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Numerical Simulation on the Impact of Polymer Salt Concentration to Alkaline-Surfactant-Polymer Flooding to Residual Oil Recovery

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ABSTRACT

Chemical enhanced oil recovery process of most interest currently is alkaline-surfactant-polymer (ASP) flooding. ASP flooding has advantages over both surfactant-polymer flooding and alkaline-polymer flooding. Simulation of ASP flooding considers the chemical reactions between the alkali and the oil to form soap and between the alkali and both the minerals and brine. In this work, Schlumberger Eclipse simulator will be used to perform simulations on ASP flooding in NAP-2X well. Nine different cases will be considered with polymer salt concentration ranging from 7 ppm to 300 ppm. Biopolymer was used in this work due to its good viscofying property in high saline water which compared to polyacryamid with low efficiency in high saline water increasing polymer salt concentration had a positive impact on the field residual oil production. High salt concentration reduces and increases the polymer absorption and adsorption respectively, by an increase in the viscosity of polymer due to electrostatic repulsion in the polymer solution and a reduction in the surface area of adsorbent, access to polymer molecule. It was observe that, the flooded solution sweep efficiency increased with increasing polymer salinity.

Introduction

Chemical flooding, in particular Alkaline-Surfactant-Polymer (ASP) flooding, is of increasing interest because of high demand in energy, hence the need to increase oil production. Recent laboratory research has shown significant benefits to using surfactants at high pH even if the oil has a low acid number and thus little if any surfactant is generated in-situ, so high pH surfactant-polymer flooding is also of great current interest (Yugal, 2011).

This work will focus on modeling processes to improve oil recovery through the use of a displacing fluid that has a low interfacial tension (IFT) against the displaced crude oil. The IFT between brine and oil must be reduced from 10-30 dynes/cm to about 10-3 dynes/cm to reduce the residual oil saturation to nearly zero under typical reservoir flooding condition.

The effect of IFT on oil recovery is modeled by the capillary desaturation curve where residual oil saturation is correlated as a function of capillary number. To be able to obtain low IFT and achieve good oil recovery, surfactant and polymer are added to the injection water. Surfactant is responsible for reducing the IFT and consequently the residual oil saturation. However, polymer is also necessary for mobility control (Yugal, 2011).In a typical surfactant/polymer flood, a small slug of about 30% PV containing a relatively low concentration of surfactant and polymer is injected. The injection of the surfactant slug is followed by a polymer drive to maintain mobility control.

In alkaline/polymer flooding, only polymer and alkali are injected and the process relies solely on the generation of surfactant in-situ. Jennings et al. (1974) described recovery by emulsification and entrapment. In this mechanism, an emulsion formed by decreasing the IFT is subsequently trapped by the pore throats. This causes a reduction of flow in high permeability zones and results in an improvement of the effective mobility ratio. The effectiveness of alkaline flooding is attributed to a number of mechanisms. Johnson (1976) categorized the four most important mechanisms as: emulsification and entrainment, wettability reversal--oil-wet to water-wet, wettability reversal--water-wet to oil-wet, and emulsification and entrapment. The first mechanism, emulsification and entrainment, results from reduction of the IFT and the formation of an emulsion in which oil is entrained. If the emulsion is mobile, the oil saturation will decrease and oil will move through the reservoir. Injection of alkaline chemicals can also cause a reversal of wettability from either oil-wet to water-wet or vice versa. The change in wettability and subsequent readjustment of fluids within the pores favorably affects the relative permeability to the oil phase. Discontinuous residual oil can be reconnected and caused to flow.

When this wettability reversal is coupled with IFT reduction, the water flood residual oil saturation can significantly decrease (Yugal, 2011). The chemical enhanced oil recovery process of most interest currently is alkaline-surfactant-polymer (ASP) flooding. ASP flooding was first introduced by Nelson (1984) as co-surfactant-enhanced alkaline flooding. ASP flooding has advantages over both surfactant-polymer flooding and alkaline-polymer flooding. Simulation of ASP flooding considers the chemical reactions between the alkali and the oil to form soap and between the alkali and both the minerals and brine. The next chapter will provide a detailed description of the alkaline, surfactant and polymer flooding process.

A hypothetical producing well NAP-2X characterised with a sandstone lithology experienced low oil production rate at the surface than expected due to insitu reservoir pressure depletion. Alkaline-Surfactant-Polymer (ASP) flooding has been found to be the best chemical enhance recovery method for sandstone reservoirs with moderate API oil ranging from 28 – 35-degree API. Here, NAP-2X operators is faced with the challenge of determine the adequate polymer salt concentration which will improve the polymer viscofying power for a an improve mobility of residual oil. Hence, there is a need to perform numerical simulations on the impact of polymer salt concentrations to residual oil production.

This work is aimed at improving residual oil recovery by choosing an adequate polymer salt concentration for the implementation of Alkaline-Surfactant-Polymer (ASP) to X-G oil field. To this aim, simulations will be performed on this well based on the following objectives listed below, which are to determine the;

- field residual oil production total on application of polymer salt concentration of 7- 300 ppm by considering seven (7) different cases,
- effect of these cases on the field polymer adsorption rate,
- field water cut on application of these cases.

Literature Review

Oil production period mechanisms can be classified as primary, secondary and tertiary mechanisms. By the development of production time reservoir pressure is dropping, so different methods are used to control pressure and increase production. Most large oil fields are produced with some type of secondary pressure maintenance scheme, such as water flooding, gas flooding etc. Oil recovery mechanisms and their classifications are shown in Figure 2.1.

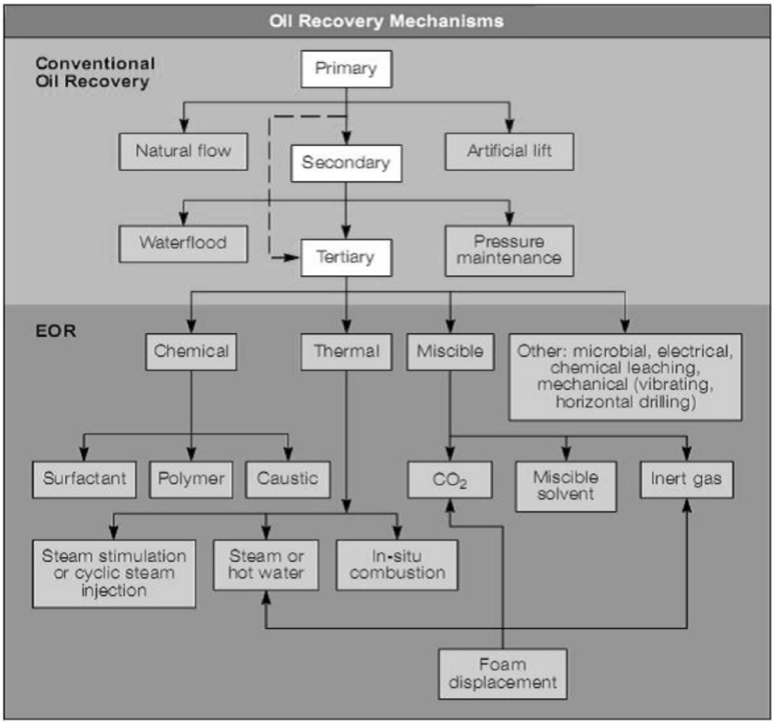
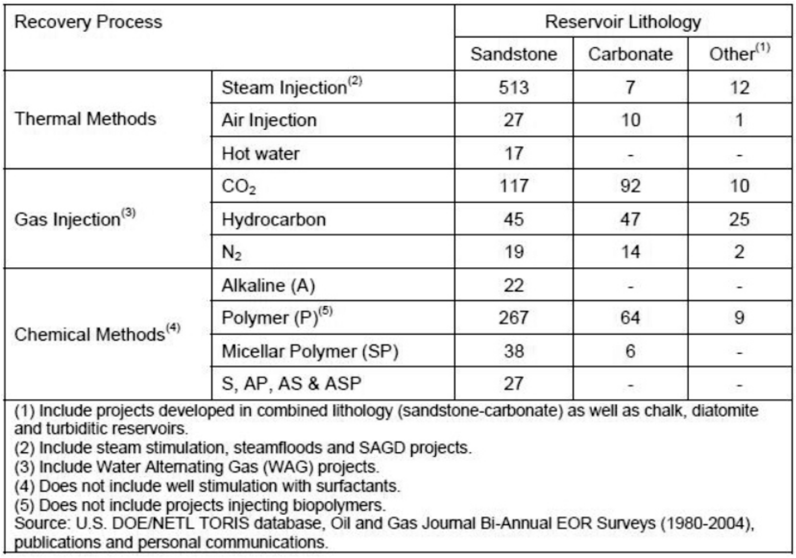


Figure 2.1: Oil Recovery Mechanism (Eldar, 2006).

Enhanced Oil Recovery Methods

EOR methods include two general titled methods of non-thermal and thermal with specific mechanisms for each one. Mainly, non-thermal production methods are widely used for conventional reservoirs. When secondary oil recovery is not enough to continue adequate production tertiary recovery begins, but only when the oil can still be extracted profitably. This depends on the cost of the extraction method and the current price of crude oil. When prices are high, previously unprofitable wells are brought back into production; when they are low, production is curtailed. Tertiary oil recovery reduces the viscosity of the oil to increase oil production. Application of different kind of chemicals has been found profitable. Combinations of chemicals may be applied as premixed slugs or in sequence. The choice of the method and the expected recovery depend on many considerations, economic as well as technological. Methods for improving oil recovery, in particular those concerned with lowering the interstitial oil saturation, have received a great deal of attention both in the laboratory and in the field (Eldar, 2006).

Table 2.1: EOR methods implemented by lithology description (Eldar, 2006) .



Recovery Process		Reservoir Lithology		
		Sandstone	Carbonate	Other(1)
Thermal Methods	Steam Injection(2)	513	7	12
	Air Injection	27	10	1
	Hot water	17	-	-
Gas Injection(3)	CO_2	117	92	10
	Hydrocarbon	45	47	25
	N_2	19	14	2
Chemical Methods(4)	Alkaline (A)	22	-	-
	Polymer (P)(5)	267	64	9
	Micellar Polymer (SP)	38	6	-
	S, AP, AS & ASP	27	-	-

(1) Include projects developed in combined lithology (sandstone-carbonate) as well as chalk, diatomite and turbiditic reservoirs.
(2) Include steam stimulation, steamfloods and SAGD projects.
(3) Include Water Alternating Gas (WAG) projects.
(4) Does not include well stimulation with surfactants.
(5) Does not include projects injecting biopolymers.
Source: U.S. DOE/NETL TORIS database, Oil and Gas Journal Bi-Annual EOR Surveys (1980-2004), publications and personal communications.

Alkaline Flooding

Alkaline flooding is an enhanced oil recovery method in which an alkaline chemical such as sodium hydroxide, sodium orthosilicate or sodium carbonate is added to injected water. The alkaline chemical reacts with certain types of oils and forms surfactants inside the reservoir. Eventually, the surfactants play a big role to increase oil recovery by reducing interfacial tension between oil and water. The alkaline agents lead to the displacement of crude oil by raising the pH of the flooding water. The reaction between alkaline and acidic components in crude oil forms in situ surfactant at the oil-brine interface. Then the crude oil is mobilized by the mixture and the mixture removes oil from the pore spaces in the reservoir. Normally, alkaline flooding has been used only in reservoirs containing specific types of high-acid crude oils.

The process can be modified by the addition of surfactant and polymer to the alkali which gives an alkaline-surfactant polymer (ASP) enhanced oil recovery method, essentially a less costly form of micellar-polymer flooding (Fathi, 2008; Zhang, 2008).Chemical EOR is commercially available under limited conditions such as reservoir characteristics, depth, salinity, and pH level. The high cost of chemicals and reservoir characterization studies needs to be reduced to allow expanded use of chemical enhanced oil recovery methods before full implementation can take place. The addition of silicates is an enhancement to alkaline flooding. The silicates have two main functions:

- It is as a buffer, maintaining a stable high pH level to produce a minimum interfacial tension.
- It improves surfactant efficiency through the removal of hardness ions from reservoir brines, thus reducing adsorption of surfactants on rock surfaces.

It should be noted that, alkaline flooding is not recommended for carbonate reservoirs because of the profusion of calcium and the mixture between the alkaline chemical and the calcium ions can produce hydroxide precipitation that may damage the formation. The main profits of alkaline are lowering interfacial tension and reducing adsorption of anionic surfactants that decrease costs and make ASP a very smart enhanced oil recovery process provided the consumption is not too large. By numerical simulation process, the alkaline model can be planned and optimized to ensure the proper propagation of alkali, effective soap and surfactant concentrations to promote low interfacial tension and an encouraging salinity gradient. Alkaline flooding is a complex process where interfacial tension reduction is not always the key mechanism. Depending on the rock and crude properties, emulsification and wettability alteration can play a major role in oil recovery from mixed-wet naturally fractured carbonates (Fathi, 2008; Zhang, 2008).

Mechanisms of Alkaline

Application of alkaline flooding has four mechanisms:

- Emulsification and Entrainment” in which flowing alkali entrains the crude oil.
- Wettability Reversal” (Oil-Wet to Water-Wet) in which change of wettability affects change in permeability that makes increase in oil production.
- Wettability Reversal” (Water-Wet Oil-Wet to) in which we get low residual oil saturation through low interfacial tension.
- Emulsification and Entrapment” in which movement of emulsified oil improves sweep efficiency.

Alkali solution is chosen based on some factors such as price and availability at the flooding area, the pH level, the temperature and mineralogy of the reservoir and composition of the mixed water.

In-Situ Soap Generation

Eventually, soap in situ is generated by reaction of alkali agents such as sodium carbonate with acids in crude oil. Acid number is used as a measure for the possible amount of crude oil to produce soap. The acid number is the quantity of KOH to neutralize the acid in oil expressed in mg KOH/g oil. Fan and Buckley (2006) and Hirasaki (2007) discussed the new protocols for acid number measurements. The making of soap is modeled by the partitioning of acid in the crude oil (HAo) to water according to the solubility as:

where; $HA_o \xrightleftharpoons{K_D} HA_w$

$$K_D = \frac{[HA_w]}{[HA_o]}$$

Haw is the concentration of acid in water,

K_D is the partition coefficient.

By the time the acid in water will separate in the aqueous phase to generate soluble anionic surfactant (A-) referred to as soap according to the expression below:

$$HA_{W} + OH^{-} \underset{}{\overset{K_a}{\rightleftarrows}} H_2O + A^{-}$$

The reaction above is one of the sources of alkaline consumption since the alkali uses hydrogen to generate soap by the following process;

$$HA_{W} \overset{K_a}{\rightleftarrows} H^{+} + A^{-}$$

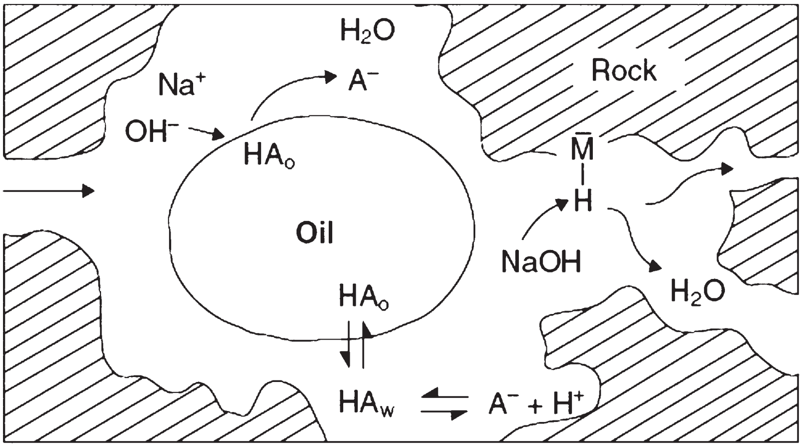


Figure 2.1: Schematic of alkaline recovery process (Fathi, 2008; Zhang, 2008).

Aqueous Reactions

Buffered reactions can be shown as aqueous reactions. General example of the buffered reactions which are of interest to alkaline flooding process is the carbonate and bicarbonate buffered solutions.

$$H_2O \Leftrightarrow H^{+} + OH^{-}$$

$$H^{+} + CO_3^{2-} \Leftrightarrow HCO_3^{-}$$

$$2H^{+} + CO_3^{2-} \Leftrightarrow H_2CO_3$$

Ion Exchange Reactions with Clay

Ion exchange with clays in the rock causes a postponement in chemical breakthrough time where it has the same effect as adsorption. These reactions are relatively rapid reactions and are reversible. The hydrogen/sodium and sodium/calcium are example of key ion exchange reactions (Eldar, 2006). The hydrogen/sodium ion replace can have a big impact on alkali consumption in proportion to the cat ion exchange capacity.

$$\overline{H}^{+} + Na^{+} + OH^{-} \Leftrightarrow \overline{Na}^{+} + H_2O$$

where H+ and Na+ are the adsorbed ions on the rock

Dissolution and Precipitation Reactions

Dissolution and precipitation reactions constitute one of the most important reactions in alkaline flooding. Insoluble salt formation by reaction with hardness ions such as calcium and magnesium as a result of ion exchange from the rock surfaces is example of dissolution and precipitation reactions. These reactions can cause significant loss of alkaline over an extended period of time.

$$Ca^{2+} + CO_3^{2-} \Leftrightarrow CaCO_3$$

As an example kaolinite, $Al_2Si_2O_5(OH)_4$ is found in most sandstone formations. The dissolution of kaolinite at high pH can result in generation of aqueous types such as

$$\text{Kaolinite} - 4OH^{-} + 3H_2O \Leftrightarrow 2\ Al(OH)_4^{-} + 2\ H_3SiO_4^{-}$$

Surfactant Flooding

Surfactant flooding is an encouraging enhanced oil recovery method. After a long term water-flooding process, some amount of oil is left trapped in the reservoir due to a high capillary pressure. To get moveable oil, surfactant agents are introduced into the reservoir to increase oil recovery by lowering the interfacial tension between oil and water. Trapped oil droplets are mobilized due to a reduction in interfacial tension between oil. The coalescence of these drops leads to a local increase in oil saturation. An oil bank will start to flow, mobilizing any residual oil in front. Eventually, the ultimate residual oil is determined by interfacial tension between oil and surfactant solution behind the oil collection (Eldar, 2006).

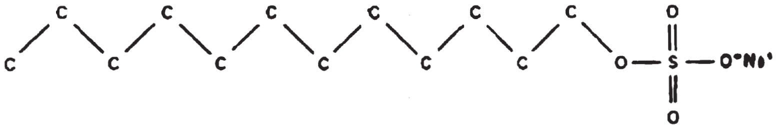
Interfacial Tension

Low interfacial tension (IFT) between crude oil and water is significant for successful enhanced oil recovery by surfactant flooding. Generally, main requirement of alkaline/surfactant processes is targeting of ultralow interfacial tensions. For this purpose, the right surfactant should be selected and evaluated at low and economic concentrations. On the other hand, maintaining low IFT during the displacement process is a critical challenge because of dilution and adsorption effects in the reservoir. Consequently, oil displacement efficiency will be handled by IFT change from the static equilibrium value. The effect of changing IFT on the in-situ behavior of given oil/brine system was studied by carrying out IFT measurements with two surfactants using pre-equilibrated oil/brine/surfactant solutions (Fathi, 2008; Zhang, 2008).

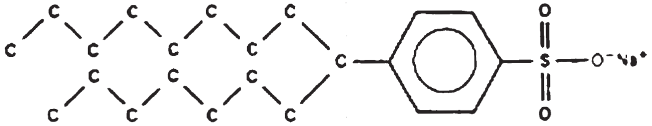
To have better understanding of the process, displacement was studied in reservoir and Berea cores. The parameters varied were type and concentration of injected surfactant, slug size and chase fluid. Through the use of the effective IFT concept, the oil displacement efficiency demonstrated good correlation with capillary number. The core flood experiments further suggest that other factors may affect the movement efficiency and should be included in the design of a cost-effective ASP flood (Eldar, 2006).

Structure of Surfactant

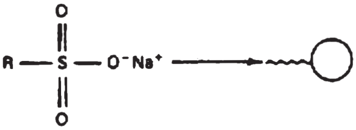
Hydrophilic head group and a lipophilic tail together contains surfactant molecule. The head refers to the solubilizing group – the lyophilic or hydrophilic group in aqueous systems and the tail refers to the lyophobic or hydrophobic group in water. The whole molecule is called an amphiphile telling a dual-nature which makes the surfactant reside at the interface between the aqueous and organic phases, lowering the interfacial tension. The molecular structure is shown in figure below.



(a) Sodium dodecyl sulfate



(b) Texas no. 1 sulfonate



R = hydrocarbon group (nonpolar)

(c) Commercial petroleum sulfonates

Figure 2.2**:** Structure of molecular surfactant (Fathi, 2008; Zhang, 2008).

Surfactants types and some materials

During surfactant flooding process general types and some materials in use are follows:

- Anionic Surfactants.
- Non-Ionic Surfactants.
- Solubilizer.
- Chelating Agent.
- Cosolvents.
- Polymer.
- Large Hydrophobe Surfactants.
- Hydrophobes.

● Classification of Surfactants

Surfactants are classified to some specific types in terms of Ionic nature of surfactants. These species are anionic, nonionic, cationic and amphoteric chemicals. Description for each group is given below. (Eldar, 2006).

Anionic

The charge on the molecular head group can be negative, positive and neutral. Anionic surfactants are defined due to negative charge on the head group. This kind of chemicals have some specifications such as stability, reducing IFT, low adsorption character. That is why they can be considered effective chemical EOR components. Some examples can be shown as anionic surfactants like carboxyl (RCOO-M+) and sulfonate ($RSO_{3-}M+$)

Cationic

Cationic surfactants have positive charge compared to anionic surfactants. Addition of cationic surfactants to polymer flooding can increase efficiency by changing wettability

Nonionic

Due to neutral charge on the head group some surfactant types are called nonionic. For salinity stability analyses nonionic surfactants are highly used

Amphoterics

Amphoterics class consists of two or more of the other classes. The composition of these surfactants can be mixture of anionic, cationic and others.

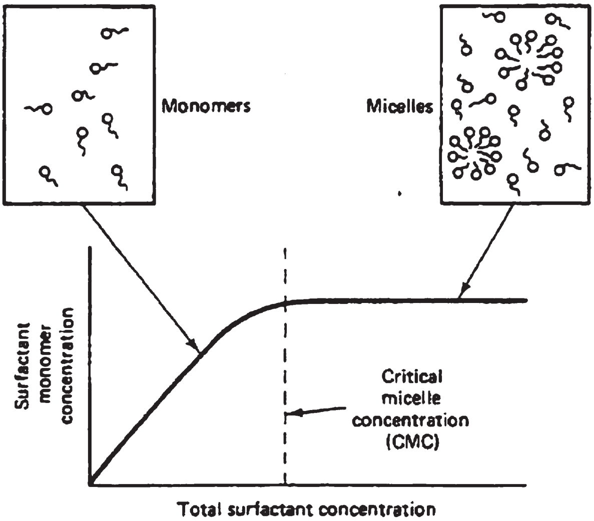


Figure 2.3: Critical Micelle Concentration (Farid, 2011)

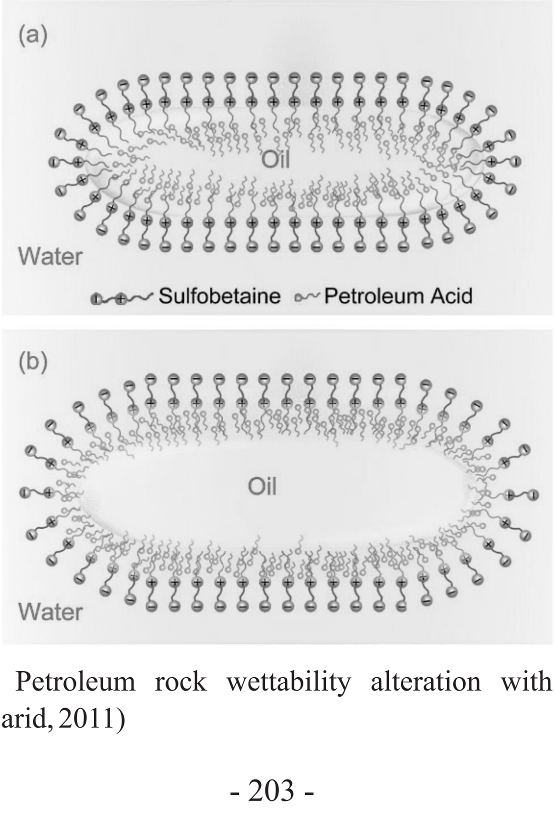


Figure 2.4: Petroleum rock wettability alteration with surfactant molecule. (Farid, 2011)

Surfactant flooding potential in the North Sea

Implementing of surfactant injection in the North Sea has been discussed in the SPOR MONOGRAPH mainly for the fields like the Oseberg and Gullfaks. Based on analyses and studies implementing of surfactant project for the North Sea is encouraging and taking economic side for getting higher efficiency and profit it is recommended to inject surfactant early period of time before the reservoir is completely water-flooded. Improved Oil potential for surfactant flooding on the Norwegian continental shelf is estimated to be 100 million Sm3 (Fathi, 2008; Zhang, 2008).

Polymer Flooding

Polymer flooding is an enhanced oil recovery method that uses polymer solutions to increase oil recovery by increasing the viscosity of the displacing water to decrease the water/oil mobility ratio. During polymer flooding, a water-soluble polymer is added to the injected water in order to increase water viscosity. Depending on the type of polymer used, the effective permeability to water can be reduced in the swept zones to different degrees. It is believed that polymer flooding cannot reduce the residual oil saturation (Sor), but it is still an efficient way to reach the Sor more quickly or/and more economically. Adding a water-soluble polymer to the water-flood allows the water to move through more of the reservoir rock, resulting in a larger percentage of oil recovery. Polymer gel is also used to shut off high-permeability zones. In the process, the volumetric sweep is improved, and the oil is more effectively produced. Often, infectivity is one of the critical factors. The polymer solution should therefore be a non- Newtonian and shear thinning fluid, i.e., the viscosity of the fluid decreases with increasing shear rate (Fathi, 2008; Zhang, 2008).

There are three potential ways in which polymer flooding makes the oil recovery process more efficient:

- Through the effects of polymers on fractional flow.
- By decreasing the water/oil mobility ratio.

- By diverting injected water from zones that have been swept.

The most important preconditions for polymer flooding are reservoir temperature and the chemical properties of reservoir water. At high temperature or with high salinity in reservoir water, the polymer cannot be kept stabile, and polymer concentration will lose most of its viscosity (Sheng, 2011).

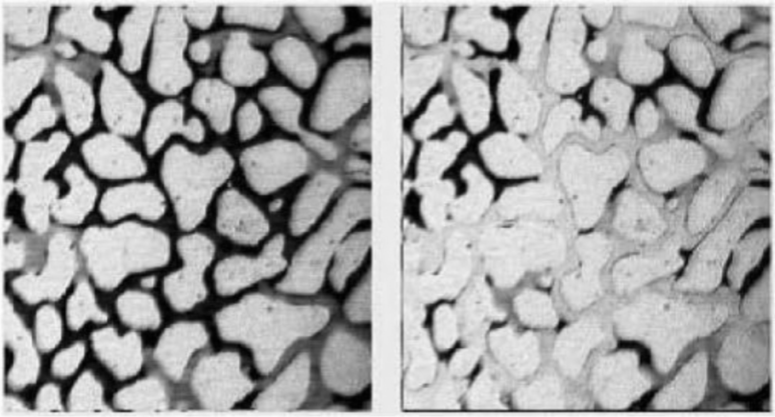

After Water Flood **After PAM Flood**

Figure 2.5: Comparison of oil saturation after polymer flooding and water flooding (Sheng, 2011).

Polymer Types
Polymer is a term used to describe a very long molecule consisting of structural units and repeating units connected by covalent chemical bonds. The term is derived from the Greek words: polys meaning many, and “meros” meaning parts. The key feature that distinguishes polymers form other molecules is the repetition of many identical, similar, or complementary molecular units.

There are mainly two types of polymers which might be effective in reduction of mobility ratio:

Polyacrylamides
Condensation polymers and their performance depend on the molecular

weight and degree of hydrolysis. When partially hydrolyzed, some of the acryl amide is replaced by or converted into acrylic acid. This tends to increase the viscosity of fresh water but reduces the viscosity of hard waters. Polyacrylamides can absorb many times of its mass in water while ionic substances like salt cause the polymer to release some of its water.

They are relatively cheap, develop good viscosities in fresh water, and adsorb on the rock surface to give a long-term permeability reduction. The main disadvantages are their tendency to shear degradation at high flow rates, and their poor performance in high salinity brine.

Biopolymers

Biopolymers are derived from a fermentation process. It has a smaller molecular weight than polyacrylamide. Its molecular structure gives the molecule great stiffness, a characteristic that gives the biopolymer excellent viscosifying power in high salinity water. However, they have less viscosifying power than polyacrylamide in fresh waters. They have good viscosifying power in high salinity water and good resistance to shear degradation. Also, they are not retained on the rock surface and thus easily propagate into the formation than polyacrylamide, which can reduce the amount of polymer required for a flood (Sheng, 2011).One of the key parameters which need to be considered in polymer selection are:

- Injectability into the reservoir.
- Ability to move through the formation.
- Provide required viscosity.

Polymer parameters

Polymer Solution Viscosity

The polymer solution viscosity is a key parameter to improve the mobility ratio between oil and water and adjust the water intake profile. As injection viscosity increases, the effectiveness of polymer flooding increases. The viscosity can be affected by a number of factors. First, for a given set of conditions, solution viscosity increases with increased polymer molecular weight. Second, increased polymer concentration leads to higher viscosity, and increased sweep efficiency. Third, as the degree of HPAM hydrolysis increases up to a certain value, viscosity increases. Fourth, as temperature increases, solution viscosity decreases. Polymer degradation can also decrease viscosity. Fifth, increased salinity and hardness in the reservoir water also decreases solution viscosity for anionic polymers.

The effectiveness of a polymer flood is directly determined by the magnitude of the polymer viscosity. The viscosity depends on the quality of the water used for dilution. A change in water quantity directly affects the polymer solution viscosity. Normally water quantity changes with the rainfall, ground temperature and humidity during the seasons. The concentrations of Calcium and Magnesium ion in the water source are lower in summer and higher in winter. Consequently, the polymer viscosity is also relatively higher in summer and lower in winter (Zhang, 2008).

Two factors should be considered when choosing polymer molecular weight. First, the polymer with highest Mw is practical to minimize the polymer volume. Second Mw must be small enough so that polymer can enter and propagate effectively through reservoir rock.

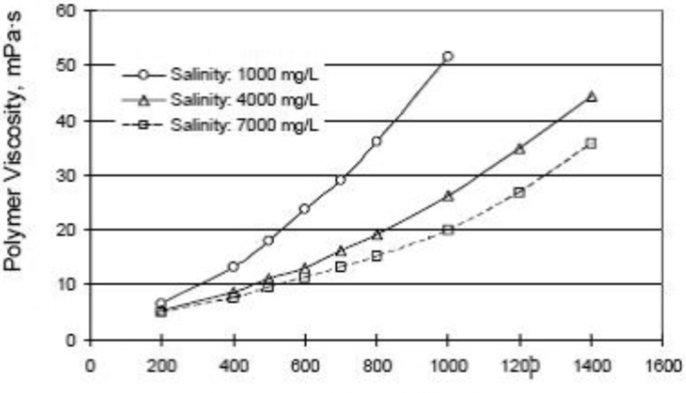


Figure 2.6: Viscosity versus concentration for different salinities (Zhang, 2008).

Polymer Molecular Weight

The effectiveness of a polymer flood is affected significantly by the polymer molecular weight (Mw). As illustrated in Figure 9, polymers with higher Mw provide greater viscosity. For many circumstances, larger polymer Mw also leads to improved oil recovery. Core flood simulation verifies this expectation for cases of constant polymer slug volume and concentration (Sheng, 2011).

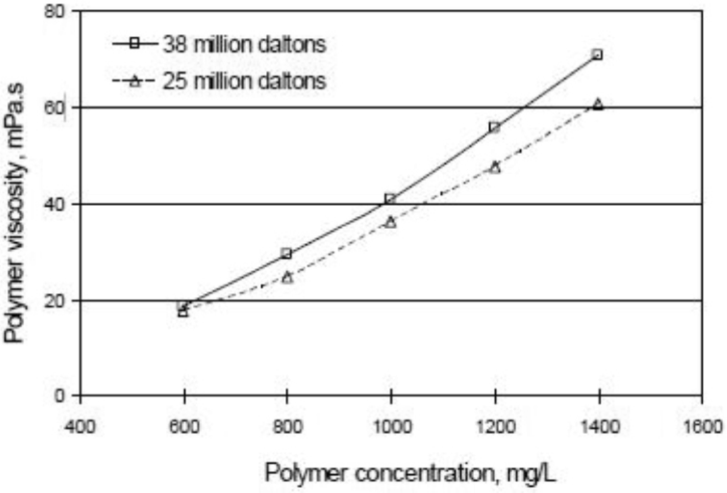


Figure 2.7: Viscosity versus concentration (Sheng, 2011).

Polymer Solution Concentration

The polymer solution concentration dominates every index that changes during the course of polymer flooding:

- Higher injection concentrations cause greater reductions in water cut and can shorten the time required for polymer flooding. For a certain range, they can also lead to an earlier response time in the production wells, a faster decrease in water cut, a greater decrease in water cut, less required pore volumes of polymer, and less required volume of water injected during the overall period of polymer flooding. As polymer concentration increases, enhanced oil recovery increases and the minimum in water cut during polymer flooding decreases.
- Above a certain value, the injected polymer concentration has little effect on the efficiency of polymer flooding. For a pilot project, the economics of injecting higher polymer concentrations should be

considered. The polymer solution concentration has a large effect on the change in water cut. However, consideration should also be given to the fact that higher concentrations will cause higher injection pressures and lower injectivity. For individual wells, the concentration can be adjusted to meet particular conditions.

Polymer Flooding Effects

Polymer Adsorption

The amount of polymer adsorbed depends on the nature of the polymer and the rock surface. Both physical adsorption of polymer on solid surfaces and polymer retention by mechanical entrapment appear to play a big role in total polymer retention in a reservoir. Generally, three phenomena have been observed regarding polymer adsorption:

- Laboratory tests often indicate higher adsorption than field performance.
- Adsorption is significantly less in consolidated cores than in sand packs.
- Adsorption increases with increasing water salinity.

Typical field adsorption values range from 20 to more than 500Ib/acre-ft. Laboratory adsorption values range from 30 to several hundred jug m/gm.13 note that laboratory results often cannot be extrapolated to predict polymer adsorption in oil reservoirs, polymer retention is also important (Sheng, 2011).

Polymer Retention

Retention of polymer in a reservoir can result from adsorption, entrapment or with improper application, physical plugging. Polymer retention tests are usually performed a polymer flood oil recovery test. If polymer retention tests are conducted with only water initially present in the core, a higher level of retention will result from the increased surface area available to the polymer solution in the absence of oil. Effluent samples from the core are collected both the polymer injection and a subsequent water flush. These samples are analyzed for polymer content. From a material balance, the amount of polymer retained in the core is calculated. Excessive retention will increase the amount of polymer that must be added to achieve the desired mobility control. The level of polymer retained in a reservoir depends on a number of variables: permeability of the rock, surface area, nature of the reservoir rock (sandstone, carbonate, minerals, or clays), nature of the solvent for the polymer (salinity and hardness), molecular weight of the polymer, ionic charge on the polymer, and the volume of porosity that is not accessible to the flow of polymer solution (Sheng, 2011).

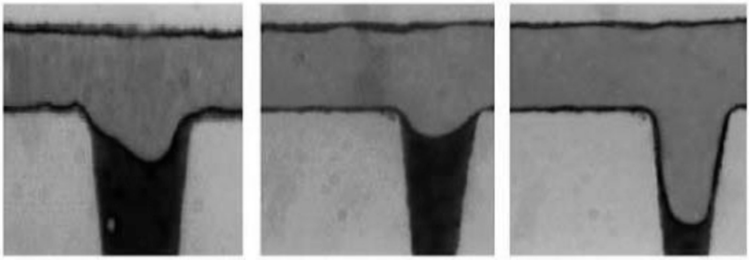
Inaccessible Pore Volume

Polymer solutions propagate through porous media at a velocity different from that of water because of adsorption and inaccessible pore volume. Adsorption tends to move the front edge of a polymer slug at a slower velocity than the water bank, and inaccessible pore volume tends to move the polymer slug at a higher velocity than the water bank. The combination of the two effects results in a smaller slug that is shifted forward. The phenomenon of inaccessible pore volume was first reported by Dawson and Lantz. They showed that all the pore space may not be accessible to polymer molecules and that this allow be accessible to polymer molecules and that this allows polymer solutions to advance and displace oil at a faster rate than predicted on the basis of total porosity. They also concluded from laboratory results that about 30% of the total pore volume in the rock samples used was not contacted by the polymer solution.

The inaccessible pore volume can have beneficial effects on field performance. The rock surface in contact with the polymer solution will be less than the total pore a volume, thus decreasing the amount of polymer adsorbed. More importantly, if connate water is present in the smaller pores inaccessible to the polymer, the bank of connate water and polymer depleted injection water that precedes the polymer bank is reduced by the amount of inaccessible pore volume. However, movable oil located in the smaller pores will not be contacted by the polymer in some cases, and therefore it may not be displaced (Yuga, 2011).

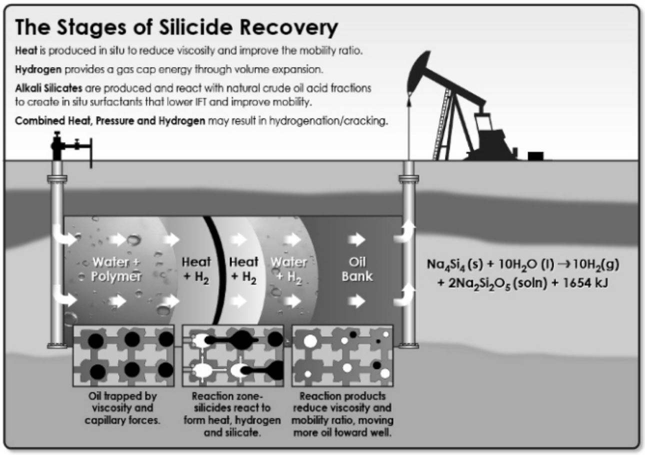
Displacing residual Oil in “Dead Ends”

Effect of polymer were studied in a laboratory using a glass etched core model with pore diameter of 250Urn, the oil in the core was first flushed by water until the water cut was 100%, then glycerin with viscosity of 30cP until 100% water cut, and then finally by polyacrylamide fluid (viscosity 30 cp) until 100 % water cut. The results showed that viscosity alone cannot mobilize the residual oil as shown by the glycerin flooding. However, the polymer fluid mobilized 4 times the amount of residual oil out of the dead ends than the glycerin. The polymer "dragged" the residual oil from the dead ends because of its elastic properties, where the fluids in front can pull the fluid behind and beside it. The elastic properties are lacking in the water and glycerin (Sheng, 2011).



After Water Flood **After Glycerin Flood** **After PAM Flood**

Figure 2.8: Residual oil in dead ends flushed by water, glycerin and polyacrylamide (Sheng, 2011)



The Stages of Silicide Recovery

Heat is produced in situ to reduce viscosity and improve the mobility ratio.

Hydrogen provides a gas cap energy through volume expansion.

Alkali Silicates are produced and react with natural crude oil acid fractions to create in situ surfactants that lower IFT and improve mobility.

Combined Heat, Pressure and Hydrogen may result in hydrogenation/cracking.

$$Na_4Si_4\,(s) + 10H_2O\,(l) \rightarrow 10H_2(g) + 2Na_2Si_2O_5\,(soln) + 1654\ kJ$$

Figure 2.9: Silicide Recovery of oil using water-polymer flooding (Sheng, 2011).

Mobility Control

During a standard water-flood the sweep efficiency achieved is usually not as good as desired. A fingering effect of the water flooding into the oil bank is usual problem at the bottom the use of a polymer has reduced the effect of fingering significantly, and as described above by avoiding fingering i.e. decreasing water saturation behind the front we are achieving piston like displacement and by that volumetric sweep can be improved. Polymer is often added to the surfactant solution to increase its apparent viscosity giving potential to increase both volumetric sweep efficiency and displacement efficiency (Yuga, 2011).

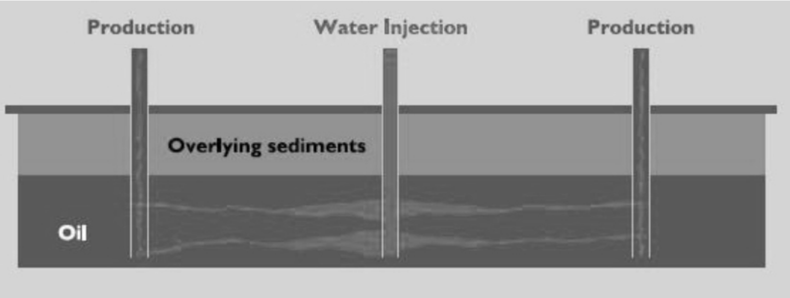


Figure 2.10: Fingering effect with water flooding (Sheng, 2011)

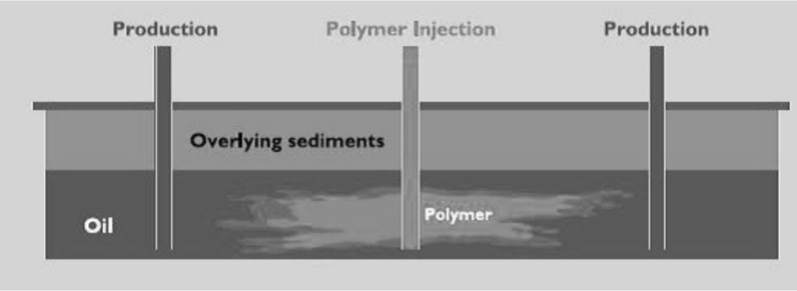


Figure 2.11: Decreased effect of fingering with polymer flooding (Sheng, 2011).

Methodology

Alkaline-Surfactant-Polymer Flooding Simulation

In this work, Schlumberger Eclipse simulator will be used to perform simulations on ASP flooding in NAP-2X well. Seven (7) different cases will be considered based on the polymer salt concentration as shown in table 3.1 below.

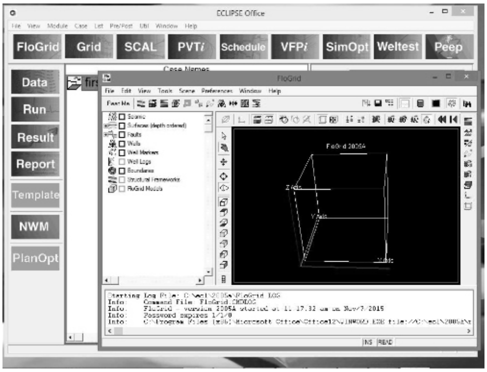
Biopolymers will used in this work as the adequate polymer for this project based on the theory that they can withstand high saline solution and are characterized with a good viscofying property which favors displacing fluid efficiency compared to polyacrylamid with low efficiency in high saline water.

Table 3.1: Polymer salt concentration for various cases

Polymer type	Bipolymers	
Cases	Polymer salt concentration	Unit of measurement
Case 1	7	ppm
Case 2	50	ppm
Case 3	100	ppm
Case 4	150	ppm
Case 5	200	ppm
Case 6	250	ppm
Case 7	300	ppm

Simulation tool

Schlumberger Eclipse 2005 reservoir simulator will be used to develop a 3-D Cartesian model of NAP-2X oil well and to simulate possible oil production profile for each chemical enhance recovery method.



```
Starting Log File: C:\ecl\2005a\FloGrid.LOG
Info:     Command File: FloGrid.CMDLOG
Info:     FloGrid - version 2005A started at 11:17.32 am on Nov/7/2015
Info:     Password expires 1/1/0
Info:     C:\Program Files (x86)\Microsoft Office\Office12\WINWORD.EXE file://C:\ecl\2005A\r
```

Figure 3.2: Schlumberger Eclipse 2005 reservoir simulator interface

Table 3.3: NAP-2X well data

Reservoir	Parameter	Amount	Field Unit
Dimensions	Length	150	ft.
	Width	150	ft.
	Height	17.5	ft.
Reservoir Properties	Datum Depth	8500	ft.
	Datum Pressure	4800	Psia
	OWC	6175	ft.
	GOC	6017.5	ft.
Rock Properties	Horizontal Permeability	100	mD
	Vertical Permeability	10	mD
	Rock compressibility	4.0×10^{-5}	Psi^{-1}
	Porosity	0.25 (for all grids)	dimensionless
Fluid Properties	Oil Density	53	$lb./ft^3$
	Water density	64	$lb./ft^3$
	Gas density	0.00001	$lb./ft^3$
	API gravity	34	degrees

3.3 Oil recovery efficiency calculation

$$RE = \frac{\text{Initial oil in place - Residual oil}}{\text{Initial oil in place}} \times 100\% \qquad \text{........... Equation 3.1}$$

Where; RE = Recovery Efficiency

Results and Discussion

Field Oil in Place

The field oil in place a measure of the total residual oil volume left after depletion with time. Figure 4.2 shows that the residual oil volume in the reservoir before the implementation of ASP flooding was 94,000 stb. It could be observed that at the end of approximately 0.55 years, case 7 had the lowest residual oil volume of about 61,500 stb compared to case1 with residual oil volume 70,000 stb. The plots in figure below show that, an increase in polymer salt concentration leads to a decrease in residual oil volume.

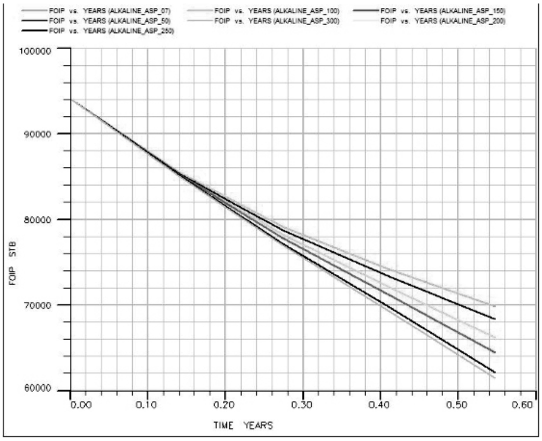


Figure 4.1: Field oil in place for all cases

Field Oil Production Total

From the figure below, it is observe that case 7 had the highest oil production profile of 33,000 stb, while case 1 had the lowest recovery of 24,000 stb approximately. But it was noticed that the difference in oil recovery in cases 6 and 7 were close compared to case 5, implying that as more salt is added to the polymer solution, the lower the field recovery. Therefore, more addition of salt will have a little or no effect on oil recovery with time.

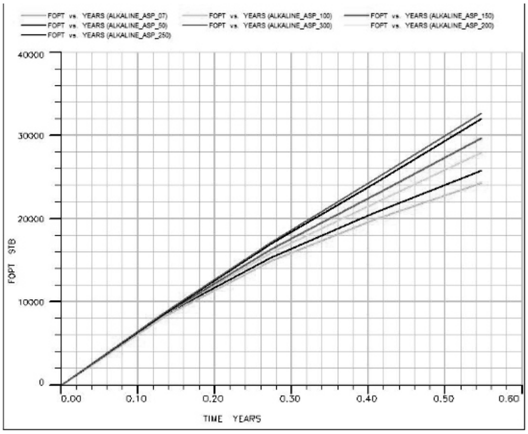


Figure 4.2: Field oil production total for all cases

Field Pressure

As a result of pressure depletion in the reservoir causing oi to be immobile, ASP flooding was implemented with varying polymer salt concentration. Case 7 increased the filed pressure from 4000 psia to 4800 psia at the end of 0.55 years. From 0.14 years to 0.27 years, the field pressure dropped due to

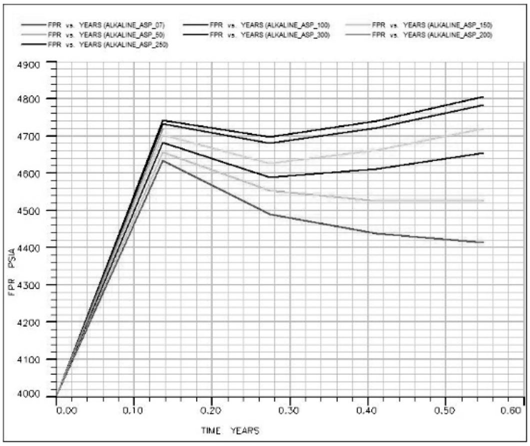


Figure 4.3: Field pressure for all cases

Field Polymer Adsorption

From literature, polymer permeability increases with increase in salinity as the salt concentration increases, the charge shielding takes place due to positively charged ions of salt (Na^+) this the hydrodynamic radius of polymer molecule reduces, thereby preventing pore plugging which may reduce the formation permeability to oil. Moreover, the salt concentration may affect the displacement efficiency and volumetric sweep efficiency of the polymer flood. High salt concentration reduces and increases the polymer absorption and adsorption respectively, by an increase in the viscosity of polymer due to electrostatic repulsion in the polymer solution and a reduction in the surface area of adsorbent, access to polymer molecule. There the polymer sweep efficiency increases with increasing salinity

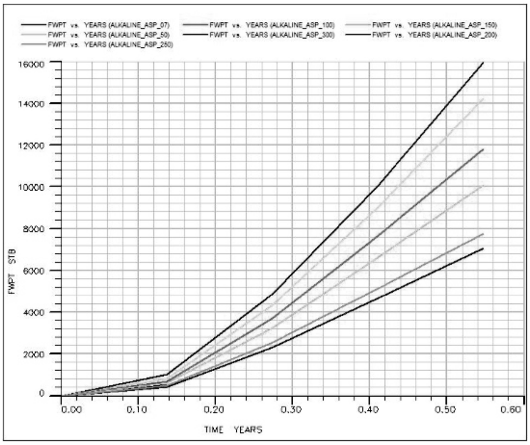


Figure 4.4: Plot of field polymer adsorption with time

Field Water Cut

The field water cut is the ratio of the amount of water produce at surface condition to the water volume at reservoir condition. Figure 4.5 below shows that, case 1 had a higher field water cut of about 0.59 at the end of the simulation period. Low polymer salinity causes the polymer to be absorbed to the rock surface thereby reducing the flooded chemical solution viscosity which may lead to the occurrence of viscous fingering.

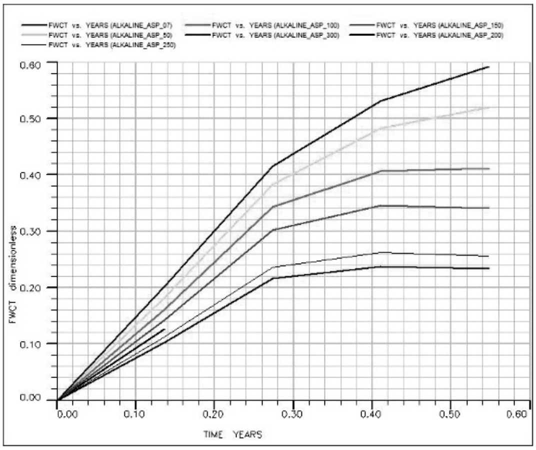


Figure 4.5: Field water cut for all cases

Figure 4.5 shows the volume of water produced for all cases. Case 1 yielded a higher water production 16,000 stb, compared to the rest indicating that an increase in salt concentration will lead to a decrease in field water production. Hence, the lesser the amount of water produced, the larger the water drive volume to mobilize the residual oil. This accounts for the high oil recovery in case 7.

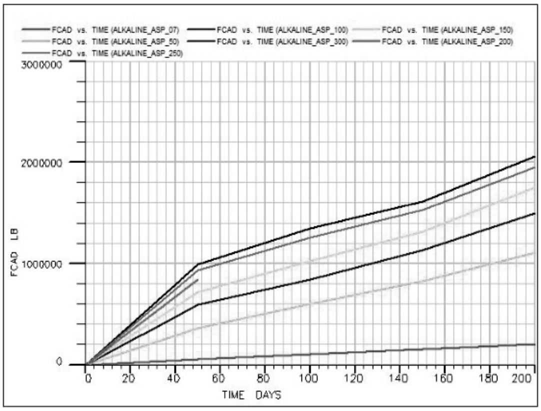


Figure 4.6: Field water production total for all cases

Conclusion and Recommendation

Conclusion

From this study, an increase in polymer salt concentration had a positive impact on the field oil production. ASP flooding with polymer salt concentration of 300 ppm had the highest field oil production of 33,000 stb with the lowest water cut of 0.24 compared to cases 1 to 6. Comparing cases 6 and 7 FOPT plot was found to be virtually linear with a low deviation of about 1,000 stb compared to other cases where there was a significant increase in production. This signifies that, the choice of polymer salt concentration could range from 250 – 300 ppm. Exceeding this range may cause adverse damage to the formation integrity as a result of residual salt concentration in the rock pore.

Viscous fingering and pore permeability reduction due to polymer absorption insitu can be avoided by increasing the salinity of the flooded polymer molecule. High salinity increases the Bipolymer viscosity, thereby improving the volumetric sweep efficiency of the flooded chemical.

Therefore, NAP-2X will achieve an incremental oil recovery from 0.27 to 0.35 with a polymer salt concentration of the ASP chemical of 300 ppm.

Recommendation

It could be recommended that, Further studies should be done on the effects of pH on the Alkaline solution on ASP flooding performace.

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