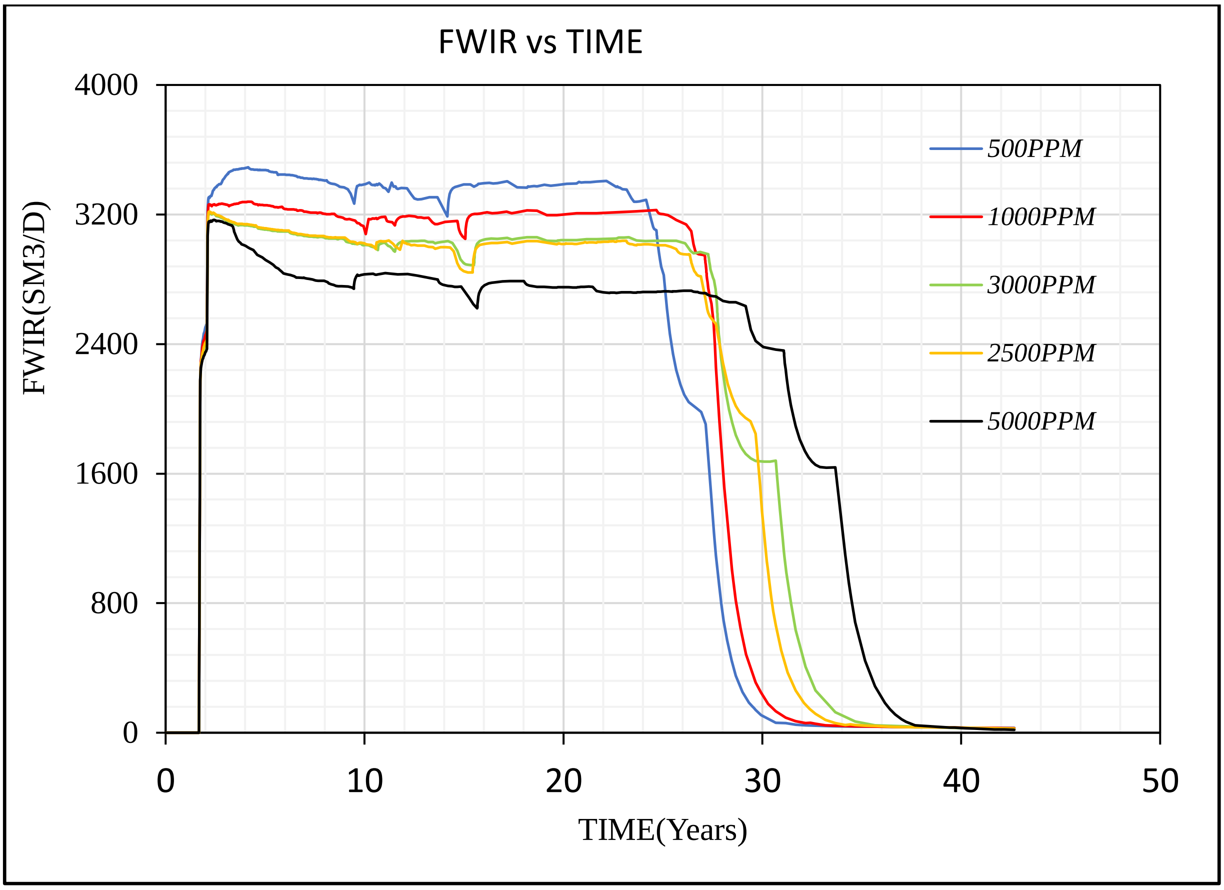


Figure 51: Description of the efficiency of field water injection rate.

From figure 51 it can be observed that the lower the salt concentration the earlier the water break through. This indicate that when injecting water with very low salt concentration the amount of water injected is very huge as a result early water break through occurs.

5.2.4.2 Low salinity as tertiary method.

In this scenario high salt waterflooding (HSWF) mostly the concentration of the formation water is injected first followed by low salt waterflooding. According to (Talukdar & Instefjord, 2008) the salt concentration of the Gullfaks field is about 49000ppm as indicated in table 3. In this work the high salinity water (HS) with 49000ppm was injected from May 1992 to January 2015 as high salinity waterflooding. Then various scenarios with low salt concentrations (LS) were injected. Low salinity process involved a number of concentrations from 500ppm, 1000ppm, 5000ppp, 10000ppm, and 20000ppm. Significant improve in oil recovery have been observed from all these cases as indicated in figure 52.

Figure 53 and figure 54 describe the total oil production (FOPT) and total gas production (FGPT) between high salt waterflooding (HS) case and the low salinity (LS) water injection cases. It has been observed that when injecting low salinity water, the amount of water production increases dramatically compares to the normal water flooding as discussed earlier.

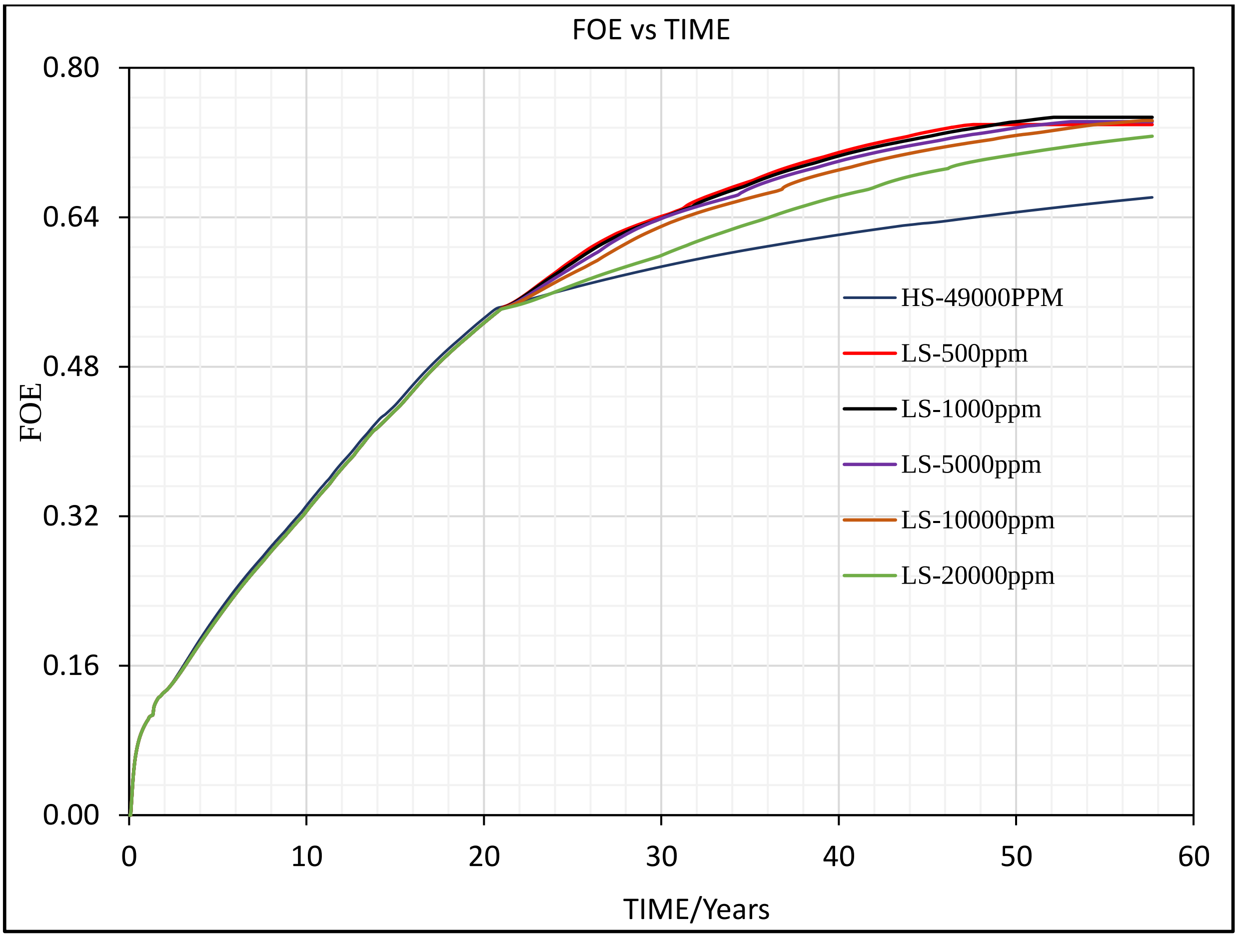


Figure 52:Oil recovery factor for various concentrations by low salinity as tertiary method.

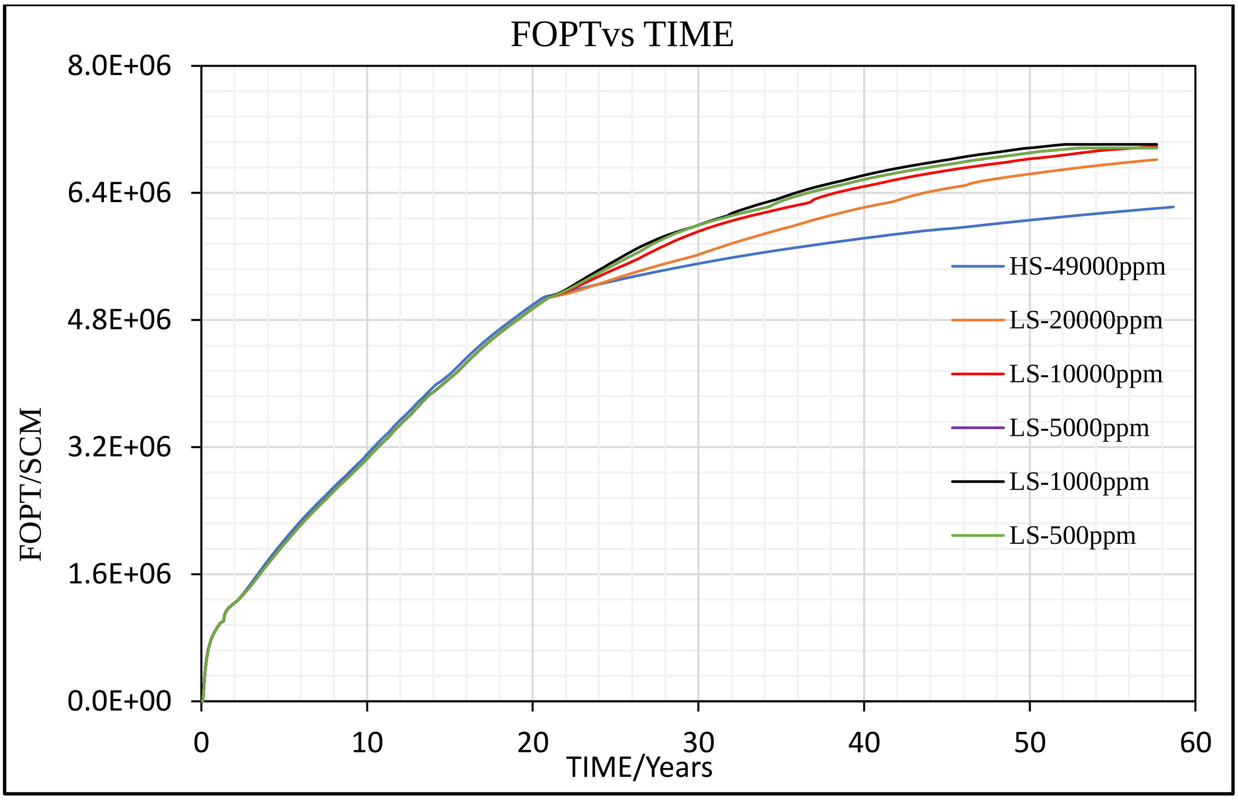


Figure 53: Description of total oil production at different salt concentration for tertiary case.

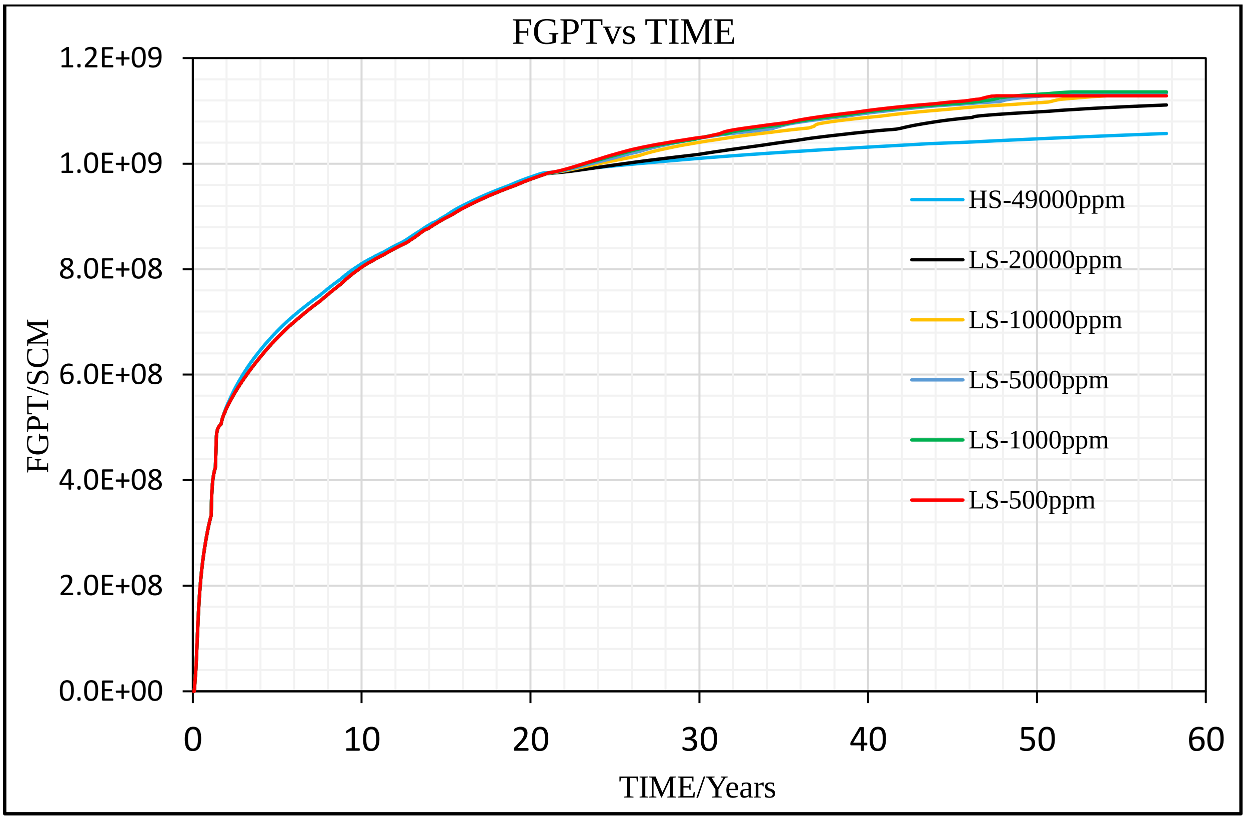


Figure 54: Total gas production when low salinity applied as tertiary method.

5.2.5 Comparison of all IOR Methods Implemented.

Figure 55 describes a comparison of three IOR methods implemented in the reservoir simulation model with the basic water flooding. When comparing the chemical methods implemented into the reservoir model with the simulation period up to 2035, low salinity with salt concentration of 1000ppm resulted into maximum oil recovery of 74.46% followed by the salt concentration of 500ppm which attained a field oil recovery of 74.42%.

The proposed case (new case) with conventional waterflooding attained the maximum oil recovery of about 64.79%. Polymer and surfactant injection showed no effect on the oil recovery factor the recovery factor achieved by flooding polymer or surfactant is almost the same to conventional water flooding as seen in figure 55.

Thus, when compared low salinity water with polymer, surfactant and conventional waterflooding for the simulation duration of 43 years(from 1992 to 2035), low salinity has shown significant improve in oil recovery as indicated in the representative plot of recovery factors in figure 55.

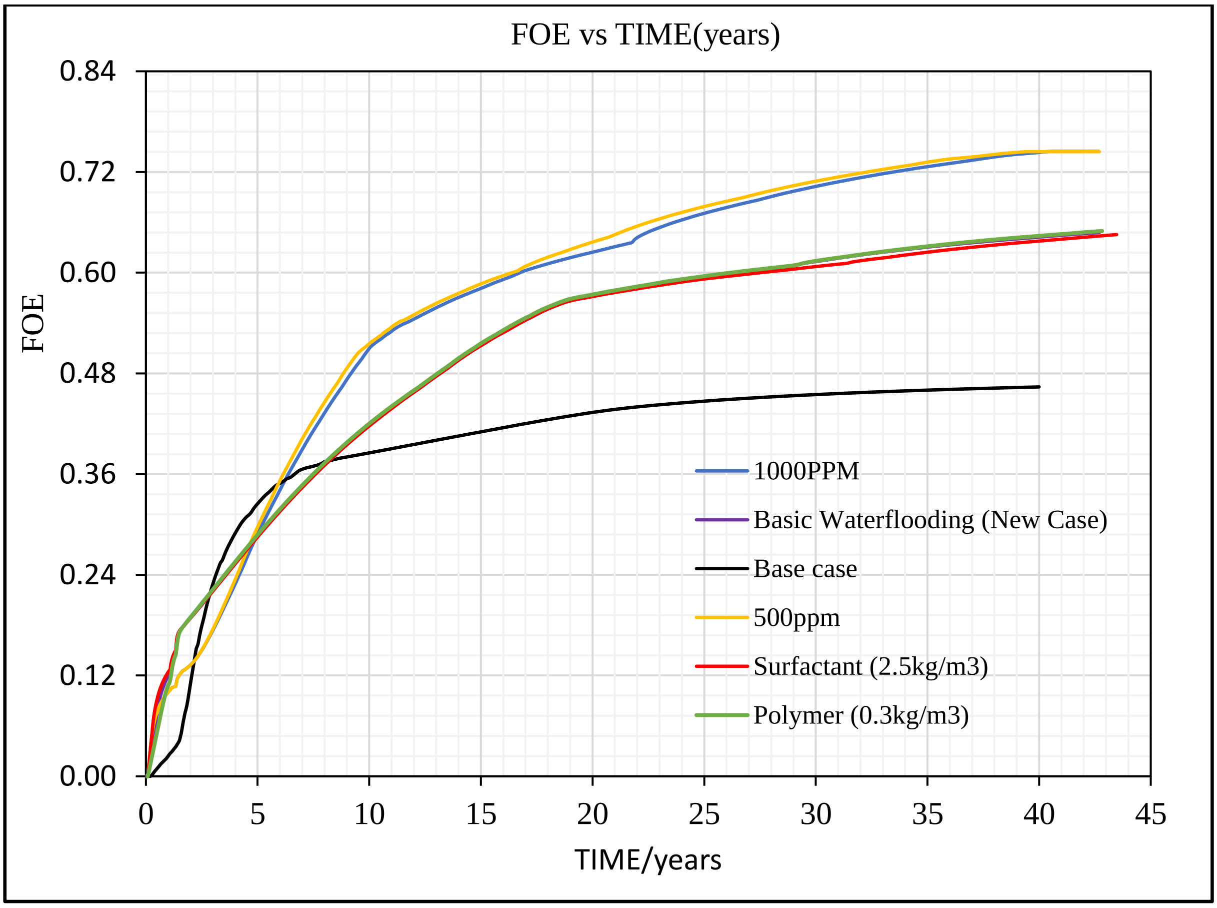


Figure 55: Comparison of all IOR methods implemented base on recovery factors

As observed from figure 56, surfactant and polymer flooding provide almost no effect to the oil recovery, when compared with low salt waterflooding. The results for surfactant and polymer flooding methods was considered to be non-economical. Thus, for economic evaluation polymer and surfactant injection methods will not be involved and the work will be focused on low salinity waterflooding which significantly has shown an improve in oil recovery.

5.2.6 Incremental Oil Recovery for LSW as Secondary and Tertiary Mechanisms.

Table 6 describe an incremental oil recovery for some of the salt concentration compared with conventional waterflooding. The observed incremental oil recovery suggests that the effect of injecting low salinity water contributed significantly in improving the oil recovery compares to the rest of the techniques. The maximum oil recovery is observed by injecting water with 1000ppm.

Table 6: Improved oil recovery for low salinity as secondary methods

CASES	Recovery Factor (%)	Incremental oil Recovery factor (%)
BWF(Base Case)	64.79	N/A
LSW (500pppm)	74.42	9.63
LSW (1000pppm)	74.46	9.67
LSW(5000ppm)	72.44	7.65
LSW (20000pppm)	71.33	6.54

Table 7 describes the incremental oil recovery for low salinity water flooding method compare with the high salt water flooding. The maximum incremental oil recovery is observed for the concentration of 1000ppm as it was observed when low salinity water injection applied as secondary method.

Table 7:Increase in oil recovery for low salinity water injection as tertiary method

CASES	Recovery Factor (%)	Incremental oil Recovery factor (%)
HighSal (HS)-Base Case	66.13	N/A
LowSal (LS) -500pppm	73.92	7.79
LowSal (LS)- 1000pppm	74.47	8.34
Low Sal-5000pppm	74.23	8.10
LowSal (LS)- 10000pppm	74.35	8.22
LowSal (LS)- 20000pppm	72.67	6.54

5.2.7 Economic Analysis Based on Incremental Oil and Gas Produced.

It was necessary to perform a simple economic analysis based on incremental oil and gas produced and evaluate if it is economic viable to apply low salinity waterflooding method since additional costs for installation of desalination system should be included. The revenue obtained from incremental oil and gas produced must be able to pay the cost for desalination system with profit for the project to be economical viable. The desalination facilities to convert sea water to low-salinity water (LoSal system) costs an approximate of 120 million USD (Rowland, 2013). This facility has a low-salinity waterflood injection capacity of more than 250,000 barrels of water per day which is approximately equivalent to 40,000sm^3/d, the system is sufficient to meet the injection demands for the two injectors as the maximum injection rate of 12,000sm^3/d was set for each well. This facility has been used by British Petroleum(BP) at the Gulf of Mexico (Rowland, 2013).

Table 8: Economic evaluation based on incremental oil and gas produced for three concentrations

CASES	Total incremental oil	Total incremental gas	Oil Revenue	Gas Revenue	Total Revenue	**Incremental Revenue**
	(bbl)	(SCM)	USD	USD	USD	**USD**
500ppm	3.63E+06	5.99E+08	2.76E+08	1.77E+06	2.78E+08	**1.58E+08**
1000ppm	3.65E+06	5.94E+08	2.78E+08	1.75E+06	2.80E+08	**1.60E+08**
20000ppm	1.81E+06	5.65E+08	1.37E+08	1.67E+06	1.39E+08	**1.90E+07**

From table 8, the cost for desalination system (120million USD) was subtracted from the total revenue as indicated to the incremental revenue. Thus, the highest revenue is observed for 1000ppm as indicated.

The highest incremental revenue is observed for the salt concentration of 1000ppm followed by 500ppm. All this analysis was based on the production time set to end up in 2035.

Consequently, the NPV analysis was performed for low salinity process as secondary technique based on the three salt concentrations as described in figure 56. It can be observed that applying water with salt concentration of 1000ppm resulted in maximum NPV compare to other concentration as seen in figure 56. Oil and gas prices used to achieve this part were 76 USD/BBL and 2.95 USD/1000SCM respectively which were the world prices for July 2018 (Bloomberg, 2018).

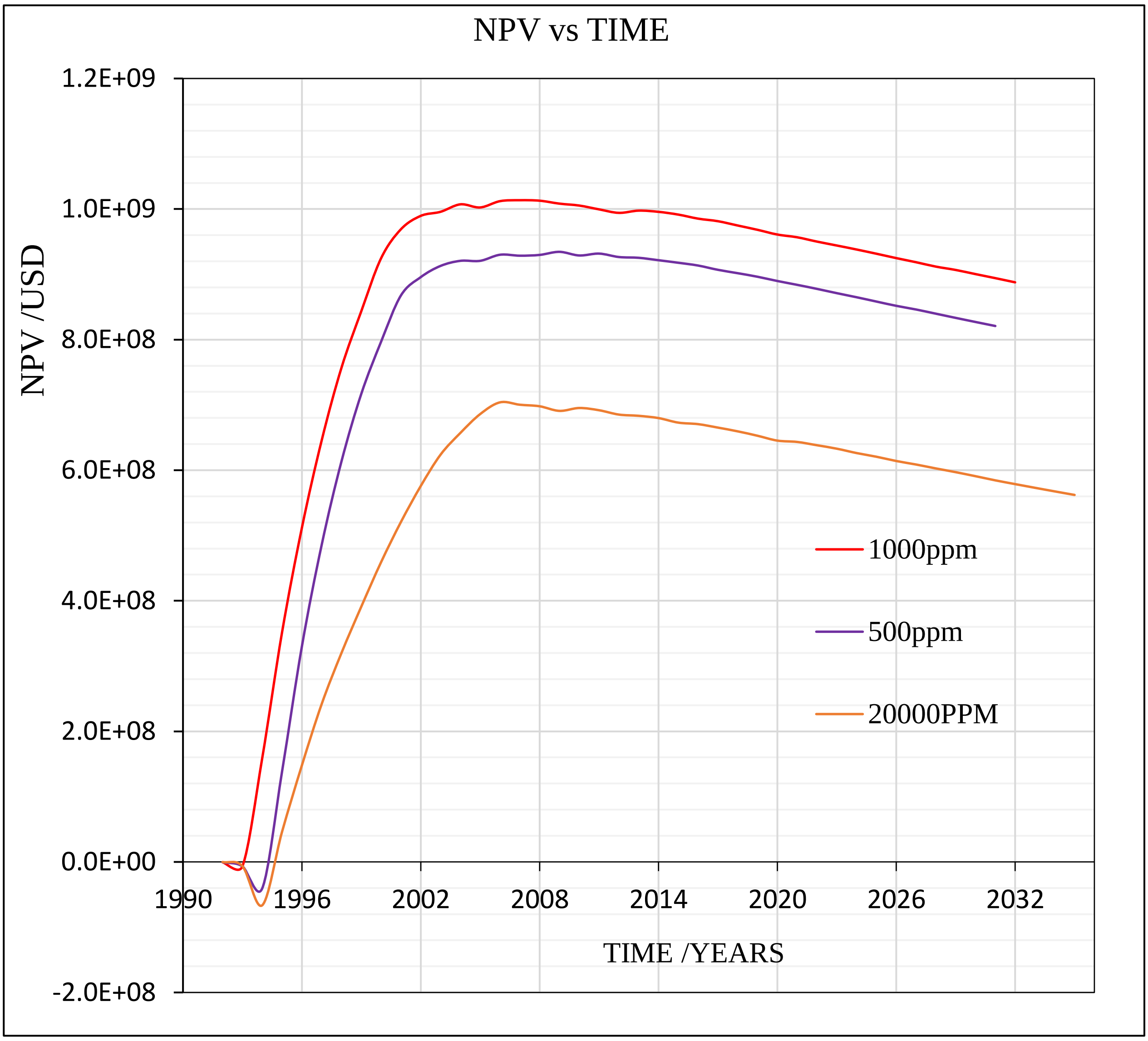


Figure 56: Economic evaluation based on NPV for low salinity as secondary method.

5.3 Discussion.

The simulation results obtained from the base case was 37.89% which was established from May 1992 to January 2001. The base simulation period was extended from 2001 to 2032 in which the maximum oil recovery factor of about 46.39% was achieved leaving behind large volume of oil unproduced.

The proposed case with new well placement improved the oil recovery significantly compare to the provided base case as indicated in the results section above . The maximum oil recovery attained from the proposed case was 64.79% for simulation period of about 43 years. This time was taken as the production time when compared with low salinity waterflooding methods.

Even though when simulation period was extended to 58 years small increase in oil recovery factor was observed which was 66.63% almost the same to that observed from polymer and surfactant. These results were considered to be non-economic and they could not be implemented in the field.

Significant improve in oil recovery has been attained when low salinity water was injected in the reservoir compare to conventional waterflooding, polymer and surfactant. Surfactant and polymer flooding provide very poor improve in oil recovery when compared to basic waterflooding. The maximum recovery factors observed when surfactant and polymer flooding were performed are 66.83% and 66.70% respectively which is almost same to basic waterflooding with oil recovery factor of 66.63%.

Very small improve in oil recovery factors between 0.2% to 0.1% for polymer and surfactant were observed respectively. For that case polymer and surfactant flooding techniques were left behind and the work focused into low salinity water flooding as a result of its positive effect on the oil recovery factor observed. From the base case when low salinity was applied the observed results show some improve in oil recovery (from 37.89% to 40.1%).

As secondary method low salinity waterflooding was implemented to the base case in which there was an improve in oil recovery from 37.89% by conventional water flooding to 40.1% when low salinity was applied. This result brought attention for low salinity water flooding as the best method to implement.

For all cases water cut limit was set as 95% and then as 97% and the simulation time was set to be 43 years (from 1992 to 2035). For the salt concentration of 500ppm, 69.97% of oil recovery was achieved with maximum water cut of 95% and 74.42% of oil recovery attained with maximum water cut of 97%. It can be observed that with maximum water cut of 97% oil recovery attained was the maximum and it should be considered.

For the concentration of 1000ppm, 69.95% and 74.46% were achieved for maximum field water cut of 95% and 97% respectively. The two concentrations were able to attain maximum recovery before 2035. For the concentration of 1000ppm, 69.95% and 74.46% were achieved for maximum field water cut of 95% and 97% respectively.

With 3000ppm, 70.08% of oil was recovered for FWCT of 95% and 74.18% for FWCT of 97% were achieved. Other concentrations of 5000ppm, 10000ppm and 20000ppm the maximum recovery factors achieved were 71.18%, 68.94% and 71.33% with FWCT of 97% respectively. For 20000ppm the reservoir was produced up to 2050 in which a maximum oil recovery of 74.57% attained which is almost the same as the recovery factor obtained by injecting 1000ppm up to 2035. Thus, 20000ppm was not economical compare to 1000ppm.

Based on incremental oil and gas produced simple economic analysis was performed. Even though to apply low salt water injection there is additional cost for installation of desalination system which costs about 120 million USD as reported by British Petroleum (BP). Simple economic evaluation based on the three best cases which were 500ppm,1000ppm and 20000ppm in comparison with conventional water flooding was achieved. The best concentration to apply was 1000ppm with a high NPV of about 8.88E+08 USD which is about 888 million USD. When using simple incremental oil recovery, the additional income resulted after subtracting the desalination system cost was 158 million USD, this amount is encouraging to implement the method.

As tertiary method low salinity method was applied, and the results were almost the same with secondary method. The difference is the production time since when applying low salinity as tertiary it should start with high salt water in this case the high salinity was 49000ppm which was injected up to 2013 then the concentration was reduced to the required salt concentrations from 500ppm to 20000ppm as in secondary case.

The maximum improvement in oil recovery of about 74.46% has been observed with salt concentration of 1000ppm. This concentration has been defined as full scale in the simulation model and it provide highest recovery factor for all cases (secondary and tertiary) see the plot in figure 57.

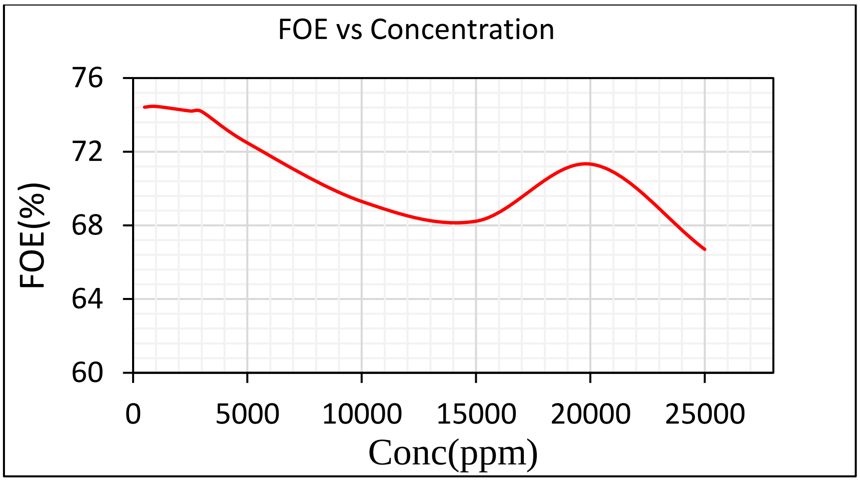


Figure 57: Description of recovery factor against salt concentrations

Total field gas production has observed to be maximum at lowest salt concentration which is 500ppm for this work. But it has been observed that injecting low salt water increases the wettability of the formation to become more water wet. Early water breakthrough has been observed when injecting water with lowest salt concentration, thus the lower the salt concentration the earlier the breakthrough.

The amount of water injected is inversely proportionally to the salt concentration of injection water (the smaller the salt concentration the higher the field water produced and injected).

As secondary recovery technique, low salinity improved the oil recovery by 9.67% compared to conventional water flooding using a salt concentration of 1000ppm and an improve in oil recovery of 8.34% was observed when low salinity was performed as tertiary method indicating that as secondary technique low salinity methods provide best results than tertiary method.

Based on incremental oil and gas produced simple economic analysis was performed to observe the viability of the process when additional cost for desalination system was added. The observed results show that the process is economical viable as indicated in table 7. NPV evaluation based on various salt concentration was performed and the observed results show that 1000ppm salt concentration has maximum NPV.

CHAPTER 6

6.1 Conclusion

In this work three IOR methods which are surfactant, polymer and low salinity water flooding were applied in the reservoir simulation model in order to come up with the best methods for the Statfjord I-1 segment in Gullfaks field. Polymer and surfactant injection gives a minor effect in the oil recovery after injection of about 15 years in which it can be concluded that the system did not support the injection of these chemicals. Polymer and surfactant attained an increase in oil recovery of about 0.1% and 0.2% respectively.

The proposed case with conventional water flooding attained an oil recovery of about 64.79% for simulation time of about 43 years (from 1992 to 2035). But the recovery factor attained when compared with polymer and surfactant is about 66.63% which was observed for simulation period of about 58 years.

With concentration of 2.5kg/m^3 surfactant attained a total oil recovery of about 66.83% and polymer injection resulted into an oil recovery of 66.7% after injecting the chemicals for 15years. In which case it was concluded that the two methods were not economical viable and the whole work focused into low salinity water injection.

Low salinity water has resulted into significant increase in oil recovery at Statfjord I-1 segment in the Gullfaks field and it has been proposed to be the best IOR method to be applied.

Different salt concentrations (from 500ppm -30000ppm) were implemented into the simulation model and two concentrations (500ppm &1000ppm) provided the best results. When simulation period was set to be 43 years, low salinity with concentrations of 1000ppm achieved a recovery factor of about 74.46%, an oil recovery factor of 74.42% was attained by injecting water with salt concentration of 500ppm while 20000ppm resulted to the oil recovery factor of about 71.33%. Thus, it is clearly that 1000ppm is the best concentration for the field.

Based on the economic analysis evaluated with regards to the incremental oil and gas produced and the current oil price and gas price (76.79USD/bbl & 2.95Btu/1000scm), the low salt water with concentration of 1000ppm is the best economically.

The amount of water injected and produced is inversely proportionally to the salt concentration of injected water (the lower the concentration the higher the amount of water injected and produced).

The displacement mechanism becomes more piston like as the salt concentrations becomes very low as observed from the results. Thus, to achieve a piston like displacement which is the most SWEEP efficient it is better to apply water with lowest salt concentrations such as 500ppm and 1000ppm used in this work.

As tertiary mechanism the maximum oil recovery factor attained was 74.57% with the salt concentration of 1000ppm as observed in figure 52. Even though this recovery was achieved by injecting the low salt water for 58 years which might result in higher OPEX when compared with secondary method which attained a maximum oil recovery factor of 74.46% for about 40 years . In this way it is suggested that low salinity as secondary technique is the best option to be applied since it can help to avoid increase in operating cost.

6.2 Recommendations.

Further study involving more IOR methods such as alkaline injection, assisted surfactant polymer flooding, combined low salinity and surfactant injection are recommended for the field so that the best method can be obtained.

Laboratory experiments based on the core samples from the Statfjord I-1 segment of Gullfaks field are highly recommended for all the IOR methods to be applied in order to develop reservoir rock and fluid data (properties) that can be compatible with the developed structure of the chemicals (polymer, surfactant and low salt water) that are to be applied.

For this work 500ppm was used as minimum salt concentration for injection test but further study with various concentrations below 500ppm are recommended to be performed to see their effects on the recovery factor.

Also, it is recommended to start the application of low salinity water injection as secondary drive mechanism since it seems to be more economical compared to when used as tertiary method. For the surfactant and polymer methods it is recommended to perform more experiments which can provide more realistic data for the field.

Very important to say that the work have been very complicated due to poor internet support and luck of close contact between students and their supervisors by these reasons it is highly recommended if possible to provide installations of the required software into their own computers lather than running them direct from NTNU farm.

CAPTER 7.

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1 LIST OF ABBREVIATIONS

Abbreviation	**Meaning**
IOR	Improved Oil Recovery
EOR	Enhanced Oil Recovery
CPU	Computer Processing Unit
GPU	Graphics Processing Unit
GNU	Great New Utility
CSEM	Controlled Source Electromagnetics
SCM	Standard Cubic Meter
MSCM	Million Standard Cubic Meter
AM	Acrylamide
AMPS	Acrylamide Propane Sulfonate
HPAM	Hydrolysed Polyacrylamide
IPV	Inaccessible Pore Volume
PDO	Petroleum Development of Oman
HEC	Hydro Ethyl Cellulose
NPV	Net Present Value
DLE	Double Layer Expansion
OOIP	Original Oil in Place
CDC	Capillary Destruction Curve
PDO	Petroleum Development of Oman
FWCT	Field Water Cut
FWIT	Field Water Injection Total
BWF	Basic Water Flooding

FWIR	Field Water Injection Rate
PPM	Parts Per Millions
FOPT	Field Oil Production Total
FGPT	Field Gas Production Total
MSCM	Million Standard Cubic Meter
BSCM	Billion standard cubic meters
BBL	Barrel
USD	United State Dollars
LSW	Low Salinity Water
MS	Medium Salt
LSE	Low Salinity Expansion
HS	High Salt
LS	Low Salt
MIE	Multi-component Ionic Exchange
DLE	Double Layer Expansion

APENDICIES.

1.New case (proposed case) with conventional waterflooding.

```
GRUPTREE
'I1'     'FIELD'  /
/
-- 31.000000 days from start of simulation ( 1 'MAY' 1992 )
DATES
1 'JUN' 1992 /
/
WELSPECS
'W1' 'I1'    19              21        1*  'OIL'  /
/
COMPDAT
'W1'   19        21        1          6          'OPEN'0          1*        0.178   3* 'Z'   /

/
WCONPROD
    'W1' 'OPEN' 'ORAT' 7500.  4* 180./
/
WECON
  'W1'  1*  1*  0.70  2*  'CON' 3*  0.95 'CON' /
/
DATES
1 'DEC' 1992 /
/
DATES
1 'JUN' 1993 /
/
WELSPECS
'W2' 'I1'    20 27    1*  'OIL'  /
/
COMPDAT
'W2'   20        27        1          2          'OPEN'0          1*        0.178   3* 'Z'   /
```

```
'W2'  20    28    2    3    'OPEN'0    1*    0.178  3* 'Y'  /
'W2'  20    28    3    4    'OPEN'0    1*    0.178  3* 'Y'  /
'W2'  20    29    4    5    'OPEN'0    1*    0.178  3* 'Y'  /
'W2'  20    30    5    5    'OPEN'0    1*    0.178  3* 'Y'  /
'W2'  20    31    5    5    'OPEN'0    1*    0.178  3* 'Y'  /
/

WCONPROD
   'W2' 'OPEN' 'ORAT' 7500.  4* 180./
/
WECON
  'W2'  1*  1*  0.70  2*  'CON' 3*  0.95 'CON' /
/
DATES
1 'SEP' 1993 /
/
WELSPECS
'W3' 'I1'    20   35    1*  'OIL'  /
/
COMPDAT
'W3'  20    33    1    3    'OPEN'0    1*    0.178  3* 'Z'  /
'W3'  20    33    2    3    'OPEN'0    1*    0.178  3* 'Z'  /
'W3'  20    33    3    4    'OPEN'0    1*    0.178  3* 'Y'  /
'W3'  20    34    4    4    'OPEN'0    1*    0.178  3* 'Y'  /
'W3'  20    35    4    4    'OPEN'0    1*    0.178  3* 'Y'  /
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'W3'  20    37    4    4    'OPEN'0    1*    0.178  3* 'Y'  /
/
WCONPROD
   'W3' 'OPEN' 'ORAT' 8500.  4* 180./
/
WECON
  'W3'  1*  1*  0.70  2*  'CON' 3*  0.95 'CON' /
/
```

```
DATES
1 'JAN' 1994 /
/
WELSPECS
'INJ1' 'I1'    12  25    1*  'WAT'  /
/
COMPDAT
  'INJ1'  12   25   1  12  'OPEN'  0   1.0/
/
WCONINJE
 'INJ1' 'WAT' 'OPEN'           'RATE'10000  1* 320./
  /
DATES
1 'JUN' 1994 /
/
WELSPECS
'INJ2' 'I1'    19  46    1*  'WAT'  /
/
COMPDAT
  'INJ2'  19   46   5  12  'OPEN'  0   1.0/
/
WCONINJE
 'INJ2' 'WAT' 'OPEN'           'RATE'10000  1* 320./
 /
 DATES
1 'DEC'1994  /
/
DATES
1 'JAN' 1995 /                                    1 'JAN' 2011 /
1 'JAN' 1996 /                                    1 'JAN' 2012 /
1 'JAN' 1997 /                                    1 'JAN' 2013 /
1 'JAN' 1998 /                                    1 'JAN' 2014 /
1 'JAN' 1999 /                                    1 'JAN' 2015 /
1 'JAN' 2000 /                                    1 'JAN' 2016 /
1 'JAN' 2001 /                                    1 'JAN' 2017 /
1 'JAN' 2002 /                                    1 'JAN' 2018 /
1 'JAN' 2003 /                                    1 'JAN' 2019 /
1 'JAN' 2004 /                                    1 'JAN' 2020 /
1 'JAN' 2005 /                                    1 'JAN' 2021 /
1 'JAN' 2006 /                                    1 'JAN' 2022 /
1 'JAN' 2007 /                                    1 'JAN' 2023 /
1 'JAN' 2008 /                                    1 'JAN' 2024 /
1 'JAN' 2009 /                                    1 'JAN' 2025 /
1 'JAN' 2010 /                                    1 'JAN' 2026 /
```

```
1 'JAN' 2027 /
1 'JAN' 2028 /
1 'JAN' 2029 /
1 'JAN' 2030 /
1 'JAN' 2031 /
1 'JAN' 2032 /
1 'JAN' 2033 /
1 'JAN' 2034 /
1 'JAN' 2035 /
/
-- END OF SIMULATION
```

2.The Surfactant Model Requirements in Eclipse 100

To implement chemical injection in the reservoir model, there are some key words which must be introduced in each section of the reservoir model so as to enable the injection of these chemicals.

For surfactant flooding table 6 describes the necessary key words to be introduced at each section of the model in order to achieve the flooding process.

Table 9: Keys words required for surfactant flooding in the eclipse model

RUNSPECT		**RESTRICTION**
SURFACT	Enable Surfactant model to be active	Required
PROPS		
SURFST	Define water- oil surface tension against surfactant concentration	Required
SURVISC	Specifies surfactant solution viscosity function	Required
SURFCAPD	Specifies capillary desaturation data in the model	Required
SURFROCK	Specifies rock properties for the surfactant model	Required for SURFADS
SURFADS	Specifies surfactant adsorption functions	Optional
REGION		
SURFNUM	Defines Surfactant miscible region numbers	Required
SCHEDULE		
WSURFACT	Specifies the surfactant concentration of a water injector.	Required

RUNSPEC

```
 TITLE
 GULLFAKS STATFJORD I1
 DIMENS
   30 60 12 /
 --NOSIM


 OIL
 WATER
 SURFACT
 GAS
 DISGAS
 METRIC



 FAULTDIM
   200 /

 GRIDOPTS
  'YES' 0 0 /
  ENDSCALE
 --                     ntendp   nsendp
    'NODIR'     'REVERS'     1       20  /
    TABDIMS
 --ntsfun   ntpvt  nssfun  nppvt  ntfip  nrpvt  notused  ntendp
     2               1      25      40       5      30 /

 REGDIMS
 --ntfip nmfip nrfreg  ntfreg mhisim  nmhstr
    5       2         0           0        0            1 /
    SMRYDIMS
   2000 /
   WELLDIMS
```

```
--nwmaxz  ncwmax  ngmaxz nwgmax
   20         100           10      15 /
```

3. Input Files for Surfactant Injection

```
SURFST
   -- surf          water-oil
   -- conc          surface tension
   -- kg/m3         (N/m)
    0.0             0.05
    1.0             1.0E-6
   10.5             1.0E-14  /
   /
  /
  SURFVISC
  --surfactant              solution water
  --concentration         viscosity at this
  --in the solution          surfactant concentration
  --kg/m3
      0.0                               0.42
      10.5                               5.00  /
      0.0                               0.42
      10.5                              5.00  /
  /
  SURFCAPD
  --log of          miscibility
  --capillary     function
  --number     0=immiscible, 1=miscible
     -8               0.0
     -7               0.0
     -6               0.2
     -5               0.5
     -4               0.7
```

```
   -3            1.0
   -2            1.0
   10            1.0 /
   -8            0.0
   -7            0.0
   -6            0.2
   -5            0.5
   -4            0.7
   -3            1.0
   -2            1.0
   10            1.0 /
/
SURFADS
--surfactant   surf conc
-- conc        adsorbed on rock
-- kg/m3        (kg/kg)= kg surfactant/kg rock
 0.0             0.000
 1.0             0.000
 5.0             0.000
10.0             0.000  /
 0.0             0.000
 1.0             0.000
 5.0             0.000
10.0             0.000  /
/
SURFROCK
--adsorption mass density
--index      of rock type
--               kg/rm3
    1            2650/
   1             2650 /
/
```

4.The Polymer Model in Eclipse 100.

When applying POLYMER injections in the reservoir some important key words needed to be input in Eclipse 100 model. Table 7 describe the necessary key words for polymer and low salinity waterflooding modification.

Table 10: Important key words for application of polymer flooding in Eclipse 100.

RUNSPECT		**RESTRICTION**
POLYMER	Enable Polymer model to be active	Required
PROPS		
PLYVISC	Specifies polymer solution viscosity function	Required
PLYROCK	Specifies rock properties for polymer flooding model	Required
PLMIXPAR	Polymer Todd-Longstaff mixing parameter for viscosity calculations	Required for SURFADS
PLYMAX	Specifies polymer/salt concentration for mixing calculations	Required
PLYADS	Specifies polymer adsorption functions	Optional
SCHEDULE		
WPOLYMER	Specifies the polymer concentration and salt in the injection stream of the well.	Required

```
RUNSPEC

TITLE

  GULLFAKS STATFJORD I1

  DIMENS

  30 60 12 /

  --NOSIM

  OIL

  WATER

  POLYMER

  GAS
```

```
  DISGAS

  METRIC

  FAULTDIM

  200 /

  GRIDOPTS

  'YES' 0 0 /

  ENDSCALE

  --    ntendp   nsendp

  'NODIR'     'REVERS'     1       20  /

  TABDIMS

  --ntsfun   ntpvt   nssfun   nppvt    ntfip   nrpvt  notused  ntendp

  2          1          25         40         5        30 /

  REGDIMS

  --ntfip  nmfip  nrfreg   ntfreg  mhisim  nmhstr

  5          2             0          0             0       1  /
```

5. Input files for Polymer flooding.

```
  -- Polymer Viscosity

PLYVISC

--Kg/m3    water viscosity

--            multiplier

  0.0       1.0

 10.5       10.0 /

  0.0       1.0

 10.5        10.0 /

/
```

```
  -- Polymer-Rock Properties
  PLYROCK
  -- dead   residual         mass             adsorption       maximum
  -- pore   resistance       density          index            polymer
  -- space          factor                                             adsorption
     0.16   1.5              2650.0           1                0.00040 /
     0.16   1.5              2650.0            1               0.00040 /
     /
  -- Polymer Adsorption
  PLYADS
  --polymer          polymer
  --concentration            concentration adsorbed by rock
  -- Kg/m3                    Kg/Kg
     0.0                     0.0000
    5.0                      0.00010
   10.5                      0.00040  /
    0.0                      0.0000
    5.0                      0.00010
   10.5                      0.00040  /
/
TLMIXPAR
 1.0 /
 1.0 /
```

```
-- Polymer-Salt Concentrations for mixing - maximum polymer and salt concentrations

PLYMAX

   --polymer          salt

   --concentration   concentration



   -- Kg/m3          Kg/m3

     10.50           0.0 /

   10.50             0.0 /

   /--END OF SIMULATION
```

6. Low Salinity model in Eclipse 100

To apply low salinity water in the reservoir model the necessary key words needed to be input in Eclipse 100 model are described in table 8.

Table 11: Necessary key words for low salinity water flooding in Eclipse 100

RUNSPECT		**RESTRICTION**
LOWSALT	Enables modeling of low salinity effects in the Brine model	Required
PROPS		
PVTWSALT	specify water PVT functions with salt present	Required
LSALTFUNC	Specify the low salinity fraction as function of the salt concentration in the grid block.	Required
REGION		
LWSLTNUM	Low-salt water-wet saturation function region numbers	Required
SOLUTION		
SALTVD	Specify salt concentration(s) versus depth for equilibration	Required
SCHEDULE		
WSALT	Specifies (Set) the salt concentration for injection wells	Required

```
   RUNSPEC
   TITLE
   GULLFAKS STATFJORD I1
   DIMENS
    30 60 12 /
   --NOSIM
OIL
WATER
LOWSALT
GAS
   DISGAS

   METRIC

   FAULTDIM
    200
   GRIDOPTS
    'YES' 0 0 /
   ENDSCALE
   --             ntendp  nsendp
     'NODIR'     'REVERS'      1    20  /
   TABDIMS
   --ntsfun       ntpvt   nssfun nppvt   ntfip  nrpvt   notused  ntendp
      2           1       25     40      5      30 /
```

```
REGDIMS
--ntfip nmfip nrfreg  ntfreg mhisim  nmhstr
5             2     0      0     0      1 /
```

7. Input Files for Low Salinity Waterflooding in The Model.

```
-- PVT-EGENSKAPER FOR VANN.

-- REF.TRYKK          BW              KOMPR.        VISK.

PVTWSALT

  308.2           0.00  /

--Salt conc.            Bw              Cw               Visc    Cv
  0.0             1.024           4.64E-05        0.42            0.0
  1.25            1.01            3.00E-06        0.52     0.0
  2.50            1.00            3.00E-06        0.52     0.0
  3.75            0.98            3.00E-06        0.52     0.0
  5.00            0.95            3.00E-06        0.52     0.0 /
   /
LSALTFNC
---unused     table
  0               1.0      1*
  20     0.0      1*
  /
  0               1.0      1*
  30     0.0      1*
  /
-- OLJE- OG GASS-TETTHET
-- OLJE                  VANN          GASS
DENSITY
-- 838.0                 1038.0                 0.809   /
-- 877.0                 1038.0                  0.809  /
   844.0                 1038.0                   0.809   /
/
---END OF SIMULATION
```