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Numerical Simulation of Low Salinity Water Flooding Assisted with Chemical Flooding for Enhanced Oil Recovery

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Abstract

World proved oil reserve gradually decreases due to the increase production but decrease new field discovery. The focus on enhance oil recovery from the existing fields has become more interesting in the recent years. Since waterflooding has been used in practices in secondary recovery phase for long time ago, the low salinity waterflooding is possible to apply as tertiary recovery phase. Another effective enhance oil recovery method is chemical flooding especially, nowadays, when the price of chemical is not a big issue compared to oil price. Both low salinity and chemical flooding method have been trialed and success in laboratory studies and some field tests. Moreover the salinity sensitivity on chemical flooding has been studied and both positive and negative results were proposed. Because new technology has been developing day by day in order to get higher oil recovery, the new technology as the combination of low salinity waterflooding and chemical flooding has been studied in this report.

In this thesis, the literature of low salinity water flooding, alkaline flooding, surfactant flooding, polymer flooding and alkaline-surfactant-polymer flooding (ASP) have been reviewed. The mechanisms of each method that affect to oil recovery and salinity sensitivity on each chemical flooding method have been summarized. All of those studies showed the benefit of chemical to the low salinity water flooding. the result of literature reviews has turned to the numerical simulation part.

The simulation has been carried out on a 3 dimensional synthetic model by using Eclipse 100 as the simulator. The model is heterogeneous with patterns variation in permeability and porosity. The effect of low salinity in water flooding, alkaline flooding, surfactant flooding, polymer flooding and ASP flooding have been observed in many aspects.

The main role of low salinity effect in water flooding is wettability changing from oil-wet to water-wet. The low salinity water in the first water flooding phase give the positive effect but not much different compared to overall recovery. The low salinity in chemical solution influences an additional oil recovery in all combinations. Mainly, low salinity increases polymer solution viscosity that can improve sweep efficiency of polymer flooding. In alkaline flooding and surfactant flooding, the salinity is need to be optimized to optimum salinity condition corresponding to optimum alkaline concentration and surfactant concentration, where creates the lowest IFT. The range of secondary flooding for alkaline and surfactant flooding is when they reach the optimum concentration. In case of polymer, the viscous polymer solution can impact longer as the polymer injection range. In term of low salinity in tertiary water flooding, it influences better oil recovery than high salinity water flooding. Therefore, it can be concluded that low salinity water flooding gives a positive effect to overall result when combined with chemical flooding. The recommendations are also available for further study.

Preface

This Master thesis is submitted to the Norwegian University of Science and Technology (NTNU) for partial fulfillment of the requirements for the degree of Master of Science in Petroleum Engineering.

The Master thesis has been performed at Department of Petroleum Engineering and Applied Geophysics, NTNU, Trondheim, with Professor Jan Åge Stensen.

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I have not been able to survive living here without a great support from Bangkok Café restaurant: Pa' Deang for the part time job opportunity and P'nang for everything that I could not write all within this page! Also, many Thai people in Trondheim. Finally, I would like to thank my family for their love and moral support through 25 years of my life. I would say that I have not been able to stay through these 2 years until I reach this point without their teaching.

Natthaporn Atthawutthisin

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Nomenclature

$\emptyset$	porosity
σ	Interfacial tension between the displaced and the displacing fluids
ρ_r	mass density of the rock formation
λ	Mobility
ω	Todd-Longstaff mixing parameter
$A_{sd}(C_{alk})$	adsorption multiplier at alkaline concentration
C_a	alkaline concentrations
C_a^a	alkaline adsorption concentration
$C_{s,p}^a$	surfactant/polymer adsorbed concentration
C_p^a	polymer adsorption concentration
C_pC_n	polymer and salt concentrations respectively in the aqueous phase
D_z	cell center depth
Q_w	water production rate
R_k	relative permeability reduction factor for the aqueous phase due to polymer retention
S_{dpv}	dead pore space within each grid cell
T	transmissibility
μ	displaced fluid viscosity
μ_{sh}	shear viscosity of the polymer solution (water + polymer)
$\mu_{w,eff}$	effective water viscosity
μ_s	Surfactant viscosity
μ_{ws}	Water-surfactant solution viscosity
μ_w	Water viscosity
$\mu_{s,eff}$	effective viscosity of salt
$\mu_{a,eff}$	effective viscosity of the water (a=w), polymer (a=p) and salt (a=s).
ϑ	pore velocity
ASP	Alkaline, surfactant and polymer
AS	Alkaline and surfactant
AP	Alkaline and polymer

SP	Surfactant and polymer
CMC	Critical Micelle Concentration
C_{unit}	A unit constant
$C_A(C_{surf})$	adsorption as a function of local surfactant concentration
EOR	Enhanced Oil Recovery
IFT	Interfacial Tension
K	Permeability
MD	Mass Density
N_C	Capillary Number
p_{cow}	Capillary pressure
$P_{COW}(S_W)$	Capillary pressure from the initially immiscible curve scaled according to the end points
P_{ref}	Reference pressure
$PORV$	Pore volume in a cell
S_{orw}	Residual oil saturation after water flooding
ST	Interfacial tension
$ST(Csurf)$	Surface tension with present surfactant concentration
$ST(Csurf=0)$	Surface tension with no surfactant present
FOE	Field Oil Efficiency
$FOPR$	Field Oil Production Rate
$FWCT$	Field Water Cut
FPR	Field Pressure

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Chapter 1

Introduction

1.1 Introduction

Today global energy demand is growing, while the existed reserves in conventional reservoir are depleting and the rate of replacement of the produced reserves by new discoveries has been also declining steadily in the last decade (BP, 2011). Enhanced oil recovery (EOR) from existing fields has become more and more important.

Water flooding was first applied to maintain pressure after primary depletion and has become the most widely adopted improved-oil-recovery (IOR) technique. In 1959, the first research showed that oil recovery factor increased when salinity of injection brine reduced was documented (Rezaei Doust, 2010). Since then, low salinity water flooding (LSW) has been announced as an emerging enhanced oil recovery technique in which the salinity of the injected water is controlled to improve oil recovery versus conventional, higher-salinity water flooding. Corefloods and single-well chemical tracer tests have shown that the low salinity water flooding can improve basic water flooding recovery by about 5 to 38%. However, many laboratories and organizations have grappled with the opportunities and problems associated with identifying, reproducing, and explaining the effects of LSW (Morrow, N. and Buckley, J., 2011). An effect, which is supported from several studies, is improving reservoir wettability to become more favorable water-wet mechanisms (Tang and Morrow 1997; Tang and Morrow 1999; Morrow et al. 1998; Webb et al. 2005; Jerauld et al. 2008). Therefore it is interesting to bring this point for further study.

Among the various EOR, chemical enhanced oil recovery (CEOR) has been also used worldwide for many decades. It has been labeled an expensive method, and field applications have been almost completely stopped during the past two decades worldwide except China. Because we are facing the difficulty of replacing depleting reserves with “cheap” oil and rising oil price, CEOR has drawn increasing interest from oil companies until nowadays (Henthorne, L., et al., 2011). A fundamental CEOR is surfactant flooding (S) that used to reduce interfacial tension (IFT) between oil and the displacing fluid Experimental data show that the injected surfactant causes the capillary number increases, resulting the residual oil saturation decreases. Therefore, as IFT is reduced through the addition of surfactants, the ultimate oil recovery. In alkaline flooding (A), the surfactants, which reduce IFT, are generated in situ by the chemical reaction between injected alkaline and naphthenic acids in the crude oil. Besides, polymer flooding (P), which increases the viscosity of displacing fluid, is used for mobility control to improve sweep efficiency (Lake, 1989). However, the synergy of ASP makes the alkaline-surfactant-polymer process more robust and results in a wider range of application conditions. The formation of in-situ surfactant from alkaline can reduces the requirement of surfactant and polymer in ASP slug while the combination of AS can create the ultralow IFT condition and polymer can control the sweep efficiency of all process to be even better (Hirasaki et al. 2004).

One would think that the combination of LSW and CEOR method should also have added benefits to oil recovery. Actually, there have been both positive and negative results on recovery from the studies of salinity sensitivity on CEOR. Thigpen (1991) proposed that the increase salinity of the brine affected negatively to the formation of in-situ surfactants and it partition at the oil/water interface. Meanwhile, The experiments of Glover (1979) concluded that in low salinity condition or type II(-) system is better because type II(+) or high salinity system and much of the surfactant retention could be caused by phase trapping, while much of this retained surfactant could be remobilized with a low-salinity drive. Moreover, a recent core flood study comparison of high- and low-salinity water and polymer (Mohanty, 2011) demonstrated that adding polymer to the low-salinity water could increase the oil recovery to an extra 10% above the low salinity water flooding.

New technology is always important to the industry. This is a reason why researchers have never stop with one solution but even find the better solution. Therefore, it is interesting to test this new application and find out whether it could produce an even greater recovery and also investigate its procedure. Thus, in this study, the combination of LSW with alkaline, surfactant, polymer and ASP have been studied to reach the objective as merging the effects from all methods; new technology to increase oil recovery.

1.2 Objectives

1) Examine the mechanisms and the salinity influences of low salinity water flooding, alkaline flooding, surfactant flooding, polymer flooding and ASP flooding from literature reviews.

2) Acquire the numerical simulation background (Eclipse-100) for low salinity water flooding, alkaline flooding, surfactant flooding, polymer flooding and ASP flooding cases.

3) Evaluate the effect of salinity in low salinity water flooding, alkaline flooding, surfactant flooding, polymer flooding and ASP flooding by simulating the synthetic reservoir model based on defined reservoir properties and real alkaline, surfactant and polymer properties in term of phenomenon and recovery results.
    a. The effect of low salinity water flooding to the enhanced recovery.
    b. The effect of salinity in water injection (starting from the first day of production) to the single chemical flooding and ASP flooding in the secondary phase recovery.
    c. The effect of salinity in the single chemical solution and ASP solution used in secondary phase recovery.
    d. The effect of ranges of low salinity and single chemical flooding in the secondary recovery phase.
    e. The effect of salinity in tertiary water flooding posterior to the single chemical flooding in secondary phase recovery.

1.3 Scope of Work

This thesis work was begun by doing literature study of research topics including the mechanisms of individual method: low salinity water flooding, alkaline flooding, surfactant flooding, polymer flooding, and AP/AS/SP flooding. Also, the effects of salinity to each individual method were summarized as well. These can be used as fundamental background to analyze the results and associated phenomenon.

Prior of the numerical simulation part, the base data file was created. The reservoir properties and basic data were included in the synthetic model. The proper oil and water relative permeability, salt concentration weighting factor relationship were found for applying to high and low salinity water flooding cases. Alkaline and surfactant properties were taken directly from the formal studies, while polymer properties, particularly, the viscosity data as function of salinity and polymer concentration, were researched and calculated to put in polymer flooding model.

In numerical simulation part, the reference case was run with continuous high salinity water flooding. The low salinity water flooding was studied to determine the continuous flooding for whole production period, the day to start the secondary recovery phase, the effect of salinity gradient in the secondary phase and the range of secondary phase that was followed by high salinity flooding as tertiary phase. The secondary recovery phase study of chemical flooding models had the same topics for alkaline, surfactant and polymer flooding that were the effect of the chemical concentration, effect of salinity in chemical solution and effect of salinity in the first water flooding resulting to chemical flooding. For ASP flooding, it was divided to AP/AS/SP flooding and were investigated the effect of each chemical type to the combined solution and the effect of salinity in the combined solution. The tertiary recovery phase studies of chemical flooding were also same to each chemical flooding that were the effect of range of secondary recovery phase and effect of salinity in the tertiary water flooding. Oil recovery was the main observed factor from the result. However, the phenomenon of oil production, water-cut and field pressure were also analyzed and discussed with the supported researches.

1.4 Thesis Organization

The thesis is divided into six main chapters. This report organization part describes the short detail in each chapter that can clarify the reader to get the big picture of this report. The detailed organization is outlined below.

In **Chapter 1, introduction**, it includes this introduction, which states the introduction and the objective of this Master thesis. The overview of this work is also summarized in this chapter. Then, it is followed by **Chapter2 literature reviews**. This chapter describes technical background composed of fundamental mechanisms and the salinity relationship of each flooding method. This part is useful for understanding the basic theory and leads to the comprehending in the result and discussion. The next is **Chapter 3 Overview of Numerical Simulation of Low Salinity combined with Alkaline/ Surfactant/ Polymer and ASP Flooding**. This chapter presents the description of synthetic model, constrains of model and simulation and the properties of all fluids used in the simulation. This part can also be followed to create the new low salinity water flooding model, alkaline flooding, surfactant flooding, polymer flooding and ASP flooding model for future study on the related topics. In **Chapter 4, Numerical Simulation Result and Discussions**, it describes all results and explains the reason of getting the results by using the supported research study. From this part, we will get the answers in detail of our objectives in this study based on this input data. The discussions help us to get clearly understanding of the phenomenon resulting. Then, **Chapter 5 Overall Discussions** summarizes the discussion from each simulation study to provide the overall picture of results directly answer to our objectives. At the end, **Chapter 6 Conclusions and Recommendations**, finally, in chapter 6, we provide conclusions of the thesis and recommendations for future work, which could be used to improve in this study or the relevant researches.

Chapter 2

Literature Reviews

2.1 Literature Reviews of Low Salinity Water Flooding

After the natural depletion of the reservoir, water injection is the most common improved oil recovery (IOR) method. In general, the produced formation water is considered to be injected back to reservoir for displacing oil and maintaining pressure in the reservoir. However, laboratory tests and field applications have shown that low salinity water flooding (LSW) can lead to significant reduction of residual oil saturation. Moreover, there has been a growing interest with an increasing number of LSW studies.

LSW was firstly interested when Reiter (1961) discovered an increased oil production from manipulating the salinity of injected water. Then, Bernard (1967) showed the increasing oil recovery from his experiment, which he reduced salinity from 15,000 ppm to 100 ppm in his injection brine. After that, researchers began to focus on the injection brine salinity, until Tang and Morrow (1999a) offered the first theoretical interpretation of the mechanism responsible by a great number of laboratory tests (Tang and Morrow, 1999a; Tang and Morrow, 1999b; Zhang et al., 2006; Zhang et al., 2007).

Apart from the increasing amount of laboratory experiments were published in the last decade, several field trials have been carried out to test the potential of LSW for improving oil recovery at the field scale. The log-inject-log test (Webb et al., 2003) examined 25-50 % reduction in residual oil saturation when applying LSW. The single well chemical tracer test (SWCTT) performed in Alaska from McGuire et al. (2005) showed a substantial reduction of residual oil saturation after LSW that ranged from 6 to 12 % of original oil in place (OOIP). Robertson (2007) reported that oil recovery tended to increase as the salinity of injection brine decreased in his field evidences in the Powder River basin of Wyoming. In addition, Lager et al. (2008) observed an increase of oil production from 150 bbl. /d to 300 bbl. /d and a decrease in water cut from 92% to 87% in the North Slope of Alaska. The residual oil saturation also decreased from 30% to 20% after LSW. Particularly, Jerauld et al (2008) proposed from his core flooding that the level of incremental oil recovery did not depend simply proportional on the salinity of the brine. The tests had shown that above a certain threshold, recovery did not depend on salinity, and likewise, below a certain level of salinity, there was little dependence; thus only where these thresholds occurred that depended to some degree on the system used. They suggested the threshold range between 1000 – 7000 ppm as shown in Figure 2.5. Webb et al. (2005) showed reservoir conditions core flooding that demonstrate that a reduction to 20% of seawater salinity (i.e. down to 5,600 ppm) gave a small improvement, whereas reducing the salinity to 5%, or by 1,400 ppm, gave a substantial improvement and that much of the benefit is delayed water breakthrough. At last, Morrow et al. (1998) reported that for Dagang crude in Berea core, a reduction to 10% of the connate level, or by 2,417ppm, gave a substantial increase in oil recovery, whereas a reduction to 1%, or by 242 ppm, gave little further increase in recovery. However, Skrettingland (2010) proved the deficiency of low salinity water in certain cases from his core flooding experiments and SWCTT field pilot in the North Sea.

The certain mechanisms that work to enhance oil recovery have not been published yet. Therefore, clear understanding of the mechanisms of LSW would help in describing the recovery process and identifying the optimum salinity and conditions. Some mechanisms behind LSW have been reported and summed up in the following.

2.1.1 Mechanisms of low salinity water flooding

Despite growing interest in LSW, a consistent mechanistic explanation has not yet been emerged. The complexity of the minerals, crude oils, and aqueous-phase compositions and the interactions among all these phases also may contribute to confusion about the cause of LSW. The variety of circumstances under which LSW may or may not be observed suggests that more than one mechanism may be in play. This section is summarized and discussed several mechanisms proposed in the literature regarding LSW.

The possible mechanisms for LSW to improve oil recovery could be attributed to: (1) fine migration or permeability reduction (Morrow et al., 1998); (2) the pH effect (McGuire et al, 2005,); (3) multiple-component ion exchange (MIE) between clay mineral surfaces and the injected brine (Larger et al, 2006). (4) Wettability modification as a result of clay migration and double layer expansion (Tang and Morrow, 1999; Lighthelm et al., 2009).

1) Fine migration or permeability reduction

In situations when fines were mobilized, the recovery benefit upon injecting lower-salinity brine appeared to increase with the abundance of some clay and other minerals, and consequently, variations in lithology were important factor. The Berea sandstone used by Morrow et al. (1998) for many of their experiments had predominantly kaolinite clay and quartz. Increase in oil recovery with increasing kaolinite content was found from a series of SWCTTs. A number of studies had shown that kaolinite was wetted by crude oil (Sincock and Black 1988; Sutanto et al. 1990; Fassi-Fihri et al. 1995; Rueslåtten et al. 1994; Jerauld and Rathmell 1997). The components of crude oil were thought to be ionically adsorbed, particularly to clays because they had a large surface area. Morrow et al. (1998) have found that varying the ionic content of both the injected and connate brine affects oil recovery, thus it is clear that details of the brine chemistry are important. In some experiments, chasing with brines that were richer in divalent had led to an apparent stop in oil production.

Kia et al. (1987) reported that freshwater flooding of sandstones previously exposed to sodium salt solutions resulted in the release of clay particles and a drastic reduction in permeability. The permeability reduction was lessened, however, when calcium ions were also present in the salt solution. Formation damage was virtually eliminated when the solution composition was adjusted to give calcium surface coverage greater than a critical value of 75%, or when a solution Ca2+ fraction is greater than 20 to 30%. Moreover, Khilar and Fogler (1987) results showed a 30% reduction in permeability when the pretreatment was carried out with cesium-salt solutions, a reduction of more than 95% with a sodium-salt pretreatment, and virtually no reduction when the divalent cation existed in the solution. Tang and Morrow (1999a) concluded that fine mobilization (mainly kaolinite) can increased recovery in case of unfired Berea core, whereas fired/acidized core showed insensitivity of salinity on oil recovery. Also, in clean sandstones, the increase in oil recovery with the decrease in salinity was less than that for the clay sands. They also proposed a mechanism of fine migration during LSW that migration of released clay particles which plugged the pore throats was the reason for the increased oil recovery observed during LSW.

On the other hand, Zhang et al. (2007) showed no evidence of clay content in the production stream or the oil/brine interface in their experiments. Lager et al. (2006) and Berg et al. (2009) proposed that this assumption is not the main cause and no fines migration was observed during increased oil recovery in their experiments, thus concluding that no fines migration had occurred, meaning that the enhanced recovery from LSW is not because of fines migration. Besides, Cissokho’s (2009) experimental findings concluded substantial LSW incremental recovery in kaolinite-free cores.

However, the principle that Sheng J.J. (2011) proposed is still supported by many researchers. When clay contacts with fresh water or in water containing insufficient amounts of salt, it tends to hydrate and swell, then affects to dispersion of clay and silt in the formation. The clay and silt become mobile and follow the paths taken by the greatest proportion of the flowing water. These paths are the domains of high permeability, and the mobile clay and silt become lodged in the smaller pore spaces of these domains and reduce the flow of water through these pore spaces. The permeability of the domains where clay and silt lodge is accordingly reduced, and the water is forced to take other flow paths. As a result, reduction in permeability in the more permeable domains improves the mobility efficiency as mobility ratio of waterflood decrease. Premature breakthrough is thus reduced, and the efficiency of the waterflood is improved (Boston et al., 1969).

2) pH Effect

Relationship of pH and salinity was explained by Austad et al. (2010). At reservoir conditions, the pH of formation water is about 5 due to dissolved acidic gases like CO_2 and H_2S. At this pH, the clay minerals, which act as cation exchange material, are adsorbed by acidic and protonated basic components from the crude oil, and cations, especially divalent cations from the formation water, like Ca^{2+}. Injection of LSW, which promotes desorption of Ca^{2+}, will create a local increase in pH close to the brine-clay interface because Ca^{2+} is substituted by H^+ from the water. A fast reaction between OH^- and the adsorbed acidic and protonated basic material will cause desorption of organic material from the clay. So, the increased oil recovery is observed.

Another point is suggested by McGuire et al. (2005) that the dominant low-salinity mechanism, rather than a shift in wettability, was an increase in pH leading to in-situ formation of surfactants through reactions with oil acid components, and that the key effect therefore was a lowering of oil/water interfacial tension (IFT) as seen in alkaline flooding. They did a LSW experiment using core from a North Slope Alaskan field. From initially salinity of 15.000ppm, the pH increased from 8 to 10 when low salinity brine with a salinity of 150ppm was injected and oil recovery increased from 56% to 73%. He proposed that as low salinity water is injected into the core, hydroxyl ions are generated through reactions with the clay minerals present in the reservoir.

However, Valdya and Fogler (1992) studies showed that dispersion of clays is minimized at low pH. Salinity reduction induces a pH increase, which amplifies the release of fines and leads to a drastic reduction in permeability. They reported little change in permeability when fluids with increasing pH were injected until an injection pH of 9 was reached. At a pH > 11, a rapid and drastic decrease in the permeability was observed; yet, at typical low-salinity flooding, pH is lower than 9. In alkaline flooding, pH is usually 11 to 13. Lager et al. (2006) claimed that incremental recovery from LSW effect can be observed during the pH less than 7 condition.

3) Multiple-component ion exchange (MIE) between clay mineral surfaces and the injected brine

This mechanism is based on based on the concept that multivalent cations bridge the negatively charged oil to the clay minerals. In the context of LSW, Lager et al. (2006) suggested multi-component ionic exchange (MIE) resulted in oil desorption when low electrolyte water was used for water flooding, especially Mg^{2+} exchange, which was confirmed by decreasing of the magnesium content in the produced water (Lager et al., 2008).

Moreover, Lager et al. (2006) conducted the experiments with the North Slope core sample at 25C and reservoir temperature 102C. The first core gave recovery 42% OOIP after conventional high salinity water flooding and 48% OOIP after LSW. The second core resulted 35% OOIP by conventional high salinity flooding. Then, this core was flushed with the brine containing only high-salinity NaCl until Ca^{2+} and Mg^{2+} was effectively eluted from the pore surface. The initial water saturation was reestablished, and the sample was aged in the crude oil. Then, the flooding by high salinity water consisting only NaCl was done again resulted in a recovery of 48% OOIP and followed by LSW with again no Ca^{2+} and Mg^{2+} . The final result showed no additional recovery from LSW observed from the only NaCl system. These experiments indicated that LSW affected higher oil recovery in the first core that contained Ca^{2+} and Mg^{2+} (from 42% to 48%) but didn't affect to the core without Ca^{2+} and Mg^{2+} on the surface.

They proposed theory that because of the different affinities of ions on rock surfaces, the result of MIE is to have multivalent or divalent such as Ca^{2+} and Mg^{2+} strongly adsorbed on rock surfaces until the rock is fully saturated. Multivalent cations at clay surfaces are bonded to polar compounds present in the oil phase (resin and asphaltene) forming organo-metallic complexes and promoting oil-wetness on rock surfaces. Meanwhile, some organic polar compounds are adsorbed directly to the mineral surface, displacing the most labile cations present at the clay surface and enhancing the oil-wetness of the clay surface. During the injection of low-salinity brine, MIE will take place, removing organic polar compounds and organo-metallic complexes from the surface and replacing them with uncomplexed. In theory, desorption of polar compounds from the clay surface should lead to a more water-wet surface, resulting in an increase in oil recovery. According to the Deryaguin-Landau-Verwey-Overbeek theory (DLVO theory) (Amarson et al., 2000) there are 4 effective mechanisms possible during MIE: cation exchange, ligand bonding, water bridging and cation bridging, see Figure 2.1.

When the core was fired and acidized, the cation exchange capacity of the clay minerals was destroyed and ,therefore, LSW did not affect to the fired or acidized core. This explains also why low-salinity water injection has little effect on mineral oil, as reported by Zhang et al. (2007), because no polar compounds are present to strongly interact with the clay minerals.

However, Austad et al. (2010) suggested that the polar oil components were initially bound directly to the clay surfaces rather than through a divalent cation bridge. Thus, polar oil components also can adsorb onto clay minerals without bridging divalent cations, and a reduction in magnesium content can be caused by precipitation, such as $Mg(OH)_2$, especially at increased pH levels during LSW.

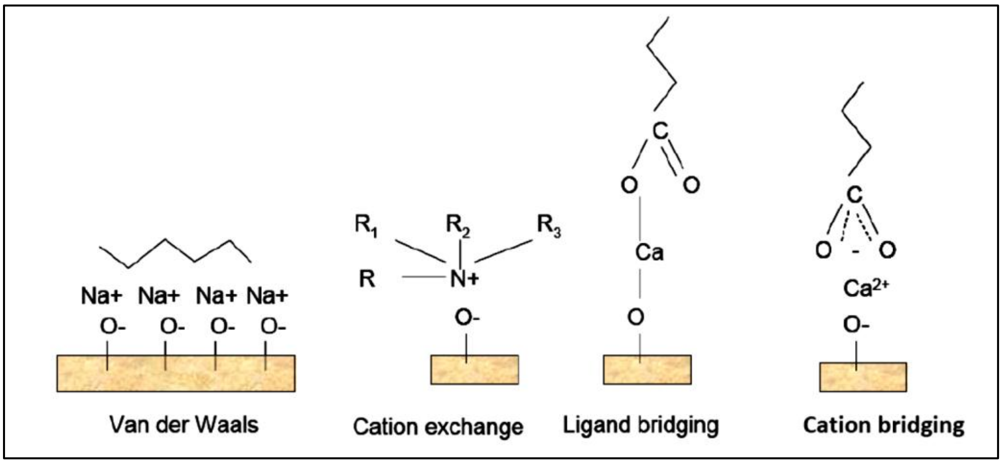


Figure 2.1 Representation of the diverse adhesion mechanism occurring between clay surface and crude oil (Lager et al., 2006)

4) Wettability modification as a result of clay migration and double layer expansion

Results of the work of Tang and Morrow (1997) suggested that additional oil recovery from LSW process is a result of a wettability change toward water-wet, corresponding to greater rates of spontaneous imbibition of brine. This is also indicated by the direction of change of the relative permeability, in that there is a lower water relative permeability and a higher oil relative permeability at a given water saturation. While residual-oil saturation is lower, water relative permeability at residual-oil saturation is roughly the same.

Moreover, Tang and Morrow (1999) proposed that mobilization of oil-wet particles, resulting in exposure of underlying water-wet surfaces, was known to be the major cause of wettability alteration toward decreased water-wetness. It was suggested by Sarkar and Sharma (1990) that limited release of mixed-wet fine particles, probably kaolinite, with associated change toward water-wetness, was responsible for LSW. Exposure to crude oil has been shown to limit the rate of kaolinite-particle release from Berea sandstone, thus limiting the amount of formation damage that might be observed under strongly water-wet conditions. Changes, if any, in pressure drop associated with LSW usually are modest and transient. There are numerous examples of LSW for which production of fine particles is not observed. However, the number of submicron-sized particles in sandstone that change location during LSW has been demonstrated to increase with a decrease in salinity.

In 2009, Lighthelm et al (2009) proposed that wettability modification toward water-wet is the main mechanism from LSW but from the expansion of electrical double layers because this mechanism led wettability becomes more water wet system. Knott (2009) also explained the theory about double layer expansion mechanism in Figure.6. When a negative charged clay particle in the porous rock structure of an oil-bearing reservoir was immersed in water, an electrical double layer was formed around it. The double layers consisted of an inner adsorbed layer of positive ions, and an outer diffuse layer of mainly negative ions. The thickness of the double layers depended on the ion concentration in the surrounding water. In the case of high salinity water containing more ions, the double layer is more compact but when the low salinity water is introduced, the double layer tend to expands as seen in Figure 2.2(1), 2.2(2)., respectively. The adsorbed layer of positive ions contains divalent calcium (Ca^{2+}) or magnesium (Mg^{2+}) ions, which acts as tethers between the clay and oil droplets. Injecting reduced salinity water opens up the diffuse layer, enabling monovalent ions such as sodium (Na^{+}), carried in the injection water, to penetrate into the double layer, Figure 2.2(3) Here, the monovalent ions displace the divalent ions as results to increase electrostatic repulsion between clay particles and oil. It is believed that once the repulsive forces exceed the binding forces via multivalent cation bridge, the tethers between oil and clay particles is broken and the oil particles may be desorbed from clay surfaces. Thus, this will change the wetting state because of the reduction of the rock surface which is coated by oil and allow the oil to be swept out of the reservoir in Figure.2.2(4)

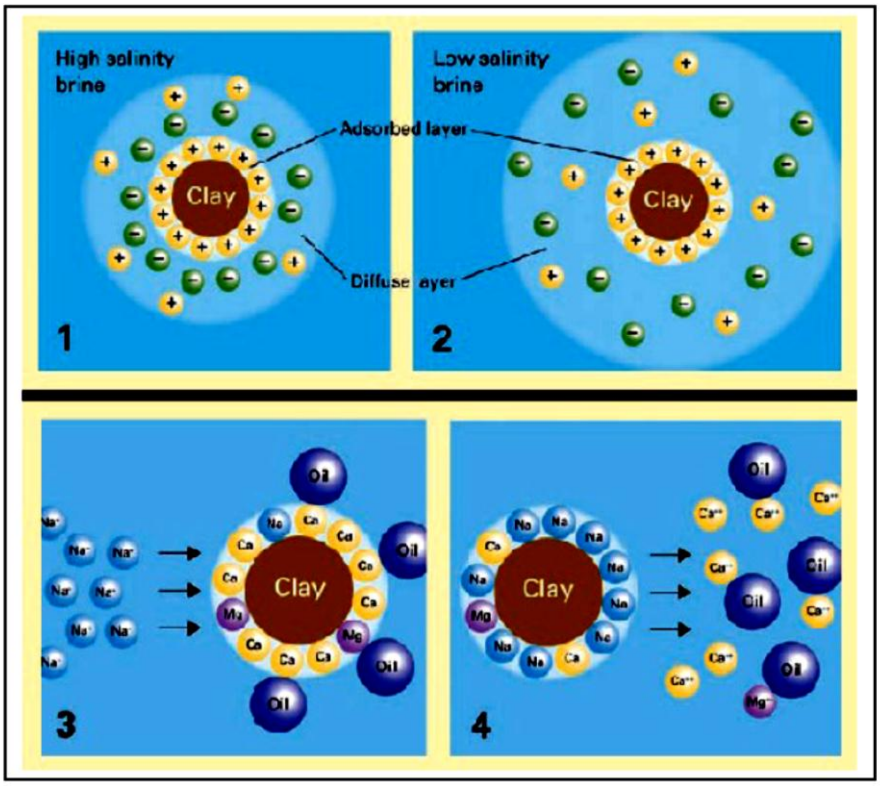


Figure 2.2 How double layer worked (After Knott et al., 2009)

In term of effect of wettability on residual oil saturation, regardless it is the result of clay migration or double layer expansion, Hirasaki et al. (2004) supported the positive relationship between water-wet condition and residual oil saturation by his experiment. They proposed that wetting phase has more tendencies to be in contact with the rock surface. Then, the wetting phase will distribute into small pores and as a thin film on the surface of bigger pores. This makes the wetting phase less mobile than the non-wetting phase which distributes in the large pores, due to higher capillary forces. Herthone (2011a) showed that in oil-wet state, oil adheres to sand or rock and water can move easier. After LSW process, rock turns to water-wet state. Water becomes more in contact with rock and oil is released to be free oil that is movable. Therefore, changing wettability is one strategy to decrease residue oil saturation in the reservoir. The interfacial characteristics of water-oil-rock are shown in Figure 2.3.

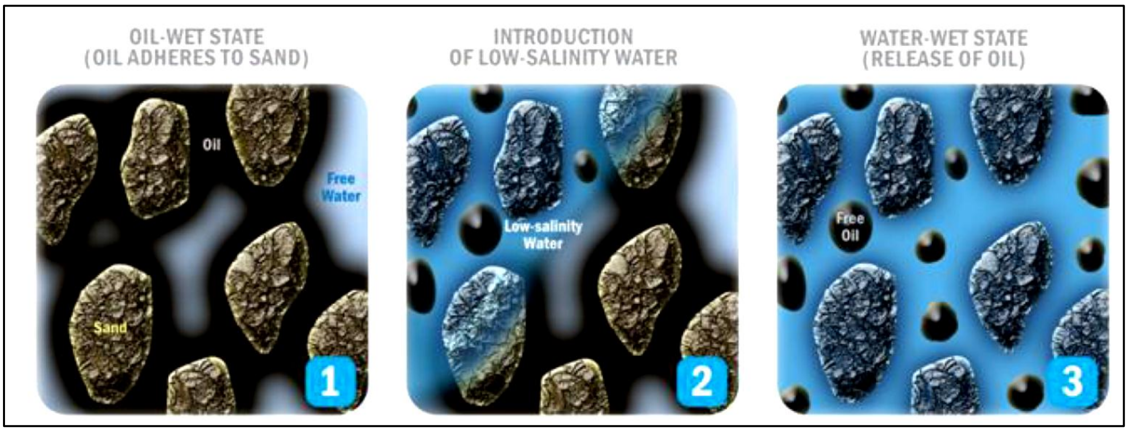


Figure 2.3 Water-Oil-Rock interfacial characteristics (Henthorne L., 2011)

For the LSW in field scale test, in the Omar field in Syria, an evidence of wettability alteration due to LS water injection over a period of 10 years (1992-2002) was recently presented in Vledder et al (2010). The work used a combination of SCAL, NMR, imbibition and open-hole log data around producers at virgin, intermediate and final conditions, and suggested that wettability alteration from the initial oil-wet state to a rather water-wet state may have occurred. From the changes in the remaining oil saturation between these conditions, an incremental recovery of 10-15% of Stock Tank Oil Initially in Place STOIIP was estimated using an analytical assessment.

The amount of salinity composed in LSW was also important to be considered. In virtually all cases tested, substantial low-salinity effects have been seen for salinities in the approximate range of 1,000 to 5,000 ppm, so in most cases, this range can be called as threshold salinity range. Tang and Morrow (1999) showed examples that had an increase in recovery when the salinity of the connate and injected brine was reduced from 15,000 to 1,500 ppm and then a further increase when the salinity was further reduced to 150 ppm. Webb et al. (2005) showed a coreflood where there was no production benefit between the formation water at 80,000 ppm salinity and seawater at 30,000 ppm, but a huge benefit at 1,000 ppm. Figure 2.4 shows reservoir-conditions corefloods that demonstrate that a reduction to 20% of seawater salinity (i.e., down to 5,600 ppm) gave a small improvement, whereas reducing the salinity to 5%, or by 1,400 ppm, gave a substantial improvement and that much of the benefit is delayed water breakthrough.

Lastly, a SWCTT was run in Prudhoe Bay, Well N-01A, which started with a salinity of 23,000 ppm, found no benefit at 7,000 ppm, and found a 4%-PV response at 1,700 ppm (McGuire et al. 2005). There are fewer data available for the value of a low-salinity threshold. Morrow et al. (1998) reported that for Dagang crude in Berea core, a reduction to 10% of the connate level, or by 2,417 ppm, gave a substantial increase in oil recovery, whereas decreasing to 1%, or by 242 ppm, gave little further increase in recovery. Jerauld et al (2006) did LSW test in one dimensional model using salinity dependent oil/water relative permeability functions, resulting from wettability by different karorite content. The input data was based on their laboratory, which salinity dependence was in range of 1000 – 7000 ppm represented low and high salinity, respectively as shown in Figure 2.5.

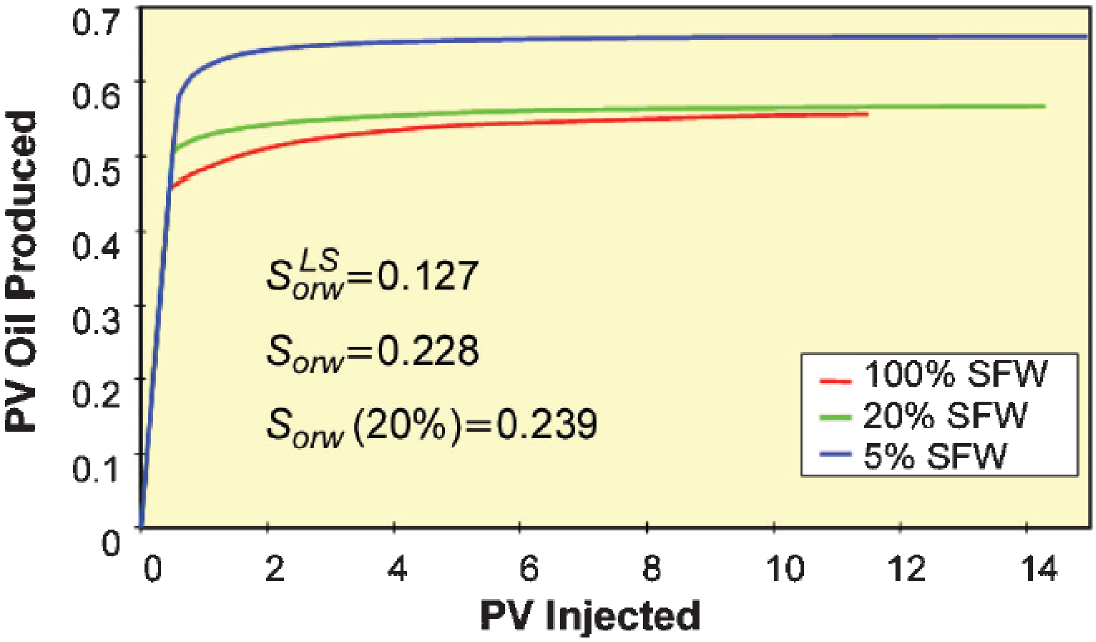


Figure 2.4 dependence of coreflood oil recovery on salinity in secondary low salinity water flooding (SFW=salinity) (Webb et al., 2005)

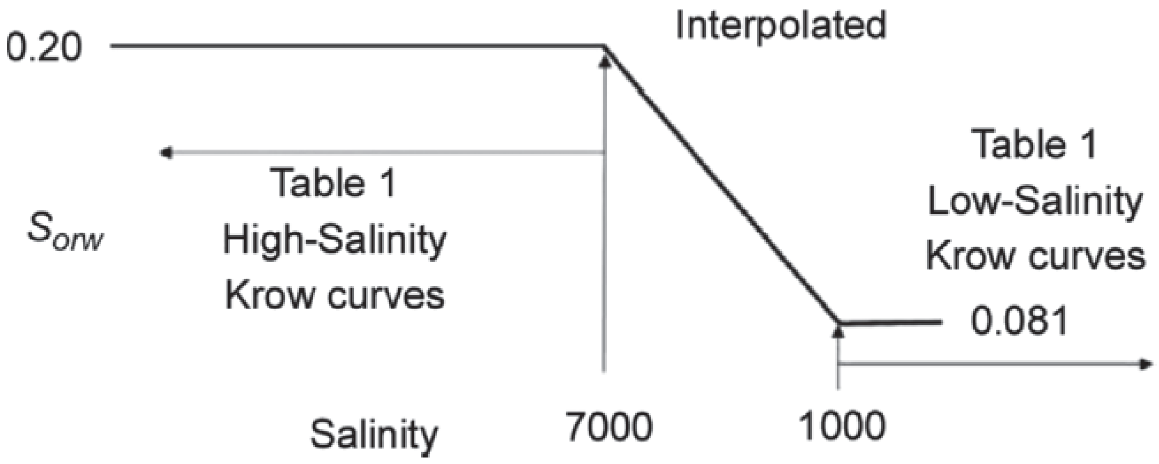


Figure 2.5 Schematic of salinity dependence of residual-oil saturation used in the model (Jerauld et al., 2008)

2.1.2 Summary

Based on the literature review conducted, further wettability alteration, usually toward increased water-wetness during LSW, is the most frequently suggested cause of increased recovery. Note that establishing mixed-wettability by exposure to water and crude oil was a necessary condition for LSW. It has been postulated that when wettability changes from less to more water-wet conditions, oil is released from rock surfaces and recovery is increased. Although the reason supported why exactly the wettability change is not insisted, evidence is often from changes in relative permeability curves or centrifuge capillary pressures. In view of this, the wettability change will be the main consideration applied to chemical flooding for further improvement in oil recovery and the change of relative permeability curve will be used as the input data in simulation. In the next sections, the details of the chemical flooding will be discussed. .

2.2 Literature Reviews of Surfactant Flooding

Surfactant means a blend of surface acting agents. Surfactant is usually organic compounds that are composes of amphiphilic part and hydrophilic part in the same molecule. The term amphiphilic group is a hydrocarbon chain that acts as hydrophobic group (the "tail") while hydrophilic group is the polar part (the "head"). Therefore, surfactant can be soluble in both organic solvents and water. It may be classified according to the ionic nature of the head group as anionic, cationic, nonionic, and zwitterionic (Ottewill, 1984). Anionic surfactant is most widely used in surfactant flooding because it is adsorbed on sandstone rocks, whose surface charge is negative, relative low. In the other way, cationic surfactant can be strongly adsorbed in sandstone rocks, so it is generally not used in sandstone reservoirs but it can be used in carbonate rocks to change wettability from oil-wet to water-wet. Nonionic surfactant primarily used as cosurfactant in system phase behavior. Nonionic is more tolerant of high salinity but its function to improve oil recovery is not as good as anionic surfactant. Zwitterionic surfactant contains two active groups together that are nonionic-anionic, nonionic-cationic, or anionic-cationic. Some surfactant is more tolerant to temperature and salinity but it is expensive. Sometimes surfactant is grouped into low-molecular and high-molecular according to their weight (Lake, 1989).

Enhanced oil recovery (EOR) by surfactant flooding has become more attractive in recent years. In surfactant flooding, surfactant molecules act on the oil/water interfaces. They are used either for wettability alteration or for lowering the oil/water interfacial tension (IFT). In the latter case, the molecules adsorb on the oil/water interface and reduce the IFT and capillary pressure responsible for the trapped oil in the pores. Low interfacial tension at low surfactant concentrations, and acceptable adsorption levels are considered to be important design parameters in optimizing chemical systems for recovering trapped oil from petroleum reservoirs (Adibhatla et al., 2008; Akin and Kovscek, 2003). Ultra-low interfacial tensions of less than 10^{-3} mN/m have been reported with less than 0.1 wt% surfactant concentration measured by the traditional spinning drop method (Swennen et al., 2008) However, interfacial tension can be very difficult to accurately extrapolate from laboratory conditions to reservoir-like conditions. In a surfactant flood, the best surfactant performance depends on the characteristics of crude oil and brine, reservoir conditions, and several other stringent requirements, such as low retention, compatibility, and thermal and aqueous stability (Dogru A.H., 2008)

Several investigations (Hussain etal., 1997; Reed et al., 1977; Wassan and Mohan, 1977) reported that an IFT might be quite different for the same surfactant system but a different phase. A successful surfactant flood should maintain sufficiently low IFT to move the trapped oil, and should maintain the integrity of the surfactant slug during displacement through the reservoir. Factors — such as the minimum dynamic IFT, the equilibrium IFT, the time needed to reach minimum dynamic IFT, and the length of time that the ultra-low dynamic IFT is maintained — are basic parameters in the study of oil–water interfacial tensions (Zhao et al., 2006). It is clear that if we can understand the impact of interfacial tension behavior on the formation and movement of an oil bank, we can take advantage of these factors to develop more cost-effective chemical flood technologies.

2.2.1 Mechanisms of surfactant flooding

Investigating characters of surfactant molecule on oil/water contact and the force on resident oil after water flooding, the effects of surfactant on the resident oil have been studied. In the process of surfactant flooding, surfactant is absorbed on the oil/water contact and the rock surface, so that to change the interfacial tension and invoke resident oil, improving the flow capacity of the mixture. Several surfactant flooding mechanisms in order to improve oil recovery are as follows.

1) Mechanism of reducing the O-W interfacial tension

After a reservoir is water-flooded, globules of oil are left trapped in the reservoir due to a high capillary pressure. When surfactant is injected into the oil layer, surfactant is adsorbed on or concentrated at a surface or fluid/fluid interface. Then, capillary number, which is a dimensionless ratio of viscous-to-local capillary force, is increased. Increase of capillary number in which to decrease IFT makes the discontinuous residual oil globules trapped in the pores of the rock by capillary forces to flow, however, the surfactant should be able to develop low interfacial tension to give a capillary number that is large enough to overcome capillary forces and allow the oil to flow (Emegwalu, C.C., 2009).

The surfactant concentration is an important factor. As describing above, when anionic surfactant is dissolved in aqueous solution, the surfactant dissociates into a cation and a monomer. If the surfactant concentration is increased, the lipophilic halves of the surfactant begin to associate among themselves to form aggregates or micelles containing so many monomers. A plot of surfactant monomer concentration versus total surfactant concentration is a curve at begins at the origin, increasing monotonically, and then levels off at the critical micelle concentration (CMC) as shown in Figure.2.6. (Lake, 1989). It can be indicated that below the CMC, the IFT decreases extensively with the concentration of the surfactant but after a certain concentration, which is above CMC, IFT stays steady or slightly increases with the concentration.

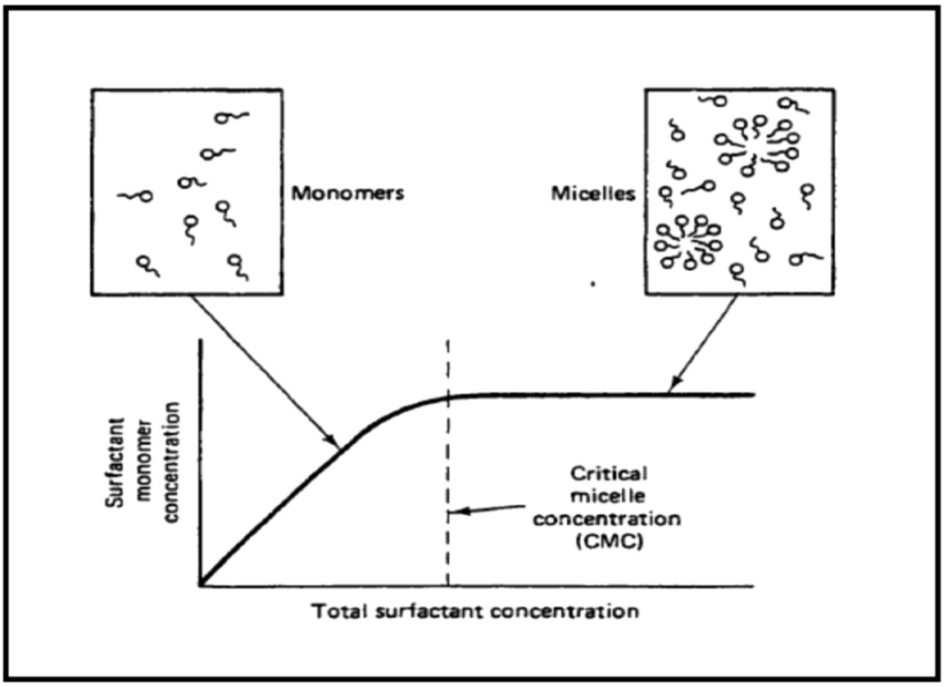


Figure 2.6 The critical micelle concentration (CMC) (Lake, 1989).

The capillary number is usually 10^{-9}~10^{-7} in water flooding. In the ideal state, when it is 10^{-3}, oil recovery can be 100%. The O-W interfacial tension is usually 20~50 mN/m, ideal surfactant can decrease to 10^{-2}~10^{-3} mN/m, so as to decrease or eliminate the capillary action, to decrease the work of adhesion to scale off the resident oil.

Surfactant EOR mechanism is to decrease the O-W interfacial tension. We know that decreasing the O-W interfacial tension will increase the capillary number. The corresponding relative permeability curve is used for various capillary numbers. For high capillary number, the flow is likely monophasic flow and the relative permeability curve. For low capillary number, the relative permeability curve is the laboratory curve. For the capillary number between low and high one, interpolation is used to deal with the relative permeability curve. Large numbers of experiments demonstrated that high capillary number about 10^{-3} can improve recovery greatly, and if capillary number is lower than $10^{-5.5}$, it would not improve recovery (Delshad et al., 1985).

2) Emulsification Mechanism

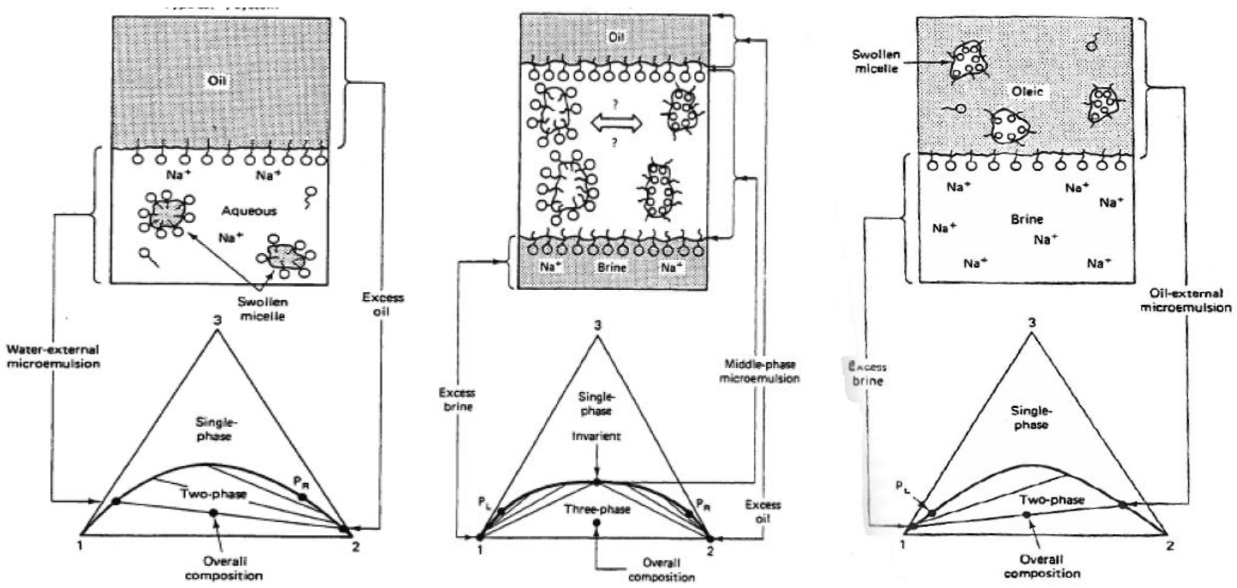
Surfactant system is highly emulsified to oil. When shearing in two-phase flow, it can disperse and scale off oil from rock surface rapidly, forming oil in water emulsion, thereby improving mobility ratio and sweep efficiency. Due to the adsorption of surfactant, oil droplet is electric and difficult to stick on layer, so it can flow to production well with active water (Feng et al., 2011).

3) <u>Wettability reversal mechanism (Oil-wet to Water-wet)</u>

Many experiments showed that the displacement efficiency is closely related to rock wettability. Oil-wetted surface results in the poor displacement efficiency, while water-wetted surface results in good one. The suitable surfactant could increase the contact angle of wettability between crude oil and rock, which could also make rock surface transit from oil wettability to water wettability; thereby it would reduce the work of adhesion of oil droplet in rock surface (Feng et al., 2011).

2.2.3 Effect of salinity in surfactant flooding

Surfactant reduces IFT between oil and water, so that the trapped oil in the reservoir is mobilized. The reduction in interfacial tension produced from a surfactant depends upon a number of factors including; injected surfactant concentration, type of oil in the reservoir, the brine salinity and the amount of surfactant lost to the formation due to adsorption.



Type II (-) **Type III** **Type II (+)**

Figure 2.7 Solubility type of surfactant (Lake, 1989)

In term of brine salinity, as shown in Figure 2.7, at low salinity, which is called “”under-optimum (Type II-)”, the surfactant is predominantly in the aqueous phase, whereas at high salinity, which is “over-optimum (Type II+)”, it partitions preferentially to the oleic phase. At intermediate salinities, an additional phase (often referred to as a microemulsion) may form in the system. This intermediate state with three liquid phases (Type III) results in the lowest IFTs and therefore represents in principle the “optimal salinity” conditions for a surfactant flooding (Hirasaki, J. G, 1980). From Figure 2.8, as salinity increases, Type II- progresses to Type III and to Type II+ phase behavior. The middle-phase composition moves from the brine side of the diagram to the oil side. The surfactant flooding process that exists throughout in the under-optimum salinity, Type II-, is the simplest because the surfactant is normally dissolved in the aqueous phase, so it is transported with the water. In the other side, in over-optimum, Type II+ systems showed the dispersion in that causes finite slug becomes ineffective. Dispersion causes the peak surfactant concentration to decrease, which retards the surfactant because the partition coefficient increases. Therefore, surfactant loses its ability (Hirasaki, 1980). Nelson, R. C. and Pope, G. A. (1978), reported in his experiment later that with a finite slug and the over-optimum salinity environment where only half of oil and very little surfactant were produced.

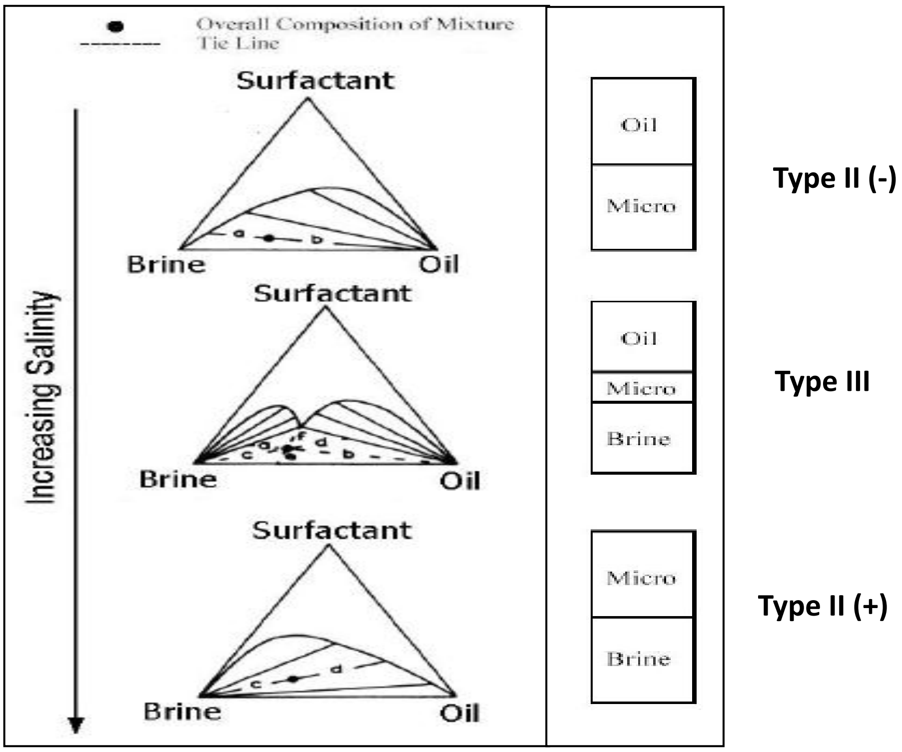


Figure 2.8 Salinity Effects on surfactant phase behavior (Hirasaki, 1980)

Experiments by Glover et al. (1979) for a Type II+ system showed that much of the surfactant retention could be caused by phase trapping whereas much of this retained surfactant could be remobilized with a low-salinity drive. Gupta and Trushenski (1979) showed that, at low salinities relative to optimal salinity, surfactant retention was small but oil recovery was poor when IFT's were too high. At high salinities, recovery was poor because of high surfactant retention. The best recovery occurred at a salinity where IFT was low enough but surfactant retention was not too high. With a salinity contrast they showed that the best recovery took place when the waterflood had high salinity and the drive had low salinity. Over-optimum salinity ahead of the surfactant bank produces a Type II+ system, which retards transport of surfactant. Low salinity in the drive produces Type II- behavior, which causes surfactant to be transported in the aqueous phase.

For the relationship between optimum salinity and surfactant concentration, Nelson (1982) proposed that there are two groups. In one group, the optimum salinity increases with surfactant concentration, whereas in the other group, the optimum salinity decreases with surfactant concentration. Of course, there is another group in which the optimum salinity is independent of surfactant concentration. Hirasaki (1983) pointed out that the change in optimum salinity is a consequence of divalent ions interacting with surfactant or of surfactant "pseudocomponents" partitioning in different proportions. With NaCl brine, the electrolyte was partially excluded from the micelle. However, the opposite trend was observed with $CaCl_2$ brine because of the strong association of anionic surfactant with divalent cations. Therefore, decreasing surfactant concentration reduced interactions between the interfacial region and brine; then optimum salinity decreased. Glover et al. (1979) also discussed that the decreased optimum salinity with decreased surfactant concentration was caused by the exchange of divalent cations with monovalent cations and the existence of cosolvents in the surfactant solution.

2.2.3 Summary

In surfactant flooding, surfactant is absorbed on the oil/water contact and the rock surface, so that capillary number and capillary force increase, which lower IFT and residual oil saturation. Increase of surfactant concentration can strongly affect to lower IFT but after a certain concentration, IFT stays constant. Low salinity brine has a better result to surfactant flooding in order to get higher oil recovery than high salinity brine. However, the intermediate salinity, which forms state of three phases (type III), is the optimal condition because it creates lowest IFT results to highest oil recovery. The relationship between optimum salinity and surfactant concentration was system-dependent. In other words, the optimum salinity could decrease or increase with surfactant concentration, depending on surfactant, cosolvents, salinity, divalent contents, and so on.

2.3 Literature Reviews of Alkaline Flooding

Alkaline flooding, also known as caustic flooding, is an enhanced oil recovery (EOR) technique, in which an alkaline solution, such as sodium hydroxide, sodium orthosilicate, or sodium carbonate, is injected during the water flooding process (Lake, 1989). During the alkaline flooding, organic acids, naturally occurring in some crude oils, will react with alkaline solution to produce soap at the oil/water interface. The soaps, which is in-situ surfactant, formed lower IFT between crude oil and flood water, and under the proper conditions of salinity, pH, and temperature. When the proper alkaline solution and acidic oil flow simultaneously in a porous medium, a viscous oil-external emulsion is formed. The flow properties of this type of emulsion permit a high, non-uniform pressure gradient to be generated across the narrow region in the vicinity of the emulsion front. The pressure gradients are sufficient to overcome the reduced capillary forces and displace the oil from the pore space. The displacement efficiency can be much improved over ordinary waterflood efficiencies. The level of IFT reduction is also dependent on the type and concentration of alkali and on the chemical makeup of the crude oil (Liu Q., 2006)

In term of alkaline concentration, the incremental oil recovery as a function of alkaline concentration due to the interaction between oil and alkaline solution, resulting in the creation of in-situ O/W emulsion (Liu Q., 2006). However, there is an alkaline concentration range in which the IFT between a crude oil and an alkaline solution is the minimum. When the alkaline concentration is out of this range, the IFT increases drastically. Zhao et al. (2002) did experiments observing the dynamic IFT between a crude oil and NaOH solution at different NaOH concentrations and the fixed ionic strength (salinity) at 0.01 mol/L. The results are shown in Figure 2.9. When NaOH concentration is very low (10^{-4} mol/L, Curve 1), the amount of soap generated at the oil/water interface is very small, and the IFT is above 10 mN/m. When NaOH concentration is not very low (5×10^{-4} mol/L, Curve 2), the IFT passes by a low value. As the soap leaves the interface and enters the aqueous phase, the IFT stays at a high value. At some optimum NaOH concentrations (10^{-3} mol/L, Curve 3, and 5×10^{-3} mol/L, Curve 4), the IFT will stay at a low value. At a very high NaOH concentration (10^{-2} mol/L, Curve 5), the soap quickly generates at the interface, and the IFT suddenly becomes low but, as the soap leaves the interface, the IFT becomes high again at the end.

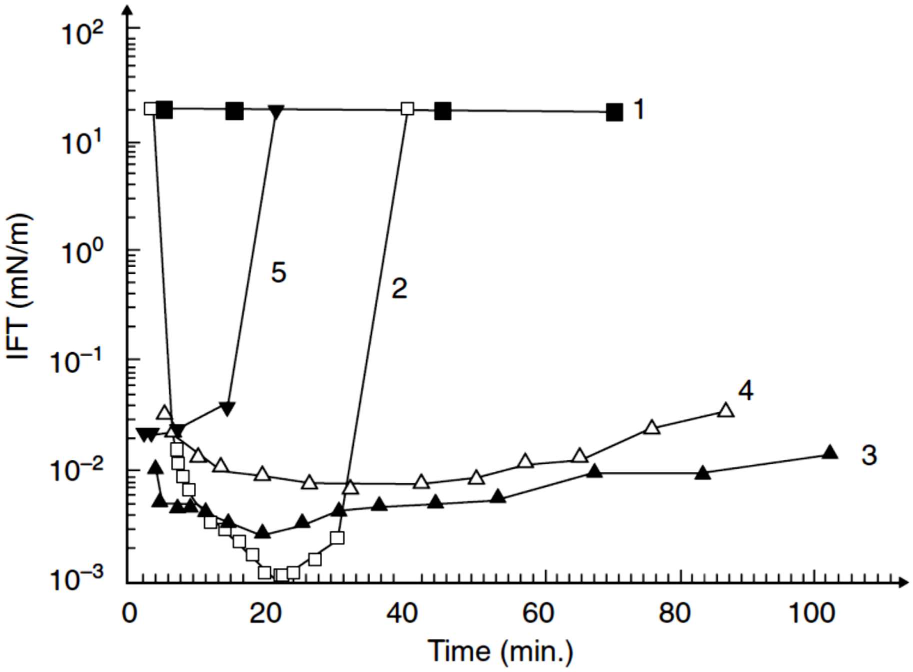


Figure 2.9 Dynamic IFT between a crude oil and NaOH solution at different concentrations with [Na+] = 0.01 mol7L at 30C. NaOH concentration (10-3 mol/L): Curve 1, 0.1; Curve 2, 0.5; Curve 3, 1; Curve 4, 5; Curve 5, 10 (Zhao et al, 2002)

The most important in Alkali/rock reactions aspect is calcium and magnesium ion presented in clays. In addition to ion exchange with rock surfaces, alkali can react directly with specific rock minerals. When divalents, Ca^{2+} and Mg^{2+}, exist, alkali will react with them and precipitation can occur. This is ordinarily accomplished by using a sodium carbonate buffer, which removes calcium as it exchanges off the clay by precipitating it as insoluble calcium carbonate. In doing so, however, carbonate ions, which are the buffering agent in the system when sodium carbonate is used, are also removed. Thus, reaction with calcium on the clays also consumes the alkaline solution as it moves through the reservoir. Interaction of alkali with rock minerals is complicated and can include ion exchange and hydrolysis, congruent and incongruent dissolution reactions, and insoluble salt formation by reaction with hardness ions in the pore fluids and exchanged from the rock surfaces (Sheng J.J., 2011).

2.3.1 Mechanisms of alkaline flooding

Johnson (1976) summarized several proposed mechanisms by which caustic water flooding may improve oil recovery.

1) Emulsification and Entrainment

In emulsification and entrainment, the crude oil is first emulsified in-situ resulting in IFT reduction, and it is entrained by the aqueous alkaline solution flow. These mechanisms occur in high pH, low acid number, low salinity, and Oil/Water emulsion size less than pore throat diameter (Subkow, 1942).

2) Emulsification and Entrapment

In emulsification and entrapment, the crude oil is also emulsified. The oil droplets will block the smaller pore throats; as a result, the sweep efficiency is imposed (Jennings et al., 1974). The conditions for this mechanism to occur are high pH, moderate acid number, low salinity, and O/W emulsion size is bigger than pore throat diameter. This mechanism is especially important in water flooding viscous oils where waterflood sweep efficiency is notoriously poor, but no significant reduction in residual oil is expected with this mechanism (Sheng, 2011).

3) Wettability Reversal (Oil-wet to Water-wet)

When the wettability is changed from oil-wet to water-wet, oil production increases owing to favorable changes in permeability. This mechanism is limited to oil-wet reservoirs where wettability could be reversed from oil-wet to water-wet (Wagner and Leach, 1959). Mungan (1966a) said that alkaline flooding lower the water relative permeability, and later he (1966b) used Teflon cores (preferentially oil-wet material) in his experiments to demonstrate that higher oil recoveries could be achieved by the wettability reversal mechanism.

4) Wettability Reversal (to Water-wet Oil-wet)

In the water-wet to oil-wet type of wettability reversal, low residual oil saturation is attained through low IFT and viscous water-in-oil emulsions working together to result in a high capillary number. Obviously, the salinity in alkaline water should be high so that W/O emulsion can be generated with the help of low IFT caused by soap, and the rock surfaces are made to be oil-wet. The mechanics of the process involves first the conversion of water-wet rock to oil-wet. Here, a discontinuous, non-wetting residual oil is converted to a continuous wetting phase, providing a flow path for what otherwise would be trapped oil. At the same time, low interfacial tension induces formation of an oil-external emulsion of water droplets in the continuous, wetting oil phase. These emulsion droplets tend to block flow and induce a high-pressure gradient in the region where they form. The high-pressure gradient, in turn, is said to overcome the capillary forces already decreased by low interfacial tension, thus reducing residual oil saturation further (Cooke et al., 1974).

However, there have been many proposals indicated that alkaline reacts with naphthenic acid in crude oil to generate soap. The soap, an in-situ generated surfactant, reduces the interfacial tension between the alkaline solution and oil. This is intuitive to infer that the main mechanism in alkaline flooding is low IFT (Fadili A. et al, 2010).

Although the IFT between the solutions and the oil is very necessary in the design of an “enhanced alkaline system”, it is also important that IFT is maintained between the fluids moving and the reservoir rock. Otherwise, the chemical system will be ineffective in displacing sufficient oil process. The chemical makeup of the rock, including clays, and the fluids are used to determine in a particular reservoir. (Sheng J.J., 2011).

Another consideration is mobility control. If the oil mobilized by reducing the IFT is displaced by water alone, the water will probably bypass the oil and leave the mobilized oil in the reservoir. For this reason, it may be necessary to improve displacement efficiency by adding some chemical like polymer (Surkalo H., 1990).

2.3.2 Effect of salinity in alkaline flooding

To evaluate the influence of brine salinity on alkaline flooding, Jijiang et al. (2012) observed that the brine salinity has a significant impact on the emulsion types. Oil in Water (O/W) emulsions tends to be formed when the salinity is low. In contrast, Water in Oil (W/O) emulsions mostly occurs when the mass concentration of NaCl is above 0.7%. Displacement experiments were performed to examine the effect of the brine salinity on alkaline flooding. The results of the tertiary oil recovery are plotted as a function of the brine salinity, as shown in Figure 2.10. It can be observed that the brine salinity indeed has an effect on the displacement efficiency. The incremental oil recovery first increases and subsequently decreases with the brine salinity, suggesting there should be an optimum salinity point.

When brine salinity is low, the in situ surfactants formed by the reaction of the alkaline solution and the crude oil are mainly dispersed in the aqueous phase, which tend to facilitate the formation of O/W emulsion in the phase behavior test. Therefore, the penetration of the alkaline solution into the crude oil may be weakened to some degree. With the increase of the brine salinity, the diffusion of the in situ surfactants into the aqueous phase declines and more surfactants remain at the oil/water interface, which is favorable for the formation of water drops inside the oil phase. However, when the brine salinity is too high, some honeycomb oil blocks appear and the improvement in oil recovery is limited. Therefore, the optimum brine salinity plays a significant role for alkaline flooding.

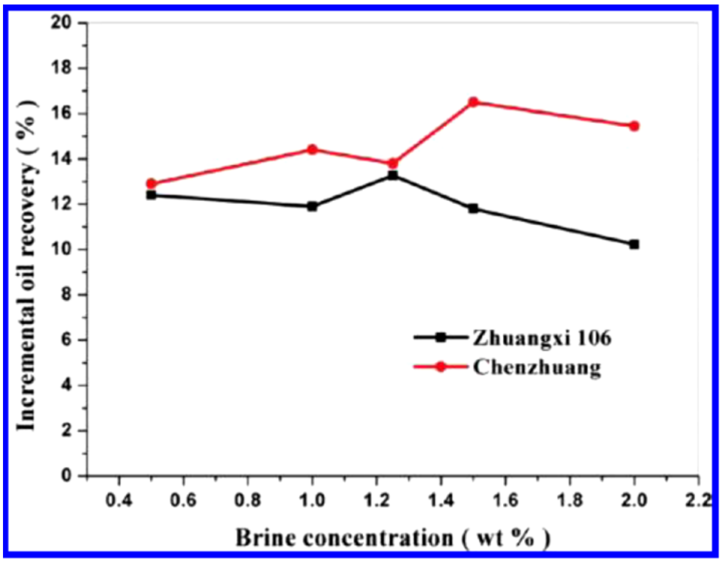


Figure 2.10 Performanace of alkaline flooding at different NaCl concentrations for 2 different crude oils (Jijiang et al. 2012)

2.3.3 Summary

Alkaline reacts with naphthenic acid in crude oil to generate soap. The soap, an in situ generated surfactant, reduces the interfacial tension between the alkaline solution and oil. It is intuitive to infer that the main mechanism in alkaline flooding is low IFT. For reservoirs with oil having high acid numbers, alkaline flooding can be executed at any development stage. However, for reservoirs with oil having low acid numbers, alkaline flooding in an earlier stage performs better. In this case, remaining oil saturation should be higher than 0.4. There is no temperature limitation for alkaline flooding. The incremental oil recovery is a function of alkaline concentration but in range of optimum concentration. The salinity effect depends on the emulsion type of alkaline. However, the too low salinity can make difficulty for alkaline solution to affect with oil and too high salinity can make the oil blocks appear in the flowing path. These mean that, apart from optimum alkaline concentration, optimum salinity is also considered for highest recovery. In addition to ion exchange with rock surfaces, alkaline can react directly with specific rock minerals.

2.4 Literature Reviews of Polymer Flooding

Normally, in order to change displaced oil mobility (relative permeability and/or viscosity) is not often feasible without the injection of heat. However, we can inject some chemicals to change displacing fluid mobility. Primarily, the injected chemicals are polymers whose obvious function is to increase the displacing polymer solution viscosity (Sheng J.J., 2011). Water-soluble polymers for EOR applications have been successfully implemented mainly in Chinese oilfields (Han et al., 1999). The purpose of the water-soluble polymers in this application is to enhance the rheological properties of the displacing fluid. The oil production increases with the microscopic sweep of the reservoir and the displacement efficiency of the oil. Indeed, the use of water-soluble polymers improves the water–oil mobility ratio (Lake, 1989), and leads to enhanced oil recovery. However, given the harsh conditions present in most oil reservoirs, new problems and limitations arise with the use of water-soluble polymers. Besides positively affecting solution rheology, water-soluble polymers should withstand high salt concentration, the presence of calcium, high temperatures (>70 ◦C) and long injection times (at least 12 months) (Lake, 1989). High salt concentrations reduce the thickening capability of most ionic water-soluble polymers while the presence of calcium leads to flocculation. New water-soluble polymers were successfully tested at higher temperatures. Associative water-soluble polymers were tested and showed promising results compared to traditionally used polymers. Several studies demonstrated that the oil is produced faster (compared to water flooding), but also more oil can be recovered (Wever et al., 2011).

Polymers that have been used in actual polymer floods comprise the two general types of synthetic polymers and biopolymers. A synthetic polymer almost always means polyacrylamides (PAM) and hydrolyzed polyacrylamides (HPAM). A variety of these are available from several manufacturers. In general, the performance of a polyacrylamide in a flooding situation will depend on its molecular weight and its degree of hydrolysis. In a partially hydrolyzed polyacrylamide, some of the acrylamide is replaced by, or converted into, acrylic acid. This tends to increase viscosity in fresh water, but to reduce viscosity in hard waters. All else being equal, a high molecular-weight polymer will produce higher viscosities and resistance factors than a low-molecular-weight polymer for a given concentration. These potential advantages may be offset by a greater tendency for shear degradation, which reduces molecular weight, and by a reduced injectivity, which can be significant in low-permeability formations. For large-scale applications, polyacrylamides are available in powder form (90% active), in the form of a pumpable convert to emulsion (33 to 55% active), or can be manufactured on site in a concentrated solution form. It is applicable to light and medium gravity oil fields (Riley B.N. and Peter H.D., 1987).

Biopolymers are derived from a fermentation process, rather than by direct synthesis from their monomers in a chemical reactor. The most commonly encountered biopolymer is xanthan gum, which is produced by the bacterium. However, the synthetic polymer is used more widely than biopolymers due to relatively low price, develop good viscosities in fresh waters, and adsorb on the rock surface to produce a long-lasting permeability reduction (the residual resistance effect). These all advantages can make the primary disadvantages as a tendency to shear degradation at high flow rates and poor performance in high-salinity water regardless (Riley B.N. and Peter H.D., 1987).

2.4.1 Mechanisms of polymer flooding

The reduction of water solution mobility is due to two different factors. First, the viscosity of polymer solution increases as the concentration of polymer in water increases. Second, the relative permeability to oil remains almost unaffected while the rock relative permeability to water is reduced due to the absorption and entrapment of huge macromolecular polymer in the porous media. The combination of these factors reduces the water solution mobility considerably although it maintains the mobility of oil.

One obvious mechanism in polymer flooding is the reduced mobility ratio of displacing fluid to the displaced fluid so that viscous fingering is reduced. When viscous fingering is reduced, the sweep efficiency is improved, as shown in Figure 2.11 and 2.12. An increase in polymer concentration will increase viscosity of solution. This is clearly a mass effect as more polymer molecules are dissolved. However, the increase in viscosity may not be proportional to increase in concentration at low shear rates (Sheng J.J., 2011).

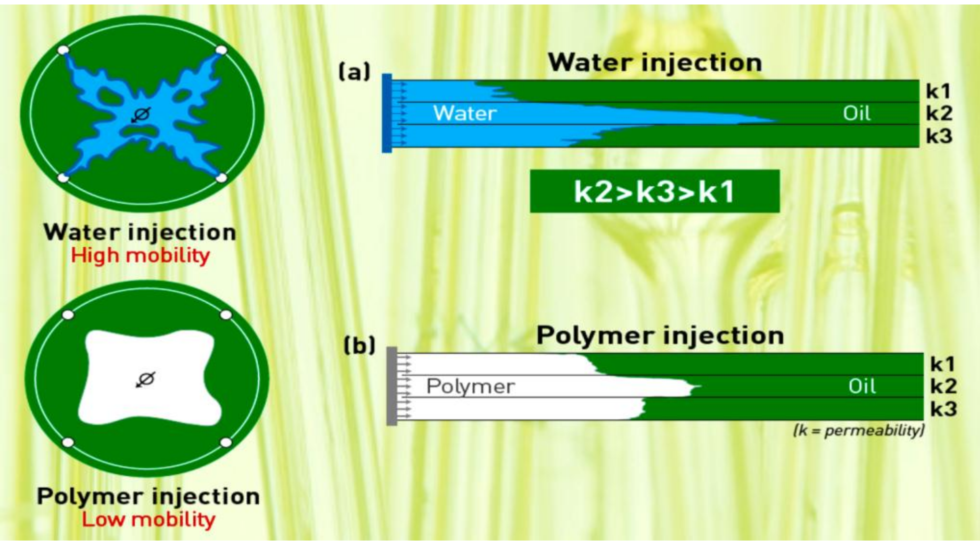


Figure 2.11 The effects of reducing viscous fingering to water/ polymer injection (Total, 2008)

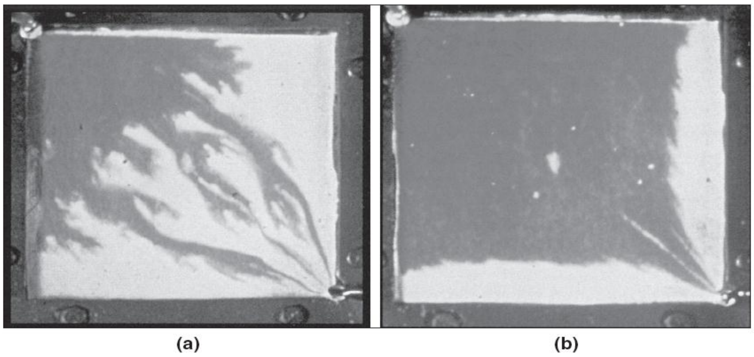


Figure 2.12 Schematic of macroscopic displacement efficiency improvement by polymer flooding (a) water flooding (b) polymer flooding (Sheng J.J., 2011)

Permeability reduction, or pore blocking, is caused by polymer adsorption. Therefore, rock permeability is reduced when a polymer solution is flowing through it, compared with the permeability when water is flowing. Apart from pore blocking by polymer adsorption, polymer is also used to shut off water channeling through high-permeability layers and water conning from bottom aquifers. In these types of applications, the injected polymer volume is needed to be large enough. If it is too small that can be because of high injection pressure constraints or short gelation time, the blocking water channeling or water coning by polymer is only temporary. Eventually, water will bypass the injected polymer zone and cross-flow to high permeability zones or bypass the polymer zone to the producing wellbores. This problem is needed to be avoided by adding a weak gel, which has high resistance to flow but is still able to flow, in the reservoir. Thus, a large volume or large area of polymer zone is formed to block water thief zones or channels. In polymer and gel treatment, another mechanism is called disproportionate permeability reduction (DPR). Through the use of this mechanism, polymer and gel can reduce water permeability much more than oil permeability.

Another mechanism is related to polymer viscoelastic behavior. The interfacial viscosity between polymer and oil is higher than that between oil and water. The shear stress is proportional to the interfacial viscosity. Because of polymer’s viscoelastic properties, there is normal stress between oil and the polymer solution, in addition to shear stress. Thus, polymer exerts a larger pull force on oil droplets or oil films. Oil therefore can be “pushed and pulled” out of dead-end pores. Thus, residual oil saturation is decreased.

Generally, the ultimate incremental oil recovery mainly depends on the total amount of polymer injected. A higher concentration can result in more initial water-cut reduction due to polymer injection. However, a high concentration may be limited by the allowable injection pressure. From a mobility control point of view, a higher concentration should be injected at the front to counteract dilution. A commonly used concentration in China is around 1200 mg/L (Sheng J.J., 2011).

2.4.2 Effect of salinity in polymer flooding

The salinity is of importance in the apparent viscosity since cations screen the negative charges of carboxyl groups along the polymer chain, allowing the chain contraction with the reduction in electrostatic repulsion. It is generally known that the addition of salts significantly reduces viscosity of polymer solution. Tam and Tiu (1990) studied the effect of salts on the steady shear behavior of HPAM, who showed that the addition of divalent salts in solution reduces viscosity at the zero-shear-rate limit by about 5 to 6 times more than the monovalent salts. The addition of salts also shifts the position of the critical shear rate (where the onset of shear-thinning occurs) to a higher value, and reduces the slope of shear thinning region.

Han et al. (1999) observed that in the brine of low to medium salinities (monovalent content), the viscosity of polyacrylamide solution increases as hydrolysis proceeds (increases). However, in the presence of divalents, the viscosity behavior will be determined largely by the divalent metal ion concentrations. As hydrolysis increases, more acrylic acid exists in the solution. Hydrolyzed polyacrylamides (negative carboxyl groups) interact strongly with divalent metal cations such as $Ca^{2+}$and Mg^{2+}. This phenomenon is commonly associated with reduction in solution viscosity, formation of gels or precipitates.

Vermolen et al. (2011) showed the dependency of 1000 ppm solutions of n- Vinyl Pyrrolidone (n-VP) Polymer 3, n-VP Polymer 4 and HPAM polymer viscosity to salinity over a large range of NaCl. Their data plotted in Figure 2.13, where salinity is plotted on a log scale. It can be indicated that there is not much dependency to salinity below salinities of 0.001 g/L (1ppm) and above 10 g/L (10000 ppm) while there is a strong dependence of polymer viscosity on salinity between these thresholds where it can be operated as low salinity floods, and little dependence above seawater salinity.

Levitt et al. (2008) also tested several high molecular weight polymers exhibiting high viscosities at high salinities up to 170,000 ppm NaCl and greater than 17,000 ppm $CaCl_2$. They showed that polyacrylamide polymers hydrolyze at high temperatures and beyond a certain point are subjected to precipitation by calcium. They concluded that if calcium concentration is kept below 200 ppm, the use of polyacrylamide polymers is feasible up to reservoir temperatures of at least 100C. This conclusion makes the combination of low-salinity and polymer flood even more desirable and expands the application of these EOR methods to high-temperature reservoirs.

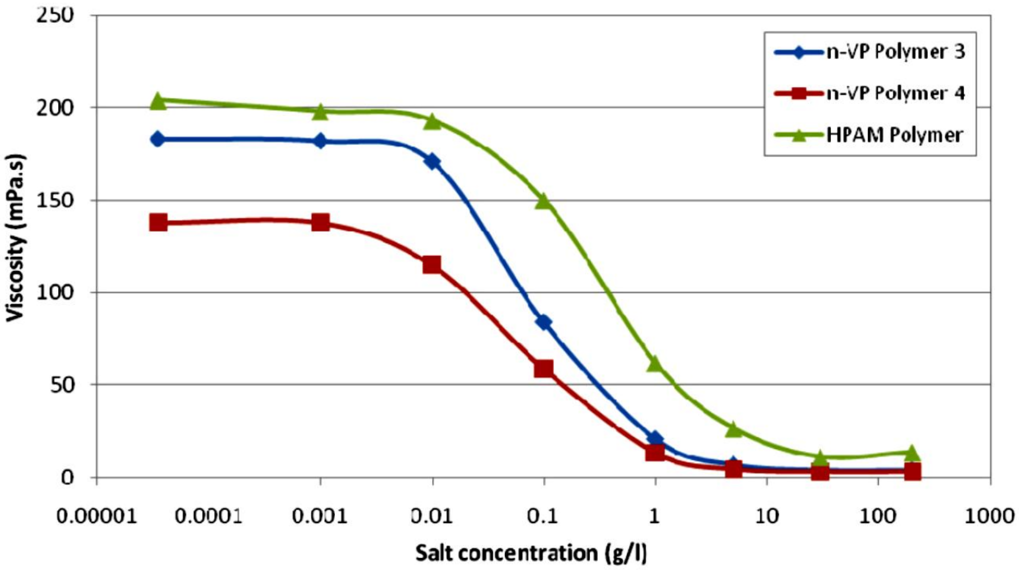


Figure 2.13 Viscosity of two 1000 ppm polymer solutions as a function of the brine salinity (NaCl) at temperature 25 C and a shear rate of 5.68 S^{-1} (Vermolen et al., 2011)

Lee et al. (2009) developed a comprehensive rheological property database for EOR polymers, such as HPAM 3330S, 3630S and AN-125 (AMPS co-polymer). In their study, they measured the dependency of polymer viscosity to NaCl and $CaCl_2$ concentrations. It is observed from their study that reduction of salinity from 4 to 0.1wt% NaCl increases the polymer viscosity from about 20 cP to about 800 cP. Polymer viscosity is also very sensitive to the divalent cation concentration. Viscosities of polysaccharide polymers are relatively insensitive to salinity and hardness.

There is some evidence that low salinity decreases polymer adsorption. Sorbie (1991) stated that increasing NaCl concentration greatly increases the level of HPAM adsorption. Smith (1970) showed the effect of sodium chloride concentration on the adsorption of HPAM polymer onto the silica powder and concluded that low concentrations of divalent calcium ions, Ca^{2+}, are even more effective in promoting HPAM adsorption on silica powder than low concentrations of Na^{+} ions. The retention levels are much lower for sandpacks and sandstone cores. This is attributed to polymer exclusion from much of the pore space, resulting in polymer flow through the larger pores which have the lowest surface area.

2.4.3 Summary

Polymer flooding has the main effect as reduction of water solution mobility due to two factors: the viscosity of polymer solution increases as the concentration of polymer in water increases and the rock relative permeability to water is reduced due to the absorption and entrapment of huge macromolecular polymer in the porous media. In generally, polymer solution viscosity decreases with the presence of NaCl but only in a range of threshold, where there is strong dependence. Not only the low salinity can increase polymer solution viscosity, but it also decreases polymer adsorption on the rock surface.

2.5 Literature Reviews of Alkaline – Surfactant – Polymer Flooding (ASP)

Alkaline-surfactant-polymer flooding (ASP) is the combination of alkaline flooding, surfactant flooding, and polymer flooding (Wang et al. 2007). In the recent years, a great progress has been made either in laboratory studies or in pilot tests (Zhang et al. 2007; Hou et al. 2005; Daoshan et al. 2004). Its displacement mechanisms are consequently the combination of those individual processes. Therefore, oil recovery is enhanced gently by decreasing interfacial tension (IFT), increasing capillary number, enhancing microscopic displacing efficiency, improving mobility ratio and increasing macroscopic sweep efficiency (Shen and Yu 2002). Alkali forms soaps by reacting with naturally occurring organic acid in the crude oil, which interact synergistically with added surfactant to produce ultra-low IFT. The ultra-low IFT is obtained by surfactant distribution between oil and water phase, and surfactant arrangement at interface of oil/water. This is controlled by pH value and ionic strength. The alkali injected with surfactant can also reduce surfactant adsorption, play the role of ionic strength and lower IFT. Addition of polymer increases the viscosity of its aqueous phase, so that the mobility of aqueous phase decreases. Thus, the decrease in mobility ratio greatly increases sweep efficiency. Another main accepted mechanism of mobile residual oil after water flooding is that there must be a rather large viscous force perpendicular to the oil–water interface to push the residual oil. This force must overcome the capillary forces retaining the residual oil, move it, mobilize it, and recover it (Guo and Huang 1990). Wang et al. (2010) studied the viscoelastic effect of retained polymer molecules in porous media based on the pressure draw-down and buildup process. They proposed that the micro-scale displacement efficiency depends on the flow pattern and magnitude of the viscous force parallel to the oil–water interface.

Substantial research works are being carried out worldwide on alkali, surfactant and polymer flooding by different point of views. Hawkins et al. (1994) reported that the simultaneous injection of alkali and polymer is more effective than the same chemicals injected sequentially with no contact between alkali and polymer. Tong et al. (1998) reported that the main mechanisms of ASP flooding are interface producing, bridging between inner-pore and outer-pore and oil–water emulsion. In a vertical heterogeneous reservoir, ASP flooding increases displacing efficiency by displacing residual oil through decreasing IFT and improving sweep efficiency. Moreover, ASP flooding is more effective for oil with high acid value. They showed that flooding system's rheology and IFT between flooding system and oil with high acid value were the key factors effecting oil recovery. Shen et al. (2009) investigated the fluid-flow mechanism of enhanced oil recovery (EOR) in porous media by ASP flooding. They reported that ASP flooding displaces not only the residual oil in the high-permeability layer but also the remaining oil in the low- and middle permeability layers by increasing both swept volume and displacement efficiency

However, in order to study the contributions of each chemical flooding to the ASP flooding, it is better to simplify it into couple of flooding method. Moreover, it is easier to analyze the effect of each-by-each chemical type. Therefore, ASP flooding is divided to alkaline-polymer flooding (AP), alkaline-surfactant flooding (AS) and surfactant-polymer flooding (SP) in the following section.

2.5.1 Alkaline – Polymer flooding (AP)

Many field tests have revealed that alkaline flooding is not a simple method but requires careful project design and monitoring techniques. One reason that the results from conventional alkaline flooding have not been encouraging is that low alkaline concentrations required for obtaining low interfacial tension are not capable of propagating alkaline because of the consumption by ion exchange and dissolution, and precipitation processes. Another reason is the lack of mobility control. Therefore, the combination of alkaline and polymer floods seems to be a better option (Sheng, 2011).

2.5.1.1 Mechanism of AP flooding

1) Alkaline effects on polymer

It has been reported that addition of alkaline into a polymer solution can slightly increase its viscosity (Krumrine and Falcone, 1983). However, the opposite trends are found from Figure 2.14. It shows the effects of alkaline on the viscosity of polymer solutions. It is seen from these curves that the higher the alkaline concentration, the lower the viscosity of a polymer solution. The presence of sodium ions in the polymer solution, which is kind of salt effect, can neutralize these carboxyl groups. Hence, the repulsive forces among carboxyl groups are shielded and the polymer chains are coiled up (Lake, 1986). This shielding effect significantly decreases the viscosity of polymer solution. On the other hand, addition of NaOH helps to increase the hydrolysis of polyacrylamide, which introduces negative charges, i.e., carboxyl groups, on the backbone of polymer chain. These carboxyl groups repel each other and cause the polymer chain to stretch. This process can slightly increase the viscosity of a polymer solution (Green et al., 1998). The concurrence of these two counteracting processes determines the overall effects of alkali on the viscosity of polymer solutions.

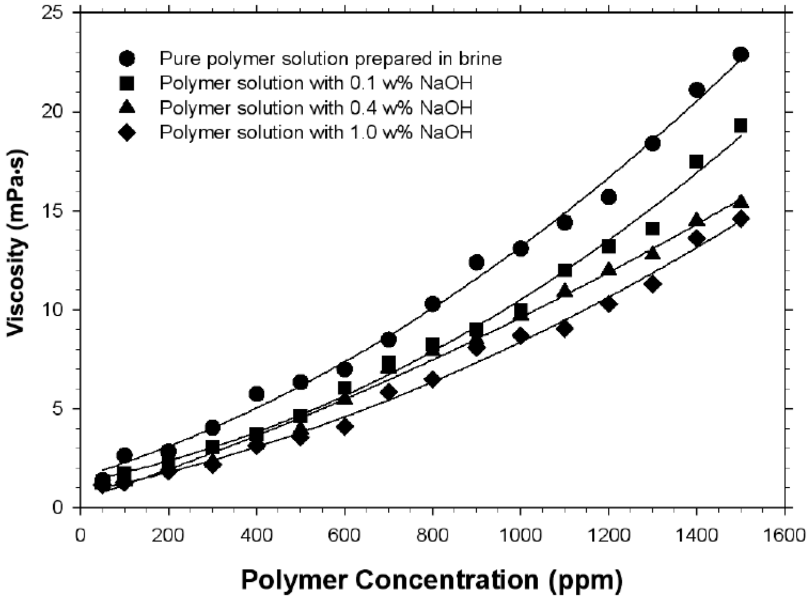


Figure 2.14 Effect of alkalineo n the viscosity of polymer solutions (Sheng, 2011)

Moreover, since alkaline and polymer reaction hydrolyzes polymer. Alkaline is consumed by the reaction. Thus, the alkaline concentration and pH decrease according to the aging. Figure 2.15. shows that the polymer viscosity is higher at lower alkaline concentration but become lower with the running time; thus, the aging of alkaline and polymer can change the trend of polymer solution viscosity (Sheng et al., 1994).

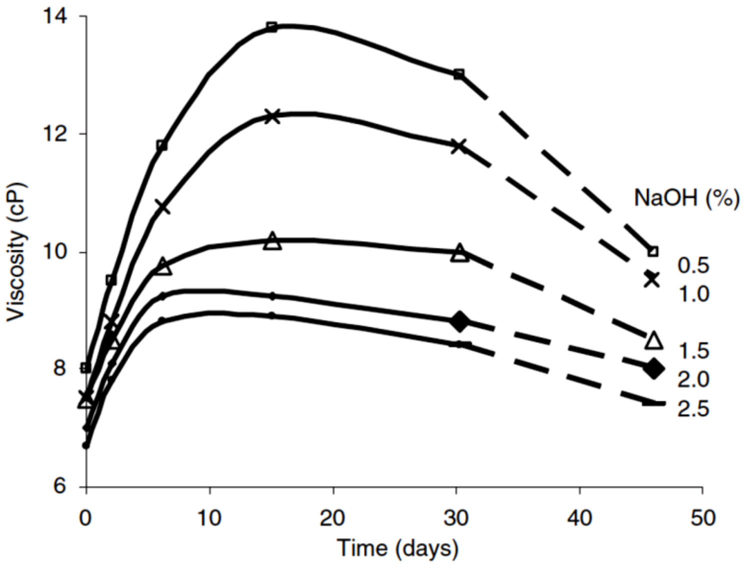


Figure 2.15 NaOH-HPAM solution viscosity versus time: 21.5% hydrolysis, 1000 mg/L HPAM, 60C (Sheng et al., 1994)

2) Polymer effect on alkaline

There is no consensus regarding the polymer effect on alkaline/oil IFT. Generally, it is believed that polymer has little effect on the IFT. Sheng et al. (1994) made the observations that the addition of polymer could increase or decrease IFT depending on the type of alkaline in the system for example; the mixed solution of Na_2CO_3 with HAPM will has IFT lower than the solution of NaOH and HPAM at the same alkaline concentration. Moreover, IFT decrease with aging and polymer hydrolysis as alkaline is consumed more and more. However, the optimum alkaline concentration is still considered importantly because it creates the lowest IFT (Sheng et al., 1994). Samanta et al. (2012) summarized from her experiments that additional recovery increases only marginally depends on concentration of HPAM and salinity in solution. Injection of polymer increases the sweep efficiency, and hence, oil recovery. After a certain salinity condition and concentration of polymer, the sweep efficiency approaches to its limiting value and thus only marginal additional recovery is observed.

From laboratory test results showed that in AP system, alkaline competes with polymer for positive-charged sites. Thus, polymer adsorption is reduced because the rock surfaces become more negative-charged sites (Krumrine and Falcone, 1983). In alkaline-polymer flooding, alkaline reaction with crude oil results in soap generation, wettability alteration, and emulsification; and polymer provides the required mobility control. Alkaline-polymer flooding can displace more residual oil than individual alkaline flooding or polymer flooding. The combination of alkaline and polymer flooding can have three variations: (1) alkaline injection followed by polymer injection (A/P), (2) polymer injection followed by alkaline injection (P/A), and (3) alkaline and polymer co-injection (A□P). The recovery factor from the third injection mode is not only higher than the alkaline injection alone or polymer injection alone, but also higher than that from the first or second mode (Sheng et al., 1994).

2.5.1.2 Effect of salinity in AP flooding

In the mixing with surfactant, salinity effect was demonstrated in term of salinity gradient: (1) ahead of the active region, the system is over-optimum (Type II+), surfactant is retarded by partitioning into the oil phase, (2) the system passes through the active region of ultra-low IFT (Type III) where residual oil displacement takes place, (3) behind the active region, the system is under-optimum (Type II-) with lower-phase microemulsion and the surfactant propagates with the water phase velocity (Glover et al., 1979; Pope et al., 1979; Hirasaki et al., 1983). Thus the salinity gradient tends to focus the surfactant near the displacement front where salinity is optimal and the phase behavior is Winsor Type III. Since, polymer dominates in water phase, the salinity gradient helps to maintain polymer flowing in the same phase with the surfactant for the Type II- conditions behind the active region. The polymer is in the excess-brine phase in the Winsor II & III phase environments (Gupta, 1981). Over-optimum salinity environment, Type II+, can have viscous, high internal-phase, water-in-oil emulsions that may be bypassed by the subsequent lower salinity fluids. In practice, the surfactant slug is injected in near-optimal to under-optimum salinity environment that is middle to low salinity (Hirasaki et al., 1983). Moreover, Shunhua et al. (2010) summarized that if the injected salinity is somewhere in the ASP system of the alkaline injection, then the profile of injection must pass through the optimal condition where the IFT is a minimum. If the injected salinity is below the optimal point, then the profile of low IFT is narrow and the IFT may increase before all of the mobilized oil is displaced. In the opposite site, if the injected salinity is near or above the optimal point, the surfactant and soap partition preferentially into the oil phase and are retarded, also resulting less effect of IFT reduction.

2.5.2 Alkaline – Surfactant flooding (AS)

In the combination of alkaline and surfactant, since alkaline reacts with the naphthenic acids in crude oil to generate soap in situ, some may believe the purpose of adding alkaline to surfactant flooding is to generate soap; so that the amount of injected surfactant can be reduced. Although generating soap is important, the reduction of surfactant adsorption is probably even more important.

2.5.2.1 Mechanism of AS flooding

Figure 2.16 shows variations of IFT with surfactant concentration at different NaOH concentrations. It is found that, in the tested surfactant concentration range (0.05-1.00 %wt), the ultra-low IFT cannot be obtained for a pure surfactant solution. Once alkaline is added into the surfactant solution, however, the IFT is significantly reduced. In particular, the measured IFT reaches the order of 10^{-3} mN/m at 0.15 %wt surfactant concentration, in conjunction with 1.0 %wt NaOH. Moreover, it is found that there always exists a minimum IFT in each low or ultra-low IFT curve.

This fact is probably because of equal partitioning of surfactant in the oil and the brine phases at certain surfactant concentration. The surfactant used in this study has both oil-soluble and water-soluble species. At a lower surfactant concentration, the water-soluble species remain in the aqueous phase while the oil-soluble species stay in the oil phase, both of which can be absorbed at the oil brine interface. At certain concentration, partitioning of surfactant becomes equal in both the oil and the aqueous phases and then the minimum IFT is achieved. As the surfactant concentration increases, the concentrations of both oil-soluble species and water-soluble species increase. Finally, the water-soluble species in the aqueous phase reach their critical micelle concentration (CMC) and begin to form micelles. In this case, the oil-soluble species can partition into the oil phase or solubilize in the micelles in the aqueous phase. The solubilization of the oil-soluble species in the micelles decreases the CMC and thus the surfactant monomer concentration as well. The reduction in monomer concentration leads to a decrease in interfacial concentration of the water-soluble species and thus an increase in IFT. Hence, the IFT increases after the minimum (Sheng, 2011). Thigpen et al. (1991) added surfactant to the alkaline solution results in reducing the oil/water IFT. The surfactant was soluble in both the aqueous solution and the reservoir oil but more soluble in the former. The addition of surfactant made alkaline flooding more efficient. Rudin et al. (1994) investigated the effect of adding surfactant on interfacial tension and spontaneous emulsification in alkaline and acidic oil systems. They found that adding surfactant reduced the equilibrium IFT to an ultralow value. The addition of surfactant also caused a higher interfacial resistance to mass transfer, which reduced the rate of acid ionization, resulting in a longer period of low dynamic IFT. Also, the pH range for ultralow IFT and for spontaneous emulsification was also widened.

Hanna and Somasundaran (1977) conducted tests on Berea sandstone/ Mahogany sulfonate and kaolinite/dodecylsulfonate systems to determine the effect of solution pH on adsorption. For the former system at a constant ionic strength of 0.01 M NaCl, the adsorption densities are found to be 0.66 and 0.4 mg/m^2 for the initial pH conditions of 5 and 11, respectively, and the corresponding final pH values were not much different from each other (12.3 and 12.8). The results obtained from the kaolinite/dodecylsulfonate system also showed that the adsorption of sulfonate on kaolinite decreased with increase in pH. These observations are in agreement with what would be expected from the fact that the mineral will become increasingly negatively charged with an increase in pH and thereby possibly retard the adsorption of an anionic surfactant such as sulfonate. Another mechanism for alkaline additives to reduce surfactant retention may be caused by the removal of multivalent ions

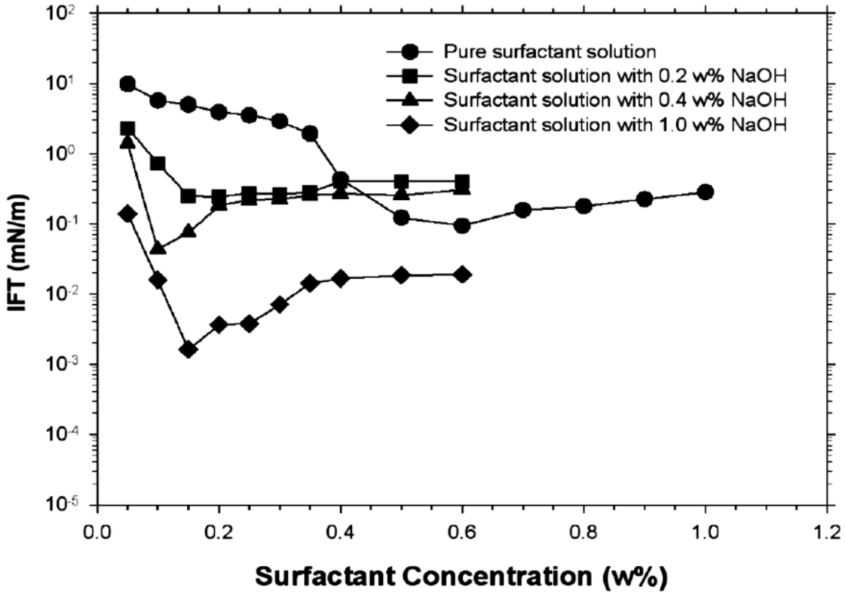


Figure 2.16 Variations of IFT with surfactant concentrations at different NaOH concentrations (Sheng, 2011)

2.5.2.2 Effect of salinity in AS flooding

Zhang et al. (1998) investigated IFT in the AS system. The system demonstrated obvious synergy. The synergy more likely affected the early-stage IFT in a low ionic strength or low salinity condition. In a high ionic strength or high salinity condition, the IFT was more affected by the added synthetic surfactant. The surfactant concentrations and their ratios determine the value of IFT.

Shunhua et al. (2010) concluded that surfactants can produce high oil recoveries over a wide range of optimal and under-optimum conditions but not at over-optimum conditions, owing to surfactant retention in trapped oil. They also supported that the dispersion on the ASP process is important to salinity effect in the system. If the injected salinity is somewhere between the soap and injected surfactant, then the profile of the soap/surfactant ratio must pass through the optimal ratio where the IFT is a minimum. If dispersion is small and the injected salinity is below the optimal curve, then the profile of ultralow IFT is narrow, resulting IFT may increase before all of the mobilized oil is displaced. If dispersion is large and the injected salinity is again below the optimal curve, then the profile of the ultralow IFT is wide and the displacement front has more distance to displace the mobilized oil before the IFT increases.

When the injected salinity is near or above the optimal curve, the effect of dispersion is to retard the displacement front. This occurs because the decreasing surfactant concentration at the back of the surfactant slug interferes with the front of the surfactant slug. This results in the maximum surfactant concentration decreasing. The reduced surfactant concentration increases the soap/surfactant ratio. When the soap/surfactant ratio becomes greater than the optimum ratio at the local salinity, the surfactant and soap partition preferentially into the oil phase and is retarded. Dispersion reduces surfactant concentration faster than soap concentration because the surfactant is a slug with two dispersion mixing zones, while the soap is dispersed on the back side of a bank that grows with displacement.

The effects of dispersion are compensated by application of a salinity gradient. There is no benefit of having over-optimum salinity ahead of the displacement front because the soap/surfactant ratio already results in over-optimum conditions there, even in the case of constant salinity. However, under-optimum salinity in the drive behind the surfactant slug is beneficial because it raises the optimal soap/surfactant ratio, transfers the surfactant and soap into the aqueous phase, and increases the velocity of the displacement front. This is the same as in conventional surfactant flooding, where a low-salinity drive can remobilize surfactant trapped in the oil (Hirasaki et al. 1983)

2.5.3 Surfactant – Polymer flooding (SP)

In surfactant-polymer (SP) flooding processes, if designed correctly, the surfactant increases the capillary number, which is crucial for the mobilization and polymer increases the sweep efficiency by lowering the mobility ratio. These can result to great additional oil recovery. However, when surfactant and polymer are injected in the same slug (SP flooding), their compatibility is an issue. Sometimes, polymer is injected before surfactant as a sacrificial agent for adsorption or for conformance improvement. Sometimes polymer is injected behind surfactant to avoid chase water fingering in the surfactant slug. Even though polymer is not injected with surfactant in the same slug, they will be mixed at their interface because of dispersion and diffusion. So, the observation of mechanism of SP is needed to be considered.

2.5.3.1 Mechanism of SP flooding

1) Surfactant effect on polymer

Surfactant can stay in the aqueous, oleic, or middle micro-emulsion phase; however, polymer in a surfactant-polymer solution stays in the most aqueous phase, no matter where the surfactant is (Nelson, 1981). Surfactant has two effects on polymer viscosity:

surfactant brings cations such as Na^+ to reduce polymer viscosity and addition surfactant, aggregates can be formed so that polymer viscosity is increased. Moreover, the viscosity of hydrophobic associating polymers is very sensitive to surfactant concentration. The reason is that the hydrophobic group in the polymer can be solubilized into micelles so that their molecular interaction becomes larger (Li, 2007). However, Sheng (2011) suggested that, under the reservoir condition, the surfactant can be mixed with polymer which leads to change of viscosity of the polymer solution. His experiments showed that the apparent viscosity of polymer decreases in the presence of surfactant. These results indicated that anionic surfactant affects the viscosity behavior of polyacrylamide through charge-shielding mechanism, which causes the shrinkage of molecular chains of polymer and the decrease of hydrodynamic radius. Therefore he concluded that it is very important to simulate the viscosity of polymer solutions or mobility ratio for any ASP injection process.

2) Polymer effect on surfactant

The effect of polymer on systems with oil is to increase the viscosity of the water-rich phase only, with little effect on the microemulsion phase unless it is the water-rich phase. So, little difference is observed in the IFT values with and without polymer. The three-phase systems still exhibit ultralow IFT values. With the presence of polymer, the optimum salinity is decreased slightly (Pope et al., 1982). When a polymer is added in a surfactant system, there are two critical concentrations: CAC and CMC_2. CAC is the critical adsorption concentration at which surfactant starts to adsorb on the polymer chains; it is lower than the critical micelle concentration (CMC). CMC_2 is the surfactant concentration at which micelles are formed when polymer is present; it is higher than CMC (Li et al., 2002). For evaluating the effect of polymer on the surface properties, surface tension measurements of surfactants have been performed in the presence and absence of polymer. It may be seen that polymer increases the surface tension of the surfactant solution due to interaction of the functional group of both polymer and ionic surfactant. Trushenski (1977) reported that the presence of polymer in the surfactant slug caused an unexpected increase in surfactant loss. This increase was due to the bypass of surfactant by polymer (phase trapping). However, the trapped sulfonate phase could be displaced by chase water behind the mobility buffer bank. When the polymer concentration increased, the sulfonate concentration decreased. When the polymer concentration peaked, the sulfonate concentration decreased sharply. When the polymer concentration decreased, the sulfonate concentration increased, indicating that the sulfonate was remobilized. Although the trapped sulfonate could be displaced, it was not effective in displacing oil.

2.5.3.2 Effect of salinity in SP flooding

In SP flooding, the effect of salinity is in the same trend as AP flooding. At the point of optimum salinity, which is in range of low to middle salinity, and optimum surfactant create the lowest IFT. For polymer, low salinity can increase the polymer solution viscosity. However, the presence of polymer in surfactant slug cause increase in surfactant loss due to the trapping of surfactant by polymer. Thus, in order to achieve the same IFT, optimum concentration should shift to be higher. Then, optimum salinity also changes but it is system dependence, so it can either increase or decrease according to increase optimum surfactant concentration.

Chapter 3

Overview of Numerical Simulation of Low Salinity combined with Alkaline/ Surfactant/ Polymer and ASP Flooding

3.1 Synthetic Model and Properties

In this study, synthetic model of dimension 150 meters, 150 meters and 6 meters in I, J and K directions, respectively, was simulated in flood test by Eclipse 100 (2009.1) simulator. The model was created to be 50, 50 and 6 grids blocks in I, J and K directions in Eclipse-100. There were 2 wells: injector and producer which were placed in grid number 1, 1, 1-6 and 50, 50, 1-6 respectively. Both wells were controlled by reservoir volume rate (RESV) at 100 m^3/day. The property details of the reservoir model were taken from Kossac Chuck, Schlumberger advisor (Kossac, 2012), which used in his low salinity water flooding study. The model is heterogeneous with patterns variation in permeability and porosity. The porosity range is 0.23 to 0.306 and the permeability range is between 275 to 525 mD and. The porosity pattern variation and permeability pattern variation are shown in Figure. 3.1 and Figure. 3.2

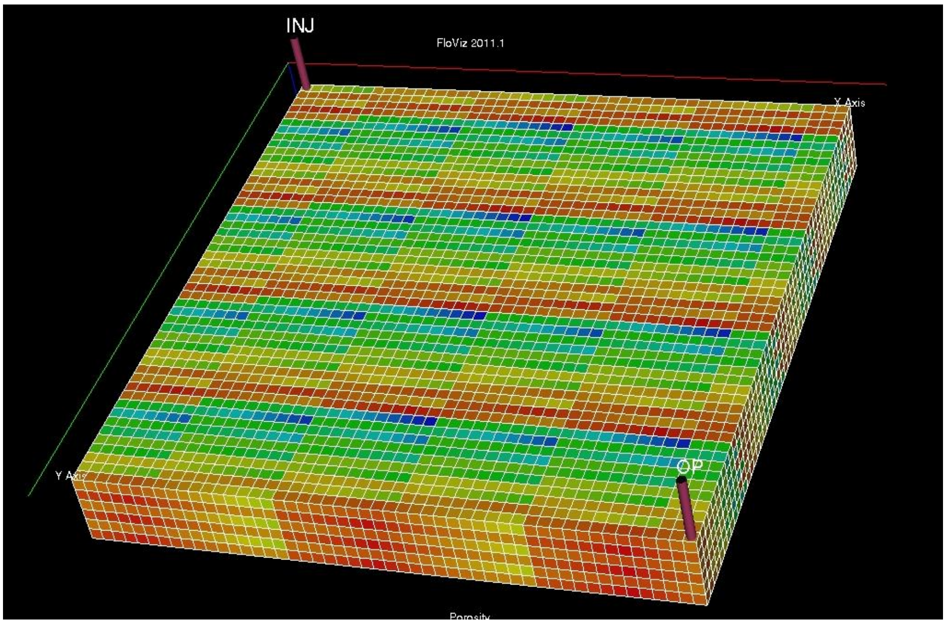


Figure 3. 1 The porosity pattern variation of synthetic model (Kossack, 2012)

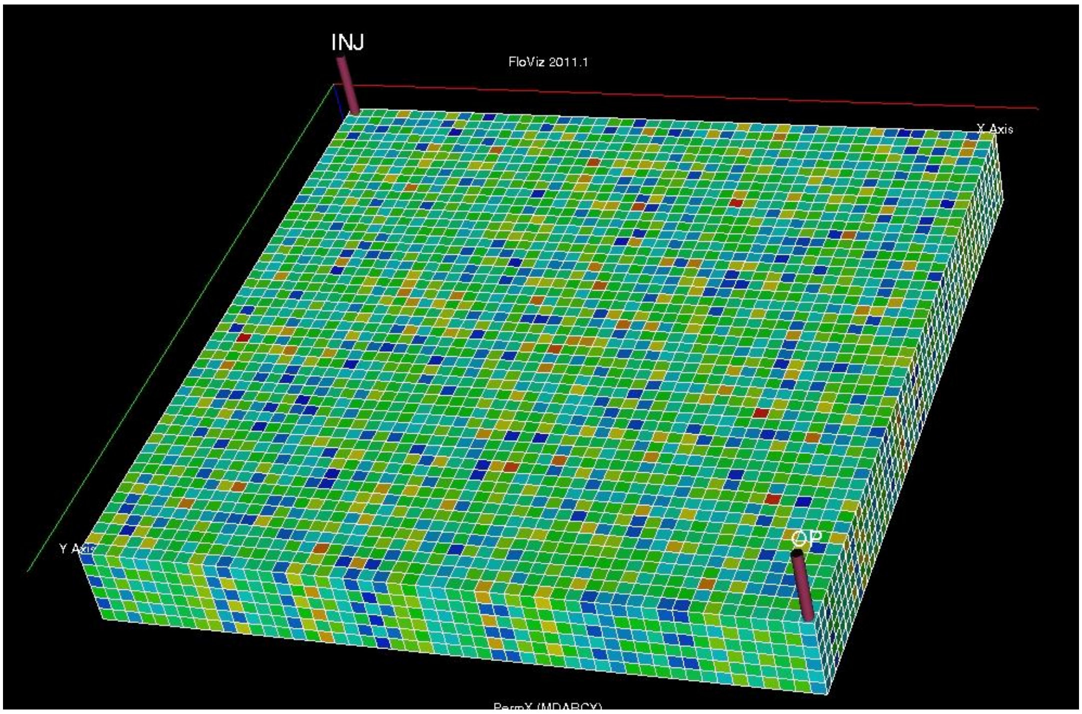


Figure 3. 2 The permeability pattern variation of synthetic model (Kossac, 2012)

The active phases presented in the model were oil and water. The water and oil properties were also based on Kossac study (Kossac, 2012). At the reference pressure between 200-300 barsa, the initial oil and water viscosity were 2cP and 0.5 cP at reservoir condition and initial oil and water density were 850 kg/m3 and 1000 kg/m3 at surface condition. The conventional injected water was composed of 40000 ppm salinity represented as sea water or high salinity water. In this study, it was assumed that formation water has same salinity to sea water that is 40000 ppm.

The reference case or the base case is the case that uses high salinity water flooding technique from the starting to the end of production, totally 5 years or a1825 days. The reference data file and all properties are available in Appendix.

3.2 Low Salinity Water Flooding Model and properties

In low salinity water flooding, the salt is modeled as a single component in water phase. This option can be activated by keyword LOWSALT in the RUNSPEC section. It allows the user to modify the saturation and relative permeability end points for water and oil phases as a function of the salt concentration. Therefore, two sets of saturation functions, one for the high salinity and one for the low salinity must be given as an input. The saturation end points are first modified as:

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

$$S_{wcr} = F_1 S_{wcr}^L + (1 - F_1) S_{wcor}^H$$

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

$$S_{owcr} = F_1 S_{owcr}^L + (1 - F_1) S_{owcr}^H \qquad \text{[EQ. 3.1]}$$

where

F_1	is a function of the salt concentration, and correspond to the second column of the LSALTFNC keyword.
S_{wco}	is the connate water saturation
S_{wcr}	is the critical water saturation
S_{wmax}	is the maximum water saturation
S_{owcr}	is the critical oil saturation in water
H	is index for high salinity
L	is index for low salinity

The F1 factor is a function of salt concentration and must be provided as a look-up table using the LSALTFNC keyword. Then the relative permeability for water and oil, and oil-water capillary pressure are also found by look-up table at the scaled saturations using the SWOF keyword, and then interpolated similarly as:

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

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

$$P_{cow} = F_1 P_{cow}^L + (1 - F_2) P_{cow}^H \qquad \text{[EQ. 3.2]}$$

where

F_2	is a function of the salt concentration, and corresponds to the third column of the LSALTFNC keyword
k_{rw}	is the water relative permeability
k_{ro}	is the oil relative permeability
P_{cow}	is oil-water capillary pressure

The keyword LSALTFNC, which is activated in the PROPS section, is set to indicate salt concentrations and weighting factor inputs for low salinity - F1, F2 factors. F1 is the weighting factor for calculating the low salinity saturation endpoints and the relative permeability interpolation, while F2 is weighting factor for capillary pressures. Therefore, the weighting factors determine the effectiveness of salinity. In the most ideal case, this values LSALTFNC table is tabulated from the laboratory measurements and up scaled to field. In this study, F1 and F2 factors perform in the same nature as shown in Table.3.1. The F1 factor value of 0 means that the high salinity saturation functions will be used while the value of 1 means low salinity saturation functions will be used. The threshold salinity is between 1000-5000 ppm, means that when salinity less than 1000 ppm or more than 5000 ppm, the system will be less affected, compared to the threshold range of salinity. Figure.3.3 shows the relationship of salinity to weighting factor (Jerauld, 2008).

Table 3. 1 The LSALFNC (F1, F2) table

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

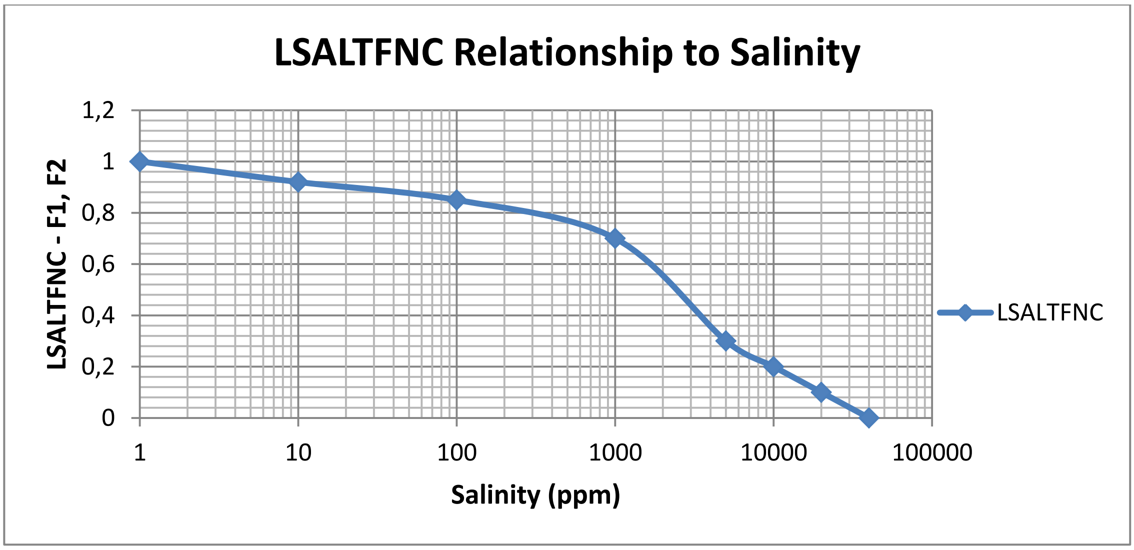


Figure 3. 3 the relationship of salinity and weighting factor (F1,F2) (Jerauld, 2008)

3.2.1 Defining Low and High salinity curves

The SWOF keyword in PROPS section is input tables of water and oil relative permeability and water-oil capillary pressure as functions of the water saturation. Keyword SATNUM in the REGIONS section defines which table of saturation function (SWOF) represents the high salinity saturation. Additional low salinity saturation function table is also required within SWOF keywords. The keyword LWSLTNUM must then be used in REGIONS section to associate low salinity table number to each grid block.

In this study, the high salinity and low salinity relative permeability and saturation table was based on one dimensional simulation study from Mohammadi et al. (2012). They conducted results from 1D simulation runs of high and low salinity water flooding. A low salinity water flooding changes the shape of the relative permeability curve due to wettability changes toward more water wet rock as shown in Fig 3.4. See the data point in Appendix

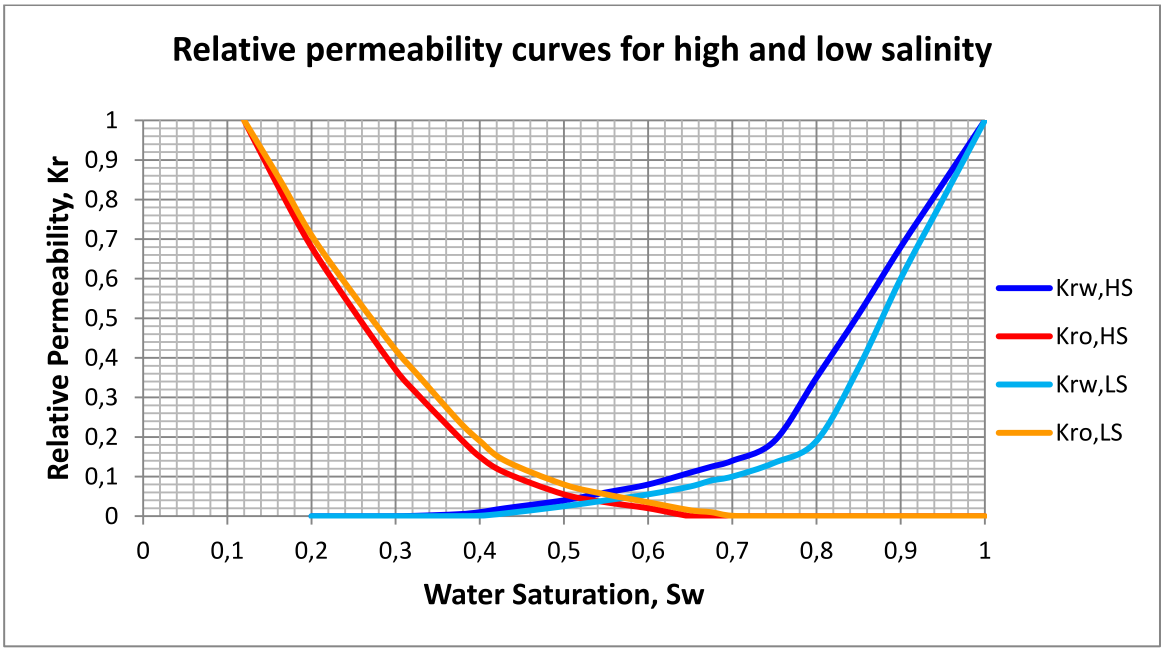


Figure 3. 4 The oil and water relative permeability curves for high (HS) and low salinity (LS) (Mohammadi et al., 2012)

3.2.2 Setting the initial conditions

In generally, when low salinity option is active, keyword PVTWSALT in PROPS section is used to supply the water PVT data for simulation. However, this keyword has to be replaced by PVTW keyword when the chemical flooding: polymer, alkaline and surfactant are active in the same system. Using this keyword allows the users to specify formation salt concentration, the water formation volume factor, water compressibility and water viscosity at the reference pressure as a function of salt concentration. Meanwhile, PVDO keyword is used to supply the oil PVT data. As state at the beginning, the connate water has viscosity 0.5 cp and oil viscosity is constant at 2 cp between the reference pressures range 200 – 300 barsa.

The initial salt distribution throughout the synthetic model is specified in the SOLUTION section. If the initial conditions are determined by equilibration, the salt concentration can be varied with depth independently in each equilibration region. The SALTVD keyword supplies a table of salt concentrations versus depth for each equilibration region. The salt concentration is assumed to be constant at 40000 ppm from the depth below 5000 meters in this study.

To control the concentration of salt in the injection stream, WSALT keyword is needed in SCHEDULE section. But for combination with chemical flooding, the salt concentration can be input in WPOLYMER keyword instead.

3.2.3 The studied cases

Since we injected continuous high salinity (HS) water flooding from the first day to the last day of production, the same way with continuous low salinity (LS) or brine 1000 ppm was done in order to compare the effect of salinity in general with the base case. Then, the effect of timing for secondary recovery phase was studied by using HS as the first phase and changing the starting day of continuous LS injection for the second phase. The best result of timing study was continued using for varying the salinity of LS in the second phase flooding. The low salt concentration that could give the reasonable recovery was represented as low salinity and used for all simulation cases in this study. The last one is to change the size of LS slug in the second phase, while keeping the same HS flooding in the first phase, the day of starting LS slug and HS flooding for the tertiary phase recovery.

3.3 Alkaline Flooding Model and Properties

The alkaline flooding model is activated by specifying the ALKALINE keyword in the RUNSPEC section. The alkaline is assumed to exist only in the water phase as adding concentration in the water injector. Alkaline alone react with petroleum acids to form in-situ surfactant that help releasing oil from the rock by reducing water-oil surface tension. Then, oil can be moved easier through the reservoir to production well. However, when alkaline is used in conjunction with surfactant and polymer to perform Alkaline-Surfactant-Polymer flooding (ASP), the alkaline can reduce the adsorption of both surfactant and polymer on the rock surface; thus it can increase the effectiveness of surfactant and polymer flooding methods.

In this study, the alkaline properties were conducted from the study of Maheshwari Y.K. (2011). His work was carried on comparative simulation study of chemical EOR methodologies (alkaline, surfactant and/or polymer) applied to Norne Field E-Segment in the North Sea.

3.3.1 Alkaline effect on water-oil surface tension

ALSURFST keyword is the main property that indicated the water-oil surface tension multipliers as a function of alkaline concentration. The initial water-oil surface tension value can be found in surfactant properties part that equals to 30×10^{-3} N/m. This effect of alkaline can also be combined with effect of surfactant by modifying the water-oil surface tension as follows:

$$\sigma_{wo} = \sigma_{wo}\left(C_{surf}\right) A_{st}\left(C_{alk}\right) \qquad \text{[EQ. 3.3]}$$

where

$\sigma_{wo}\left(C_{surf}\right)$	is the surface tension at surfactant concentration and zero alkaline concentration (SURFST keyword).
$A_{st}\left(C_{alk}\right)$	is the surface tension multiplier at alkaline concentration (ALSURFST keyword).

ALSURFST table is shown in Table 3.2. It is indicated that when alkaline concentration is increased, the water-oil surface tension multipliers become less than one and decreased accordingly; thus, the water-oil surface tension decreases.

Table 3. 2 The ALSURFST table shows the IFT multiplier as function of alkaline concentration (Maheshwari Y.K., 2011)

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

3.3.2 Treatment of adsorption

The adsorption of alkaline is assumed to be instantaneous. The isotherm adsorption can be specified either by a generic analytical adsorption model using the ADSORP keyword or by the look-up table of adsorbed alkaline as a function of alkaline concentration using the ALKADS keyword, which is used in this study. Table.3.3 shows the ALKADS values define that alkaline adsorption by rock increase with alkaline concentration but in the limitation.

In addition, alkaline desorption can be also set by using ALKROCK keyword. If alkaline desorption is in process, then the alkaline adsorption isotherm is retraced whenever the local alkaline concentration in the solution decreases. In contrast, if the desorption is prevented, then the adsorbed alkaline concentration does not decrease with time and the alkaline effect on polymer or surfactant adsorption is assumed to be permanent: the multiplier tables in ALSURFAD or ALPOLADS keywords are not retraced when the alkaline concentration decreases. The desorption prevention is assigned in this study.

Table 3.3 The ALKADS table shows alkaline adsorption as function of alkaline concentration (Maheshwari Y.K., 2011)

Alkaline Concentration (kg/m3)	Adsorbed alkaline on rock (mg/kg)
0.0	0.0
3.0	0.005
6.0	0.007
9.0	0.008
10.0	0.009

3.3.3 Alkaline effect on surfactant/polymer adsorption

Apart from reducing water-oil surface tension in the reservoir, the alkaline can also reduce the adsorption of both surfactant and polymer on the rock surface. This is modeled by modifying the mass of adsorbed surfactant or polymer as follows:

$$\text{Mass of adsorbed surfactant or polymer} = V\rho_r C_{s,p}^{a}\left(\frac{1-\emptyset}{\emptyset}\right) A_{ad}(C_{alk}) \qquad \text{[EQ.3.4]}$$

where

V	is the pore volume of the cell
$\emptyset$	is the porosity

ρ_r is the mass density of the rock (see the SURFROCK/PLYROCK keyword)

$C^a_{s,p}$ is the surfactant/polymer adsorbed concentration obtained from SURFADS/ PLYADS/ ADSORP keywords

$A_{ad}(C_{alk})$ is the adsorption multiplier at alkaline concentration (see the ALSURFAD/ ALPOLADS keyword)

Table.3.4 shows polymer adsorption multiplier and surfactant adsorption multiplier as a function of alkaline concentration, respectively.

Table 3.4 Polymer adsorption multiplier and surfactant adsorption multiplier as a function of alkaline concentration (Maheshwari Y.K., 2011)

Alkaline Concentration (kg/m3)	Polumer adsorption multiplier	Surfactant adsorption multiplier
0.0	1	1
3.0	0.7	0.7
6.0	0.5	0.5
9.0	0.3	0.0

When the Alkaline is assumed to be adsorbed irreversibly, by preventing desorption in the ALKROCK keyword, its effect on Surfactant/Polymer adsorption is assumed to be irreversible as well. Using the previous notations, the mass of adsorbed surfactant or polymer becomes:

$$\text{Mass of adsorbed surfactant or polymer} = V \rho_r C^a_{s,p} \left(\frac{1-\emptyset}{\emptyset}\right) A_{ad}\left(C_{alk,max}\right) \quad \text{[EQ.3.5]}$$

where

$(C_{alk,max})$ is the maximum alkaline concentration reached in the block, corresponding to the actual effect on Surfactant/Polymer adsorption.

The concentration of the injected alkaline in a water injector is specified using the WALKALIN keyword in SCHEDULE section. The alkaline concentration used in this simulation is ranged between 0 - 3% wt. or in the number of 0 - 30 kg/m^3.

3.3.4 The studied cases

For the combination of low salinity water flooding and alkaline flooding model, three major effects were studied. The varying of HS and LS injection until the starting day of the secondary phase by alkaline flooding was done in order to see the effect of high and low salinity in the first phase on alkaline flooding in the second phase. Then, the alkaline solution was divided to low alkaline concentration at 1.5%wt and high concentration at 3%wt to do sensitivity analysis of the effect of alkaline concentration in secondary phase recovery. Each concentration case is prepared by mixing with low salinity case and high salinity case to observe the effect of salinity in alkaline solution.

After getting the most reasonable case to oil recovery from secondary recovery phase that could explain which salinity used in the first flooding and which alkaline concentration and salinity used to prepare alkaline solution for alkaline flooding in the second phase, it was used for studying the tertiary recovery phase. The size of alkaline slug volume in term of number of alkaline injection days was varied and also followed by HS and LS as tertiary flooding. The final result should be stated the type of first water flooding phase, type of alkaline solution mixed with brine salinity, range of alkaline flooding and the type of water flooding in the tertiary phase.

3.4 Surfactant Flooding Model and Properties

Eclipse-100, generally, does not provide the detailed chemical simulation of surfactant flooding but modeling the most important features on a full field basis. Surfactant offers a way of recovering the residual oil by reducing the water-oil surface tension. A very low oil-water surface tension reduces the capillary pressure and hence allows water to displace extra oil. Another effect that will influence the success or failure of a surfactant flood is the tendency of the surfactant being adsorbed by the rock. If the adsorption is too high, then large quantities of surfactant will be required to produce a small quantity of additional oil. All of these features, the user can define the properties of surfactant themselves as following.

Also, the properties of surfactant used as input data in this study were taken from Maheshwari Y.K. (2011) that applied to Norne Field E-Segment in the North Sea studies.

The surfactant flooding option is activated by using SURFACT keyword in RUNSPEC section. The surfactant is assumed to exist only in the water phase, and the input to the reservoir is specified as a concentration at a water injector. Therefore, the distribution of injected surfactant is modeled by solving a conservation equation for surfactant within the water phase.

3.4.1 Surfactant effect on water-oil surface tension based on capillary number calculation

SURFST keyword in the PROPS section supplies tables of water-oil surface tension as a function of surfactant concentration in the water. The SURFST data in Table.3.5 clarifies that the water-oil surface tension is decreased when the surfactant concentration increases. The initial water-oil surface tension of the system is also specifies by this keyword that equals to $30*10^{-3}$ N/m.

Table 3.5 The water-oil IFT as function of surfactant concentration (Maheshwari Y.K., 2011)

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

From Table 3.5, it can be indicated that the W/O surface tension becomes higher after surfactant concentration 10 kg/m^3; thus, this concentration is at CMC point which means that the surface tension will not decrease furthermore even higher surfactant concentration but increase slightly.

The pressure drop across trapped oil has to overcome the capillary forces that are trapping oil in order to reduce the residual oil saturation. This represents what happens when water-oil interfacial tension is reduced by surfactants. The residual oil saturation corresponds to the capillary number, the dimensionless ratio between the viscous and capillary forces. Therefore, the capillary number is considered importantly. The capillary number is calculated by:

$$N_c = \frac{|K \cdot gradP|}{ST} C_{unit} \qquad \text{[EQ.3.6]}$$

where

K	is the permeability
P	is the potential
ST	is the interfacial tension (see SURFST keyword)
C_{unit}	is the conversion factor depending on the units used.
$\lvert K \cdot gradP \rvert$	is calculated as

$$\lvert K \cdot gradP \rvert = \sqrt{(K_x \cdot gradP_x)^2 + (K_y \cdot gradP_y)^2 + (K_z \cdot gradP_z)^2} \qquad \text{[EQ.3.7]}$$

where foe cell i

$$K_x \cdot gradP_x = 0.5\left[\left(\frac{K_x}{D_x}\right)_{i-1j} \cdot (P_i - P_{i-1}) + \left(\frac{K_x}{D_x}\right)_{j,j+1} \cdot (P_{i+1} - P_i)\right] \qquad \text{[EQ.3.8]}$$

The K/D value is calculated in an analogous manner to the transmissibility and depends on how the geometry was specified.

According to the capillary number, as the concentration of surfactant increases, water-oil capillary pressure decreases resulting to get the reduction of residual oil saturation. The oil water capillary pressure is taken as:

$$P_{cow} = P_{cow}\,(S_w)\frac{ST(C_{swf})}{ST(C_{swf=0})} \qquad \text{[EQ.3.9]}$$

where

$ST(C_{swf})$	is the surface tension at the present surfactant concentration.
$ST(C_{swf=0})$	is the surface tension at zero concentration.
$P_{cow}\,(S_w)$	is the capillary pressure from the immiscible curves initially scaled to the interpolated end-points calculated in the relative permeability model.

3.4.2 Relative permeability curves

The Relative Permeability model is essentially a transition from immiscible relative permeability curves at low capillary number to miscible relative permeability curves at high capillary number. SURFCAPD keyword is used to define the transition as function of capillary number as shown in Table.3.6. Miscibility function of value 0 and 1 are represented immiscible and miscible condition, respectively. It indicates that the immiscible flooding dominates the system when the capillary number is lower than 10^{-5}, while miscible flooding does if the capillary number is over $3.16*10^{-3}$.

Table 3.6 The SURFCAPD table defines the transition as function of capillary number (Maheshwari Y.K., 2011)

Log of Capillary No.	Miscibility function
-8	0
-7	0
-6	0
-5	0
-2.5	1
0	1
5	1
10	1

The relative permeability used at a value of the miscibility function between the two extremes is calculated in two steps. Firstly the end points of the curve are interpolated and both the immiscible and the miscible curves are scaled to honor these points. The relative permeability values are looked up on both curves, and the final relative permeability is taken as an interpolation between these two values. This procedure is illustrated in Figure.3.5 for the oil to water curve.

The miscible relative permeability curve is specified using the SURFNUM keyword while immiscible curve is specified by SATNUM keyword in REGIONS section in conjunction with the saturation function keywords; SWOF.

In combination of surfactant flooding with low salinity water flooding option, the relative permeability curves need to be considered specially. The system is divided to be:

(1) Immiscible relative permeability curves :- high salinity and low salinity curves

The relative permeability curves are interpolated based on the normal system as showed in Figure.3.4.

(2) Miscible relative permeability curves: - high salinity and low salinity curves.

The miscible relative permeability curves for high salinity system are based on the ideal curves (Emegwalu, C.C., 2009, Maheshwari Y.K., 2011). The curves are shown in Figure.3.6. The low salinity curve is interpolated from the ideal high salinity curves using the low salinity function.

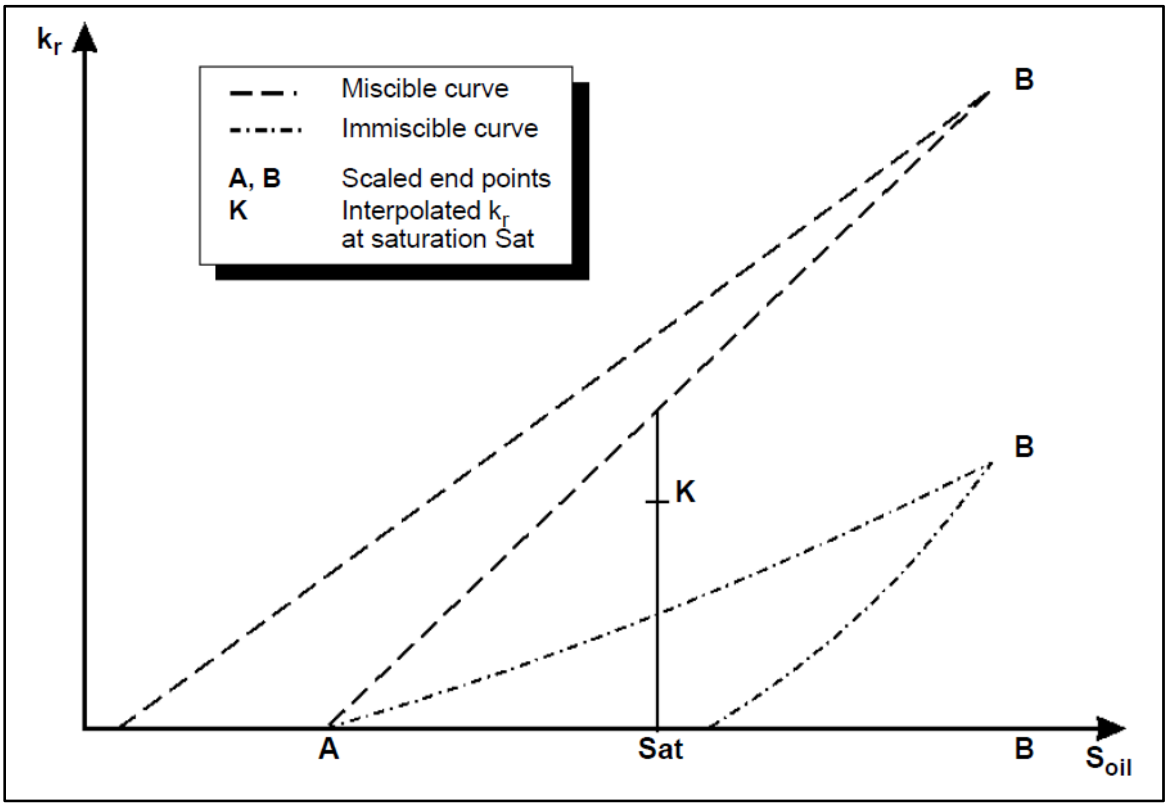


Figure 3. 5 The procedure to interpolate miscible/ immiscible relative permeability curve (Eclipse manual)

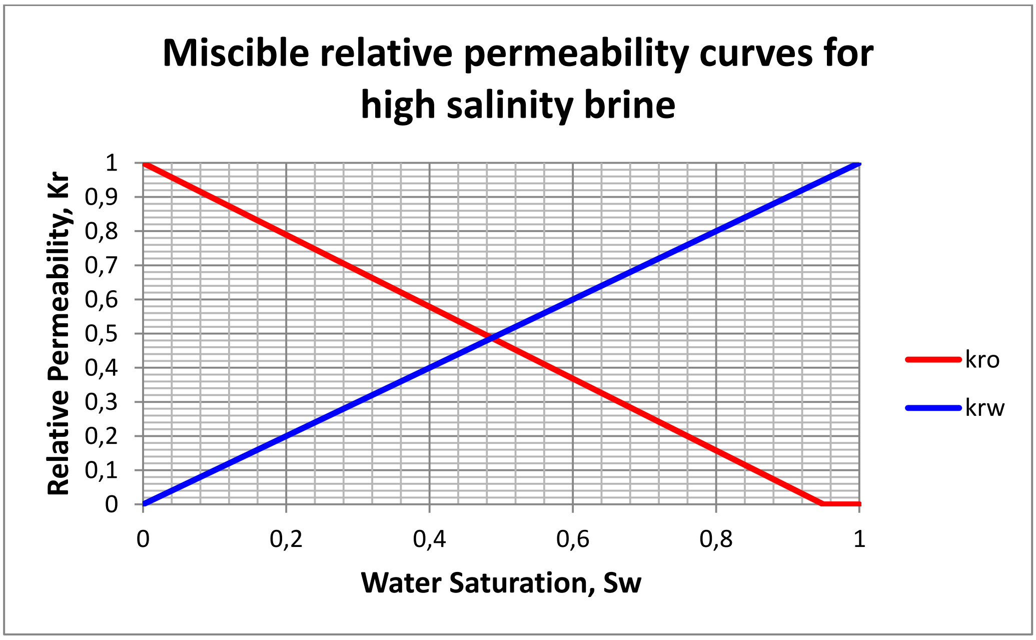


Figure 3. 6 The miscible oil and water relative permeability curves at high salinity condition (Emegwalu, C.C., 2009, Maheshwari Y.K., 2011)

3.4.3 Effect of viscosity

The water PVT data is input using PVTW keyword. Viscosity of the mixture is also affected by surfactant injection. The input of surfactant viscosity is a function of surfactant concentration using the SURFVISC keyword and it is used to calculate the water-surfactant solution viscosity as follows:

$$\mu_{ws}\left(C_{surf}, P, c_s\right) = \mu_w(P, c_s) \cdot \frac{\mu_S(C_{surf})}{\mu_w(P_{ref})} \qquad \text{[EQ.3.10]}$$

If the Brine option is active (and the Polymer option is inactive), the previous equation becomes a function of salt concentration as well:

$$\mu_{ws}\left(C_{surf}, P, c_s\right) = \mu_w(P, c_s) \cdot \frac{\mu_S(C_{surf})}{\mu_w(P_{ref}, C_{sref})} \qquad \text{[EQ.3.11]}$$

Where

μ_S	is the viscosity from the SURFVISC keyword
μ_w	is the viscosity from the PVTW or PVTWSALT keywords
μ_{ws}	is the viscosity of the water-surfactant mixture
P_{ref}	is the reference pressure in the PVTW or PVTWSALT keywords
C_{sref}	is the reference salt concentration in the PVTWSALT keywords.

In this study, Table 3.7 shows the value of SURFVISC keyword that is surfactant viscosity function describing the effect on the viscosity of pure injected water of increasing the concentration of surfactant in solution. These viscosities are used as base values in case of combination of surfactant and polymer. The polymer viscosity multiplier will take these numbers to calculate further with salinity effect. So, the water viscosity does not change much due to surfactant adding even though normal surfactant can cause gel problem in reality.

Table 3.7 The SURFVISC table shows water viscosity as function of surfactant concentration (Maheshwari Y.K., 2011)

Surfactant Concentration (kg/m3)	**Water Viscosity (cP)**
0.00	0.5
10.00	0.54
20.00	0.6

3.4.4 Treatment of adsorption

The adsorption of surfactant is assumed to be instantaneous, and the quantity adsorbed is a function of the surrounding surfactant concentration. As same as alkaline flooding, specifying by using either ADSORP keyword with SURFACT as an argument or SURFADS is required to supply an adsorption isotherm as a function of surfactant concentration. SURFADS keyword is selected to use in this simulation and the function is shown in Table. 3.8.

Table 3. 8 The SURFADS shows surfactant adsorption as function of surfactant concentration (Maheshwari Y.K., 2011)

Surfactant Concentration (kg/m^3)	**Surfactant Adsorption by rock (mg/kg)**
0.0	0.00
1.0	0.17
5.0	0.17
10.0	0.17

Moreover, the surfactant desorption is needed to be consider by using SURFROCK keyword. The desorption model ensures that each grid block retraces the adsorption isotherm as the surfactant concentration falls in the cell. The desorption preventing model assumes that the adsorbed surfactant concentration on the rock may not decrease with time and this model is used in this study. The quantity of surfactant adsorbed on to the rock is given by:

$$Mass\ of\ adsorbed\ surfactant \ = \ PORV \cdot \left(\frac{1-\emptyset}{\emptyset}\right) \cdot MD \ \cdot CA(C_{surf}) \qquad \text{[EQ.3.12]}$$

where

$PORV$	is the Pore volume of the cell
$\emptyset$	is the Porosity
MD	is the mass density of the rock (see SURFROCK keyword)
$CA(C_{surf})$	is the adsorption isotherm as a function of local surfactant concentration in solution.

The concentration of the injected surfactant in the water injector is specified using the WALKALIN keyword in SCHEDULE section. The surfactant concentration used is ranged between 0-2% wt. or in another meaning that 0-20 kg/m^3.

3.4.5 The studied cases

The combination of low salinity water flooding and surfactant flooding models were done in the same way as alkaline flooding, thereby, there were study on three major effects: effect of surfactant concentration in secondary phase recovery, effect of salinity in surfactant solution and effect of using high and low salinity in the first phase to surfactant flooding in the second phase. The methods of simulation were similar but different in surfactant concentration as using 1%wt stood for low surfactant concentration and 2%wt stood for high concentration,

The tertiary phase of the combination study was tested similar to alkaline flooding as well. When obtaining the most reasonable case to oil recovery from secondary recovery phase that give the type of salinity used in the first flooding and which surfactant concentration and salinity used in surfactant flooding in the secondary phase, that case was continued using to vary the range of surfactant injection and also the type of tertiary flooding: either HS or LS. The final result should give the type of first water flooding phase, concentration of surfactant and salinity used in preparing surfactant solution, range of surfactant flooding and the type of water flooding in the tertiary phase.

3.5 Polymer Flooding Model and Properties

The main objective of polymer injection during water flooding is to decrease the mobility of the injected water, resulting to more favorable fractional flow curve of injected water, more efficient sweep pattern and viscous fingering reducing. In generally, the reduced mobility of water from adding polymer is due to two effects. Firstly, since the viscosity of the polymer solution is higher than pure water, thus, the viscosity of the injected solution become higher. The viscosity of solution also increases as the concentration of the polymer in the water increases. Secondly, the rock permeability to water is reduced after the passage of a polymer solution through the rock material. Both effects combine to reduce the value of the water mobility while that for the oil is unaltered.

The option is activated by the keyword POLYMER in the RUNSPEC section. By default the Polymer model is not salt-sensitive and if salt-sensitivity for polymer is required, this can be set by adding the keyword BRINE to the RUNSPEC section. In addition, if the low salinity effect on wettability changing is modeled, LOWSALT keyword also needs to be stated with POLYMER and BRINE keyword in RUNSPEC section.

3.5.1 Polymer effect on fluid viscosity

One criterion that affects the change in the viscosity of the aqueous phase is the mixing type. The mixing parameter data is obligatory and should be provided using the keyword

TLMIXPAR in the PROPS section. The mixing parameter is useful in modeling the degree of segregation between the water and the injected polymer solution. If = 1 then the polymer solution and water are fully mixed in each block. If = 0 the polymer solution is completely segregated from the water. The partially mixed water viscosity is calculated in an analogous manner using the fully mixed polymer viscosity and the pure water viscosity. Accordingly, this study is considered to have fully mixing between polymer and water.

The other criterions are the polymer concentration and salinity presented in the flooding. The combined polymer and low salinity flooding option allows the users to investigate the effect of varying brine concentrations on the efficiency of the polymer flood. The viscosity of a fully mixed polymer solution needs to be entered as a function of the salt concentration. The keywords SALTNODE and PLYVISCS should be used to enter two-dimensional tables for the viscosity of the solution.

Polymer properties used in this study were taken from the researches of Vermolen et al. (2011) and Seungjun et al. (2009). HPAM is defined as the polymer solution. Vermolen suggested the viscosity of 1000 ppm solution of HPAM polymer in a wide range of NaCl concentrations at temperature of 25°C and shear rate of 5.68 S^{-1}. In the meantime, Seungjun gave the viscosity of 2000 ppm solution of HPAM varied the NaCl concentrations at the same conditions. However, since the viscosity of the solutions are presented at room temperature condition, Arrhenius equation is applied for calculating the viscosity at reservoir condition to specify in Eclipse simulation (Sheng, J.J., 2011). Arrhenius equation is shown in EQ.3.14. Moreover, Vermolen also gave the typical activity energy of the HPAM polymer solution calculated from his experiments on the viscosity as a function of temperature and equals to 37.5.

$$\mu_p = A_p \exp\left[\frac{E_a}{RT}\right] \qquad \text{[EQ.3.13]}$$

$$\mu_p = \mu_{p,ref} \exp\left[E_a\left(\frac{1}{T} - \frac{1}{T_{ref}}\right)\right] \qquad \text{[EQ.3.14]}$$

where

A_p	is frequency factor
E_a	is the activity energy of the polymer solution
R	is the universal gas constant
T	is the absolute temperature
$\mu_{p,ref}$	is the viscosity at reference temperature
T_{ref}	is the reference temperature

The solution viscosity with varying of polymer concentration and salinity, is summed in Table.3.9. Fig.3.7 shows the effect of salinity on polymer viscosity. The curves show that when the polymer is not presented in the system, the water viscosity is assumed to be constant. Meanwhile, the salinities over 10000 ppm and under 100 ppm do not influent much, when polymer is injected. The salinity and multiplier values are used in SALTNODE and PLYVISCS keywords.

Table 3. 9 The SALTNODE and PLYVISCS tables (Vermolen, E.C.M., 2011 and Seungjun, L., 2009 and Sheng J.J., 2011)

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

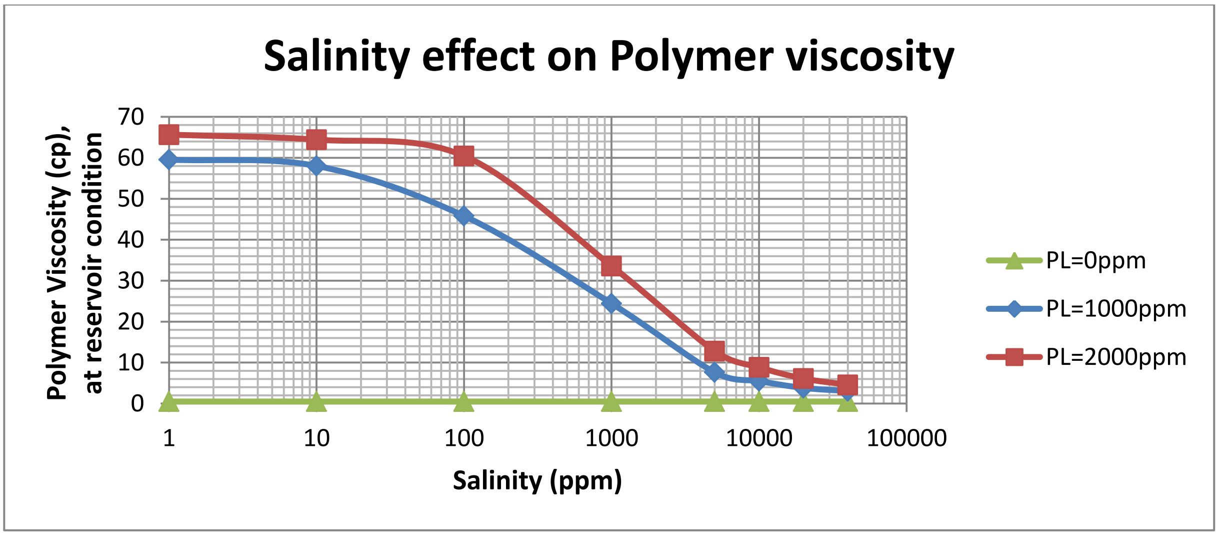


Figure 3. 7 The relationship of salinity effect on polymer viscosity (Vermolen et al., 2011; Seungjun et al., 2009 and Sheng J.J., 2011)

3.5.2 Polymer Adsorption effect

Adsorption is treated as an instantaneous effect in the model. The effect of polymer adsorption is to create a stripped water bank at the leading edge of the slug. Desorption effects may occur as the slug passes. The isotherm adsorption can be specified as either a look-up table of adsorbed polymer as a function of polymer concentration using the PLYADS keyword or by a generic analytical adsorption model using the ADSORP keyword with POLYMER as an argument. Table shows the relationship of polymer concentration adsorbed by rock and polymer concentration that specified in PLYADS keyword.

Table 3. 10 The PLYADS table shows polymer adsorption as function of polymer concentration (Maheshwari Y.K., 2011)

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

3.5.3 Polymer effect on permeability reduction and dead pore volume.

A reduction in the permeability of the rock to the passage of the aqueous phase is caused by the adsorption or polymer on rock surface process. In order to compute the reduction in rock permeability, the rock properties; the dead pore space, residual resistance factor (RRF), rock mass density for each rock type, are required to specify using PLYROCK keyword. The desorption preventing mode can be controlled also in this keyword, resulting the adsorbed polymer concentration may not decrease with time.

The maximum polymer and salt concentrations to be used in calculating the effective fluid component viscosities are entered under the keyword PLYMAX. The polymer concentration is in range of 0 – 0.2%wt or 0 - 2000 ppm and salt concentration is in range of 1 - 40000 ppm.

The mixing region of polymer flooding for each grid cell is specified using the MISCNUM keyword in REGIONS section corresponding with the saturation table. The concentration of polymer and salt for the injection wells can be specified using the WPOLYMER keyword.

3.5.4 The studied cases

As same as the combination of low salinity with alkaline flooding and low salinity with surfactant flooding, there were three main effects studied in the combination of low salinity water flooding and polymer flooding model: effect of polymer concentration in secondary phase recovery, effect of salinity in polymer solution and effect of using high and low salinity in the first phase on polymer flooding in the second phase. Accordingly, the first phase was varied by HS and LS injection before continued by polymer flooding as secondary phase. In addition, since the viscosity of polymer solution depends significantly on polymer concentration and salinity, the polymer solution is prepared at 0.01%wt, 0.03%wt, 0.1%wt and 0.2% in order to find the best polymer concentration effect. Each concentration is mixed with low salinity and high salinity.

The tertiary phase of the combination of low salinity and polymer flooding was still studied to find the best range of polymer injection and the type of tertiary flooding: either HS or LS by continually using the most reasonable case to oil recovery from secondary recovery phase of polymer flooding. Therefore, at last, we should obtain the type of first water flooding phase, concentration of polymer and salinity used in preparing polymer solution, range of polymer flooding and the type of water flooding in the tertiary phase.

3.6 Alkaline-Surfactant-Polymer (ASP) Flooding Model and Properties

The main purpose of ASP flooding is to develop out on the basic effects from single alkaline, surfactant and polymer together. Therefore, oil recovery is enhanced gently by decreasing surface tension, increasing capillary number, enhancing microscopic displacing efficiency, improving mobility ration and increasing macroscopic sweep efficiency. Moreover, when alkaline used in conjunction with surfactant and polymer, the alkaline can reduce the adsorption of both surfactant and polymer on the rock surface, so improving the effectiveness of the surfactant and polymer flooding methods.

There is no special keyword or specific model for ASP in Eclipse-100 because this method is the combination of all single keywords. Consequently, when the single model from alkaline, surfactant, polymer and low salinity water flooding are stated together, the model can simulate and provide the result of the combination automatically. Thus, the ASP model and properties are based on each model that has been stated previously.

3.6.1 The studied cases

In combination of low salinity and ASP flooding, it is divided to alkaline-polymer (AP), alkaline-surfactant (AS) and surfactant-polymer (SP). There were three major studies in each couple of chemical flooding that were effect of one chemical type to the mixed solution, effect of the another chemical type to the solution and the effect of salinity in chemical solution. For example of AP, the first study was effect of alkaline to AP solution by varying low and high alkaline concentration with controlling the same polymer concentration and salinity. In addition, the controlled polymer concentration was also changed to be low and high concentration and in the same way with low and high salinity. It could be said that effect of changing alkaline concentration in high/ low polymer concentration and high/ low salinity. Effect of polymer concentration and salinity in chemical solution were done in similar way.

Unfortunately, there is no study in the combination of low salinity and ASP flooding due to the limit of time. However, we expected that the range of ASP flooding and salinity in tertiary water flooding phase should be similar or in between of each single method.

Chapter 4

Numerical Simulation Results and Discussions

4.1 Base Case

The reference case or the base case *(BC-HS)* is the case with conventional water flooding started from the first day of production through field's production life that is 5 years. High salinity (HS) with salt concentration 40,000 ppm is used as formation water represented high salinity water for whole study. In this study, we assumed formation water has salinity equal to sea water that is 40000 ppm

FOE = Field Efficiency, Oil Recover
FOPR = Field Oil Production rate
FWCT = Field Water-Cut
FPR = Field Pressure

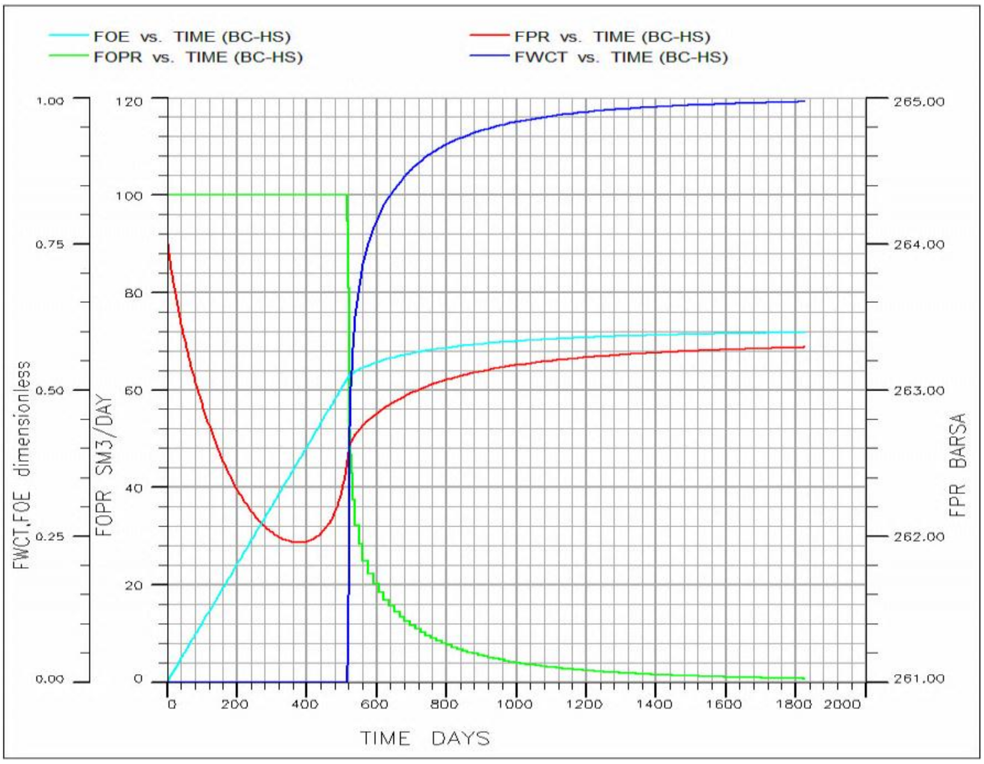


Figure 4. 1 Oil recovery, oil production rate, water-cut and field pressure of the base case

Fig 4.1 shows oil recovery, oil production rate, water-cut and field pressure results of the base case. The HS base case gives approximately 58.8% oil recovery. The oil production rate keeps constant at 100 Sm^3/day as controlling until 513 days of production, and then it goes down rapidly because water reaches breakthrough until becomes 10 Sm^3/day at about 800 days. The rate slows down and keeps constant at a very low rate from 1200 days until the end of production life of the field. Water-cut of the base case has the same trend with production rate but in opposite direction. Although the water injection has injected since the starting of production, field pressure decreases along oil production until 360 days, then builds up suddenly till water breakthrough and keeps slowly increasing through the end of production life. This can be suspected that the HS water flooding takes about 360 days before we can see its effect. After the water breakthrough, the continuous HS flooding tries to maintain the field pressure.

4.2 First Water Flooding Phase and Secondary Recovery Phase

4.2.1 Low Salinity Water Flooding

In low salinity (LS) water flooding, diluted formation water to be salt concentration 1,000 ppm is represented through whole study as Jerauld et al. (2008) suggested that the threshold of salinity concentration that affects to the flooding is range between 1,000 – 7,000 ppm. The scheme of water flooding is as same as HS flooding. Table 4.1 explains short details and recovery of all cases described in LS water flooding part.

Table 4. 1 The short details and recovery of all cases explained in LS flooding

Name	Details	Recovery (%)
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
BC-LS	LS Water Flooding with 1,000 ppm continuing (0-1826 days)	64.9
HS-LS	HS (0-200 days) + LS 1,000 ppm continuing (201-1826 days)	64.3
2-HS-LS	HS (0-320 days) + LS continuing (321-1826 days)	63.9
3-HS-LS	HS (0-513 days) + LS continuing (514-1826 days)	63.5
HS-LS0001	HS (0-200 days) + LS with salinity 1 ppm continuing (201-1826 days)	64.8
HS-LS001	HS (0-200 days) + LS with salinity 10 ppm continuing (201-1826 days)	64.7
HS-LS01	HS (0-200 days) + LS with salinity 100 ppm continuing (201-1826 days)	64.3
HS-LS5	HS (0-200 days) + LS with salinity 5000 ppm continuing (201-1826 days)	62.4
HS-LS10	HS (0-200 days) + LS with salinity 10,000 ppm continuing (201-1826 days)	61.6
HS-LS20	HS (0-200 days) + LS with salinity 20,000 ppm continuing (201-1826 days)	60.7

4.2.1.1 Effect of LS water flooding in first water flooding phase

Fig. 4.2 shows the comparison of the HS base case *(BC-HS)* and LS base case *(BC-LS).* The HS base case gives 58.8% oil recovery while LS base case gives 64.9%, resulting 6.1% incremental cumulative oil recovery. As reservoir oil production rate is controlled at 100 Sm^3/day, both cases maintain their production rates constant until they fall down that means water breakthrough are reached at 513 days for HS case and at 528 days for LS case. After 800 production days, both cases decrease gradually until become almost constant after 1,200 production days. However, the oil production rate of LS case has been higher than HS case. Since their oil production falling, water-cut results correspond to the oil production rate results. Field pressures for both cases have the same trends that are falling from the beginning until obviously effect appearing at about 360 days for HS case and 400 days for LS case. After that, they increase immediately until the water breakthrough point, and then they maintain increasing slightly. The field pressure of LS case has changed more than HS case.

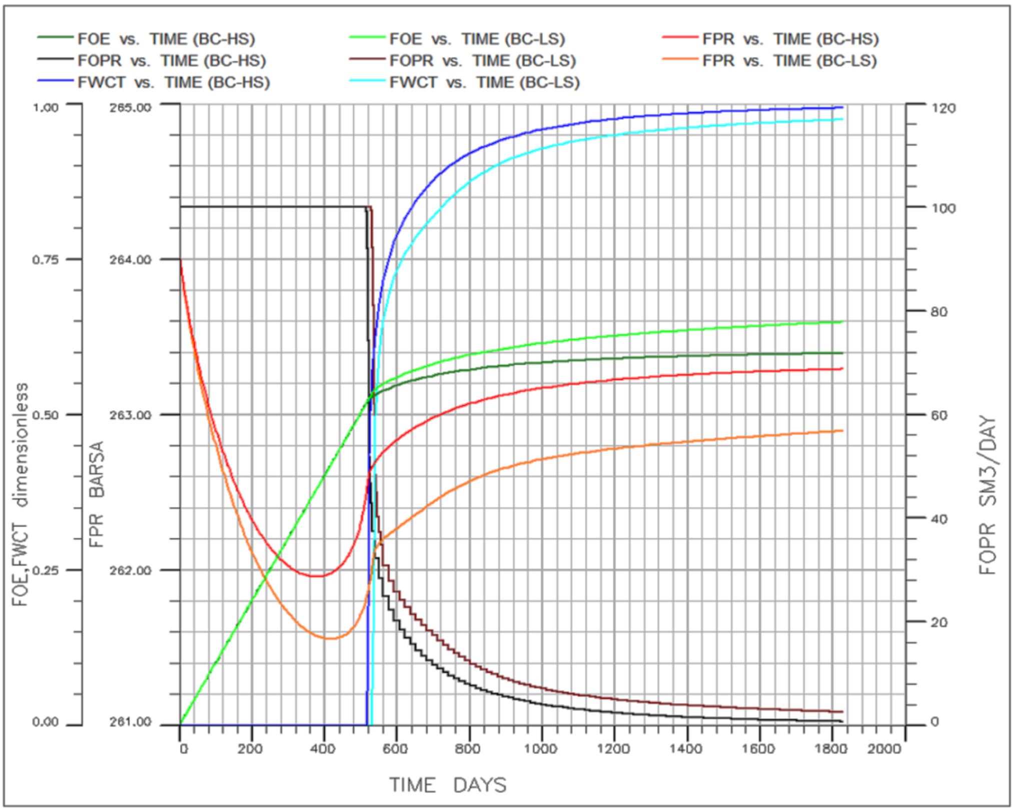


Figure 4. 2 Comparison of results from the HS base case *(BC-HS)* and LS base case *(BC-LS)*

The wettability changing from oil-wet to more water-wet has played a significant role in the effectiveness of LS flooding because of the changing of relative permeability relation in the simulation input data. The field pressure of LS case is a little less than HS flooding case. This is because when wettability becomes more favorable for oil to flow, oil is produced more; hence, field pressure decreases more at the beginning. However, the field pressure still rises up after getting the effect of water flooding. According to oil production rate, when oil can be produced more by effect of LS flooding, water is produced less than the HS flooding case.

4.2.1.2 Effect of timing for the secondary recovery phase

In reality, LS flooding is needed to be concerned about equipment cost and operation cost. To flood by LS for whole production life can cause economic problem, if it does not give incremental oil recovery higher enough. Therefore, LS flooding as secondary or tertiary recovery phase is considered to be more reasonable. This part is focused on interval of primary HS injection and time to start secondary injection by LS water. The day to start secondary phase are selected at 200 days *(HS-LS)*, 320 days *(2-HS-LS)* and 513 days *(3-HS-LS)* after starting production with HS flooding – with 1,625 days, 1,505 days and 1,312 days of LS continuing injection, respectively.

Oil recovery results at the end of production life are 64.3%, 63.98% and 63.4% in order of the first LS injection day after HS flooding at 200 days, 320 days and 513 days. The incremental cumulative oil recovery from HS base case are 5.5%, 5.1% and 4.7% while 0.6%, 1.0% and 1.4% less cumulative oil from LS base case. From Fig. 4.3, the graph shows that the later LS injection, the lower oil recovery as a result from the shorter LS continuing flooding period. However, 200 days and 320 days cases have almost the same oil recovery from the beginning until particularly the end. The 513 days case is not seen clearly different from the base case at the beginning until about 1,100 production days. However, it finally gives almost the same result to the other cases.

Fig 4.4 presents oil production rate and water-cut of these three cases. It can be noticed that LS injection at 200 days gives the earliest effect, hence oil production rate does not drop as much as the other cases from 513 days to 700 days. Then, the rate keeps constant for a while and starts to fall again gradually at 890 days until becoming constant from 1,600 production days. The LS injection at 320 and 513 days have the same trend of oil production rate that fall more than 200 days case after water breakthrough and increase after a period before descend again thereupon. However, the effect of 320 days case can be seen earlier than 500 days case as its earlier LS injection. At the end of production life, oil production rate and water-cut from three cases become almost the same value

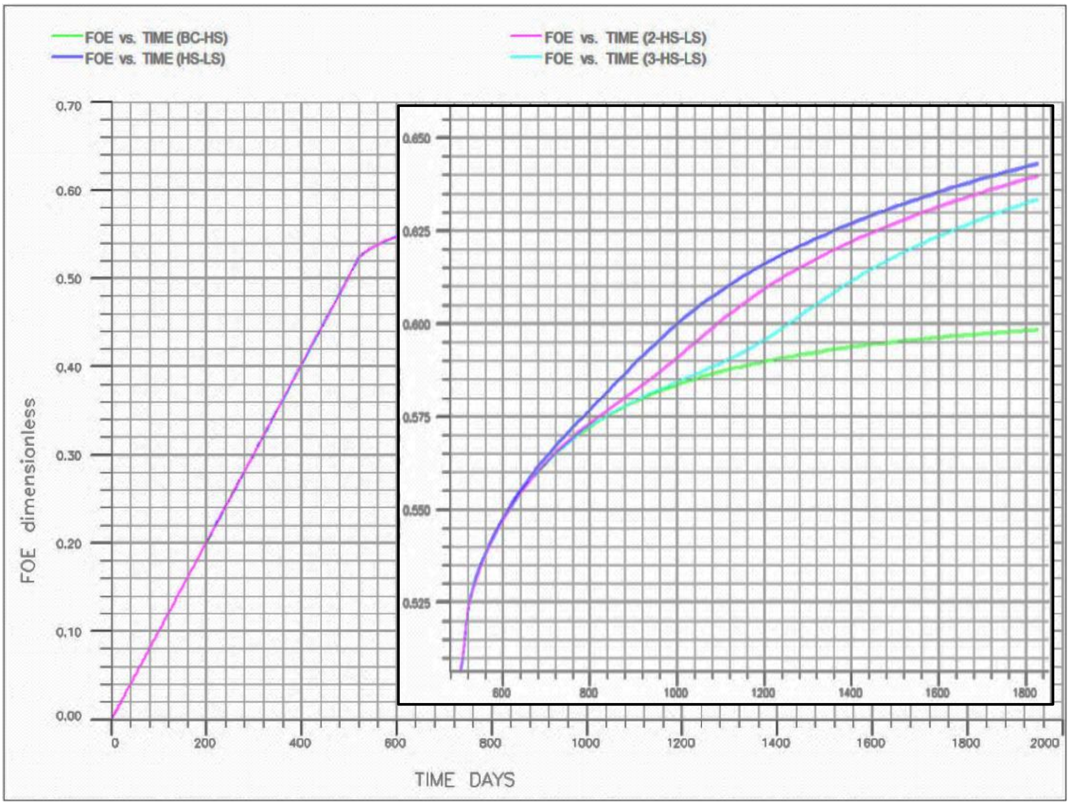


Figure 4. 3 Oil recovery result by varying the LS continuous injection day

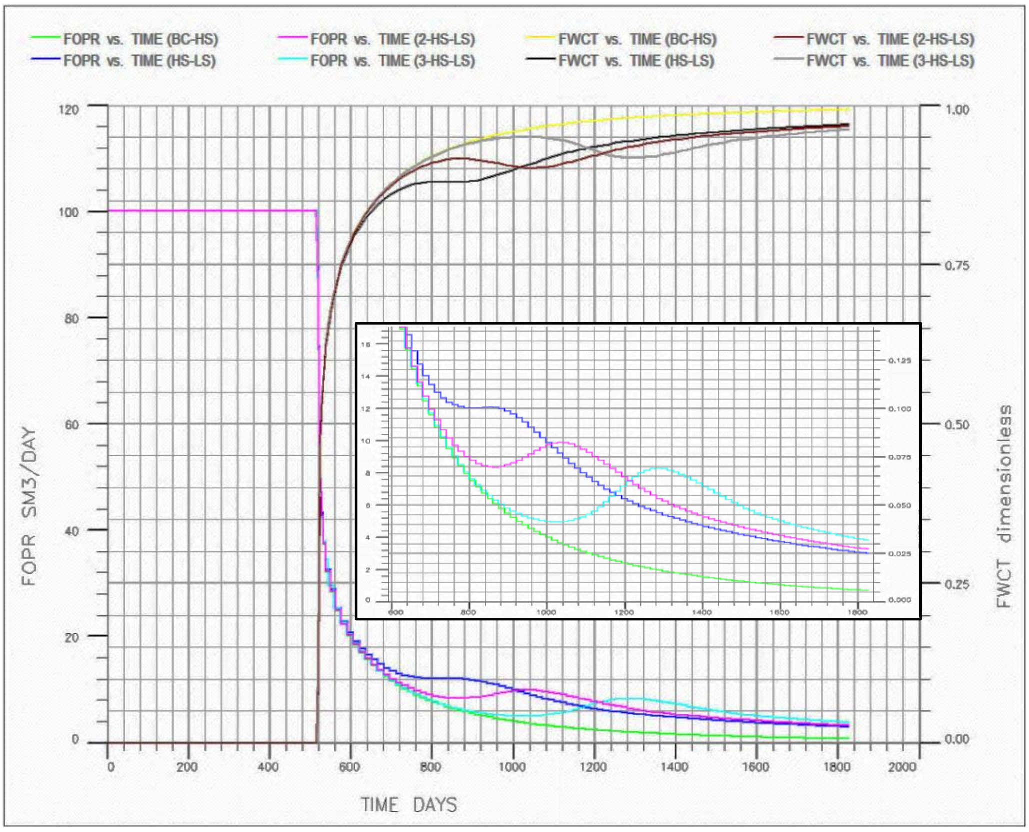


Figure 4. 4 Oil production rate and water-cut results by varying the LS continuous injection day

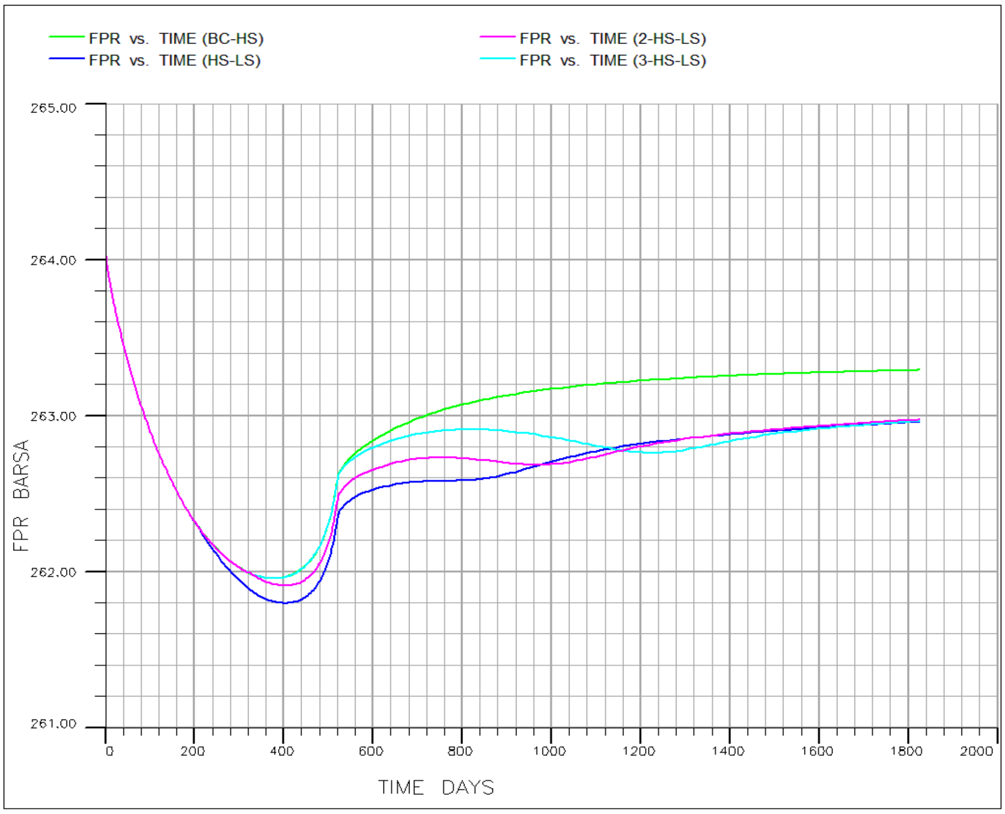


Figure 4. 5 Field pressure result by varying the LS continuous injection day

Wettability changing is still the major reason of these effects. The results are indicated that LS injection needs transition time to reflect the effect and it affects only a short period before reaching breakthrough point of LS flooding and oil production rate becomes constant afterwards. We cannot specify the exactly transition time for the case LS injected at 200 days and 320 days because the transition can be accounted starting before the water breakthrough. But from the case LS injected at 513 days, which is water breakthrough point, the transition time of this case is approximately 500 days. It means that LS flooding needs about 500 days after injection to cause oil production rate increase obviously. However, we can calculate the time from starting LS injection to the time when oil production rate start to decrease obviously, which is approximately the length of LS flooding effect. Table 4.2 shows the length of LS flooding effect compared by the starting day of LS flooding.

Table 4. 2 The length of LS flooding effect compared by the starting day of LS flooding

Case	Starting LS injection (days)	Oil rate start decreasing (days)	Effect Interval (days)
HS-LS	200	890	690
2-HS-LS	320	1060	740
3-HS-LS	513	1310	797

From the table, it means that the effect takes place longer when injection later. This can be explained by using oil production rate graph. When LS is injected earlier, the effect starts earlier, resulting oil after water breakthrough still keep production at the higher rate, thus oil should be produced fast and reach the residual oil saturation earlier as well. The later LS injection case has lower oil production rate at the beginning after water breakthrough, and then increases again but still lower rate comparing to the earlier injection. So, it takes longer time to get into residual oil saturation.

In case of continuing LS injection until specified 5 years production life, the starting LS injection at 513 days is seemed to be the best case because it gives oil recovery almost same as the earlier injection cases. However, oil companies would not continue producing at this low production rate but would consider stopping secondary phase and starting tertiary phase instead. In this case, the injection at 513 days is too late to get the effect because oil production rate has not been constant certainly at end of production life. Although the 200 days and 320 days produce almost the same oil recovery at 5 years production, we can stop LS injection as secondary phase and continued by tertiary phase in case of starting injection at 200 days earlier than 320 days.

The sooner we stop secondary phase, the sooner we can start tertiary phase. Therefore, the following cases through this study will start the secondary recovery phase after 200 production days. The range of secondary phase and timing to start tertiary phase will be found in further discussion.

4.2.1.3 Effect of salinity in the secondary recovery phase

Since core flooding results have shown that incremental oil recovery varies with the salinity of the brine. However, no incremental oil is recovered in over certain salinity threshold, and similarly under the other salinity threshold. Jerauld et al. (2008) summarized that to achieve low salinity effect; the injected concentration must be below 25% of the salinity of the connate water, with approximate values of 1,000 to 7,000 ppm for the lower and upper salinity threshold.

This part is studied about the effect of varying salinity in LS flooding as secondary recovery phase. From the previous discussion, the HS injection is followed by LS injection after 200 days of production and continued until the end of production life that is 5 years. The salinities of brine is varied at the amount of 1 ppm *(HS-LS0001)*, 10 ppm *(HS-LS001)*, 100 ppm *(HS-LS01)*, 1000 ppm *(HS-LS)*, 5000 ppm *(HS-LS5)*, 10000 ppm *(HS-LS10)* and 20000 ppm *(HS-LS20)*. The HS flooding at salinity 40000 ppm *(BC-HS)* is the reference case.

Fig.4.6 and Fig.4.7 present oil recovery and oil production rate for salinity in brine sensitivity. Oil can be produced higher when salinities become lower. Oil recovery for the cases of 1 ppm, 10 ppm, 100 ppm, 1000 ppm, 5000 ppm, 10000 ppm and 20000 ppm are 64.8%, 64.7%, 64.3%, 64.3%, 62.4%, 61.6% and 60.7%, respectively, compared to HS base case at 58.8%. Both figures show a big gap between salinity 1000 ppm and 5000 ppm that are expected to be the lower and the upper thresholds, meanwhile, the results of salinity below 1000 ppm do not give much different from the lower threshold as same as the results of salinity above 5000 ppm do with the upper threshold. Moreover, we can see a range of increasing in oil production rate, if salinity is equal or lower than 1000 ppm. This indicates the procedure of connate water banking and wettability changing phase - when salinity is low enough, the process takes about 500 days to demonstrate the noticeable effect.

Fig.4.9 summarizes the salinity in brine sensitivity on LS water flooding as secondary recovery phase. It cans be concluded that there are significant difference oil recovery, 3.2% between lower and upper thresholds, while there is not big difference between each result, which has salinity apart from the thresholds. Considering economically, the results assure that we can use 40000 ppm salinity in brine representing HS flooding and 1000 ppm for LS flooding.

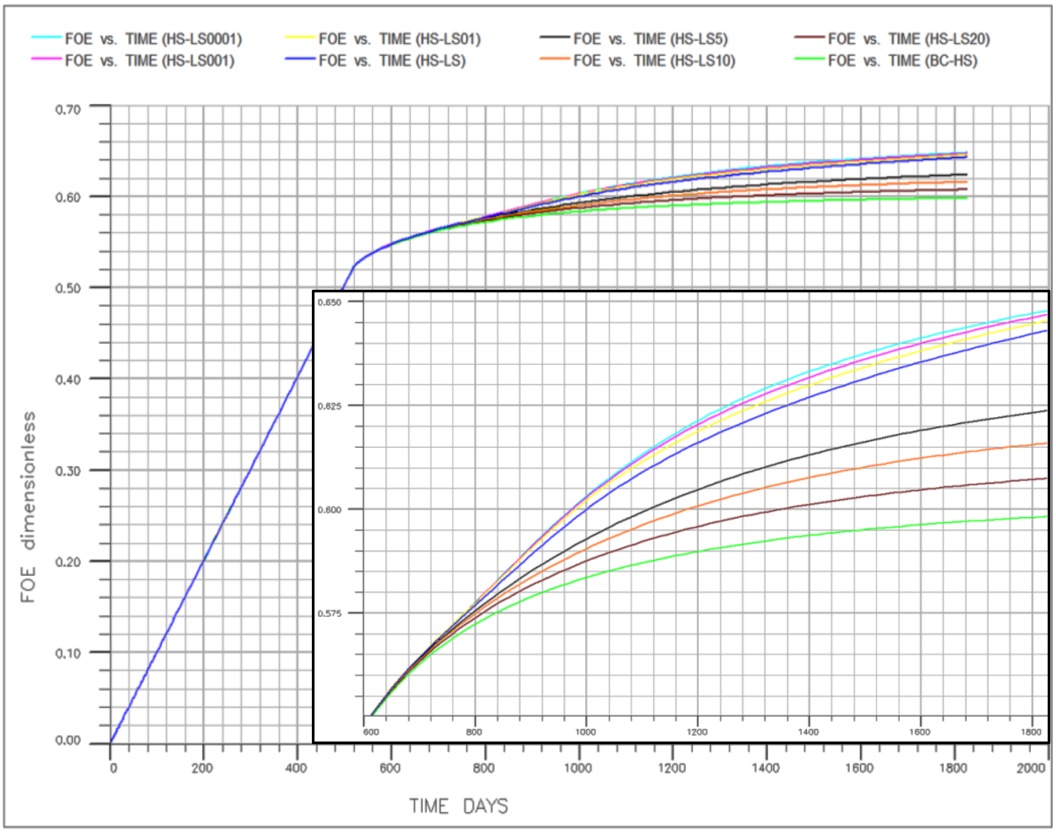


Figure 4. 6 Oil recovery result from salinity in brine sensitivity

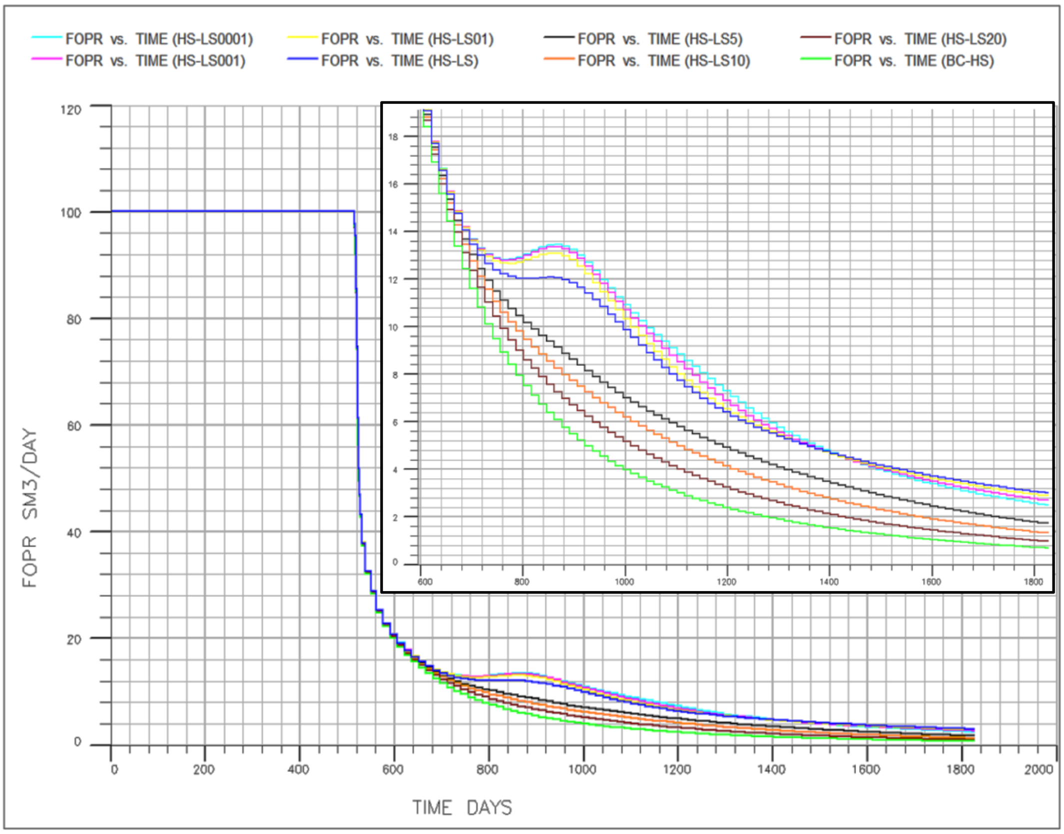


Figure 4. 7 Oil production rate result from salinity in brine sensitivity

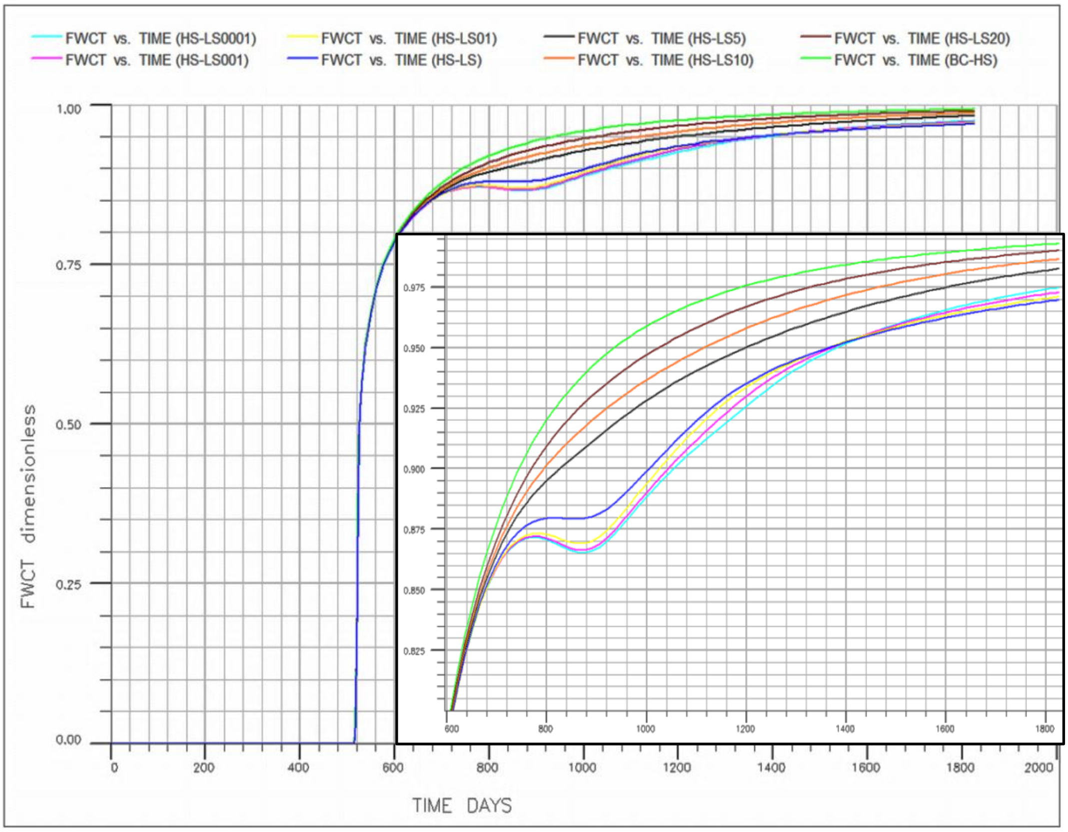


Figure 4. 8 Water- cut result from salinity in brine sensitivity

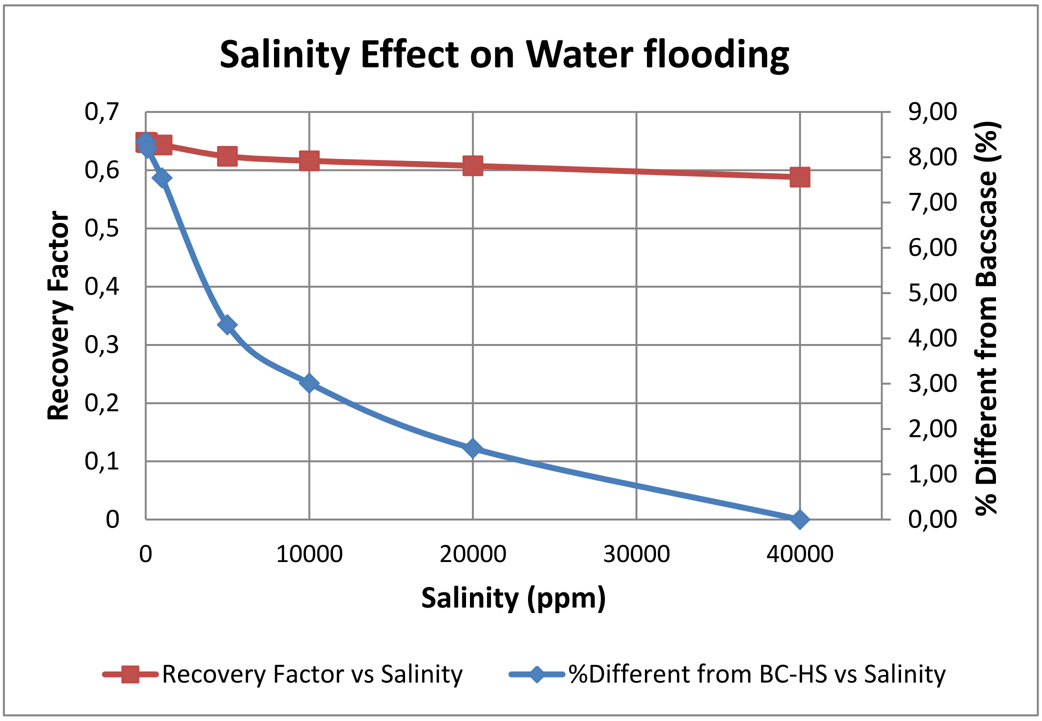


Figure 4. 9 Summary of the salinity in brine sensitivity on LS water flooding as secondary recovery phase result

4.2.1.4 Summary

From low salinity water flooding, based on the properties used in this study, the continuous LS flooding gives higher oil recovery about 6.1% compared to HS flooding base case. Regarding LS injection in secondary recovery phase, as the earlier starting continuous flooding, the higher oil recovery. Moreover, with the earlier starting secondary flooding, we can stop it earlier and follow by tertiary flooding. Decreasing brine salinity can cause more oil production but only in the threshold range between 1,000 ppm- 5,000 ppm. Therefore, using 40,000 ppm salinity in HS flooding as primary phase for 200 days and continuing with 1,000 ppm salinity in LS flooding as secondary flooding *(HS-LS)* is the most reasonable case for the tertiary recovery phase study.

4.2.2 Combination of Low Salinity Water Flooding and Alkaline Flooding

This part is studied on using alkaline flooding as secondary recovery phase. It is divided to be 3 parts; effect of alkaline concentration in secondary injection, effect of salinity in alkaline solution mixture and effect of using high and low salinity as the first water injection phase to alkaline flooding. From the previous discussion, salinity at 40000 ppm is represented HS flooding and 1000 ppm is stood for LS flooding. This definition is also used for salt concentration in alkaline solution. Alkaline concentration is specified at 1.5%wt and 3%wt for low case and high case, respectively. The primary recovery phase has been varied between HS flooding and LS flooding, while the secondary phase, which is started after 200 days of production and continued until the end of production life, is either the mixture of alkaline concentration 1.5%wt or 3%wt with salinity 1000ppm and 40000ppm. The short details and recovery result of cases described in the combination of LS flooding and alkaline flooding is shown in Table 4.3.

Table 4. 3 The short details and recovery results of cases described in the combination of LS flooding and alkaline flooding

Name	Details	Recovery (%)
HS-A15SAL1	HS (200 days) + Alkaline 1.5%wt with salinity 1000 ppm (201-1826 days)	64.3
HS-A15SAL40	HS (200 days) + Alkaline 1.5%wt with salinity 40000 ppm (201-1826 days)	59.8
HS-A30SAL1	HS (200 days) + Alkaline 3%wt with salinity 1000 ppm (201-1826 days)	687
HS-A30SAL40	HS (200 days) + Alkaline 3%wt with salinity 40000 ppm (201-1826 days)	67.6
LS-A15SAL1	LS (200 days) + Alkaline 1.5%wt with salinity 1000 ppm (201-1826 days)	64.9
LS-A15SAL40	LS (200 days) + Alkaline 1.5%wt with salinity 40000 ppm (201-1826 days)	61.1
LS-A30SAL1	LS (200 days) + Alkaline 3%wt with salinity 1000 ppm (201-1826 days)	69.4
LS-A30SAL40	LS (200 days) + Alkaline 3%wt with salinity 1000 ppm (201-1826 days)	68.2
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
BC-LS	LS Water Flooding with 1,000 ppm continuing (0-1826 days)	64.9

Fig.4.10, Fig.4.11 and Fig.4.12 present the oil recovery, oil production rate and water-cut profile of all cases compared to HS base case. The oil recovery results show in a pair of HS and LS with the same alkaline concentration and salinity in the secondary phase. LS give higher oil recovery than HS flooding. The alkaline solution prepared by 3%wt alkaline and 1000 ppm affects highest oil recovery, followed by 3%wt alkaline and 40000 ppm, 1.5%wt alkaline and 1000 ppm and 1.5%wt alkaline and 40000 ppm, respectively. The incremental cumulative oil production from the HS base case is in order of 10.6% *(LS-A30SAL1)*, 9.9% *(HS-A30SAL1)*, 9.4% *(LS-A30SAL40)*, 8.8% *(HS-A30SAL40)*, 6.1% *(LS-A15SAL1)*, 5.5% *(HS-A15SAL1)*, 2.3% *(LS-A15SAL40)* and only 1.0% *(HS-A15SAL40)*

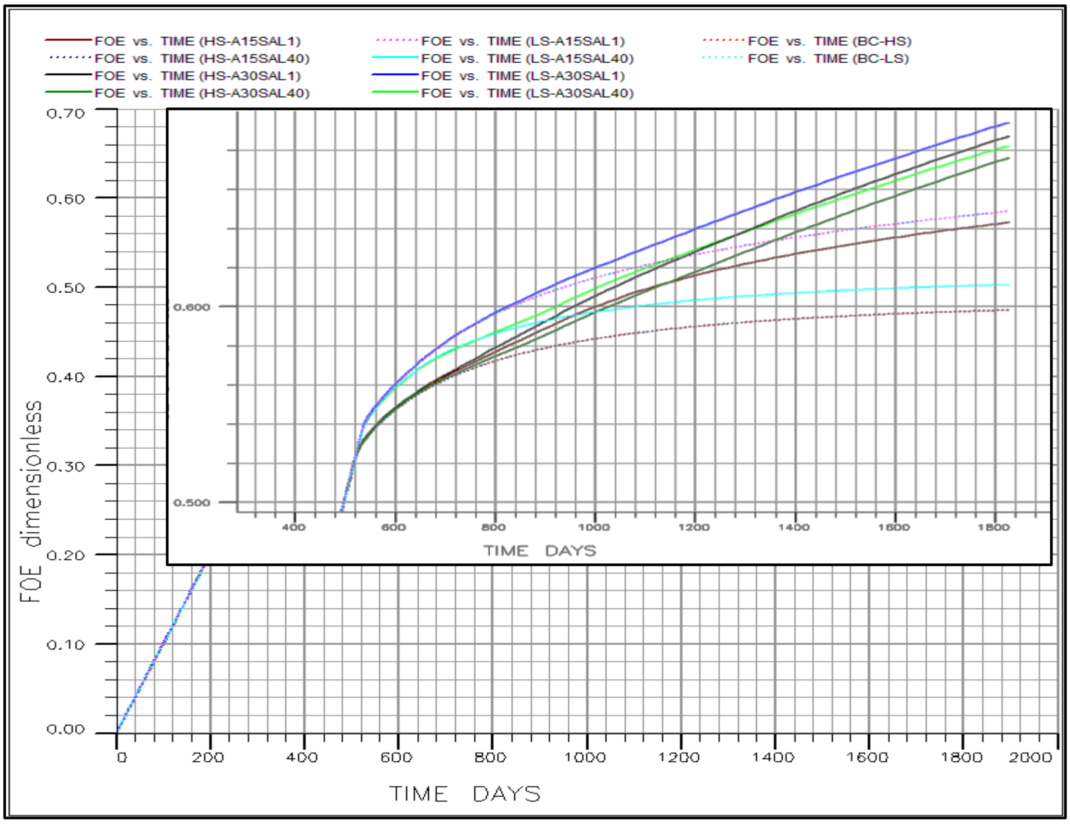


Figure 4. 10 The oil recovery of the combination of LS and alkaline flooding

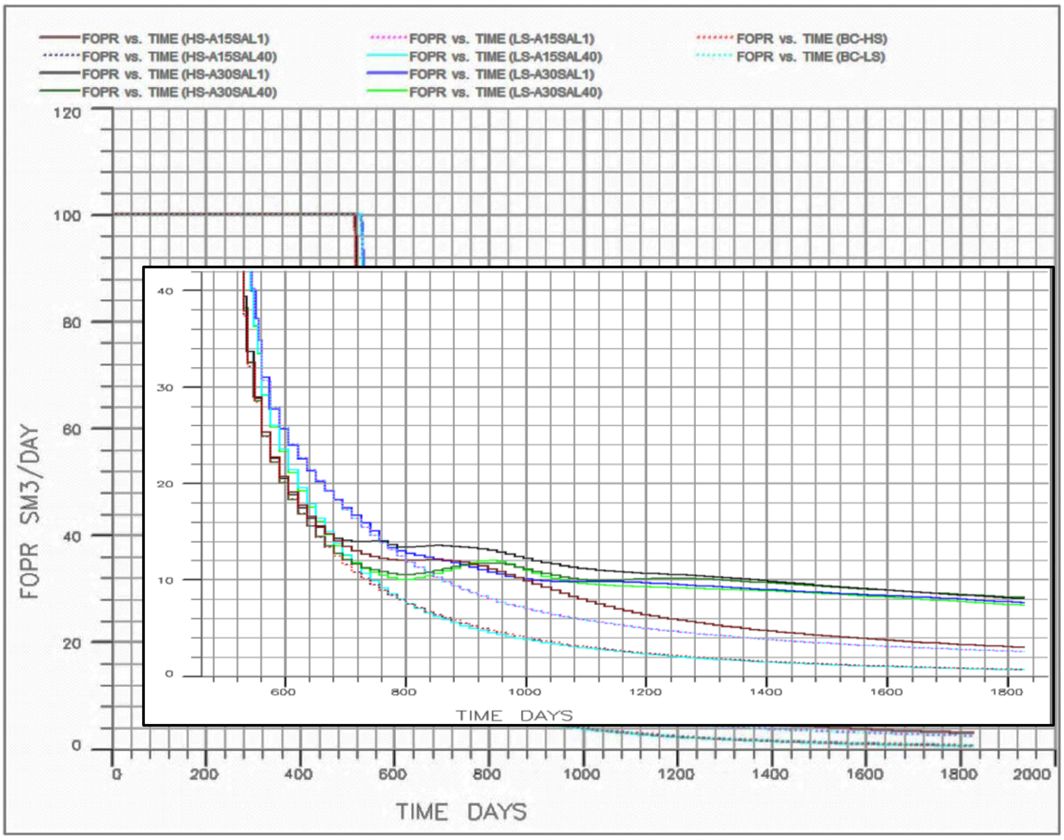


Figure 4. 11 The oil production rate of the combination of LS and alkaline flooding

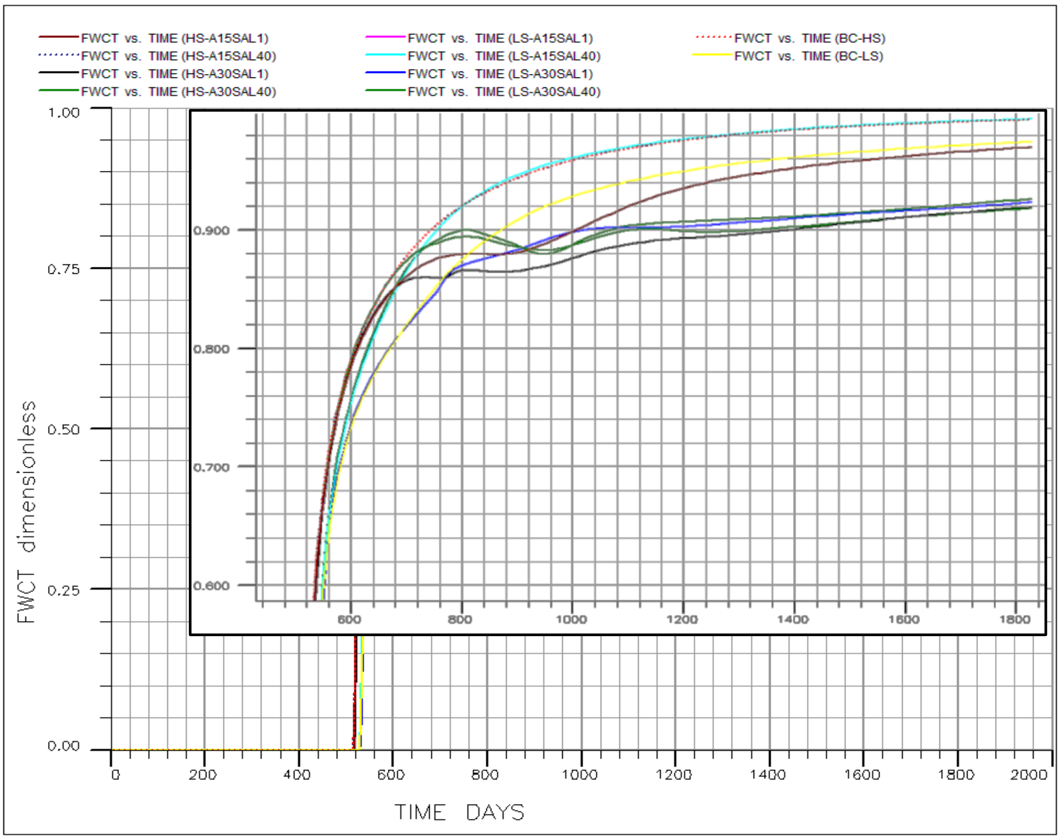


Figure 4. 12 The water-cut of the combination of LS and alkaline flooding

4.2.2.1 Effect of Alkaline concentration

Fig.4.13 shows the comparison of alkaline concentration when control the same primary phase and salinity in the alkaline solution. “HS/SAL1000” is stood for HS as first water flooding phase and salinity 1000 ppm in the alkaline solution. The results can be seen clearly that, in all cases, the oil recovery is increased as the alkaline concentration increases, thus, oil recovery of 3%wt alkaline is higher than the HS base case and LS base case, correspondingly, more than 1.5%wt as well.

This is due to the interaction between oil and alkaline solution, resulting in the creation of in-situ W/O emulsion (Liu Q., 2006) However, there is not big significant effect when the alkaline concentration is 1.5%, particularly combination with high salinity in the solution is even worse, compared to HS and LS base case. This is ascribed to the fact that the interaction between the oil and the injected alkaline solution is not strong enough to create the in-situ emulsification. Meanwhile, when the alkaline concentration is 3.0%, interactions between the oil and alkaline solution become strong enough and consequently improve oil recovery.

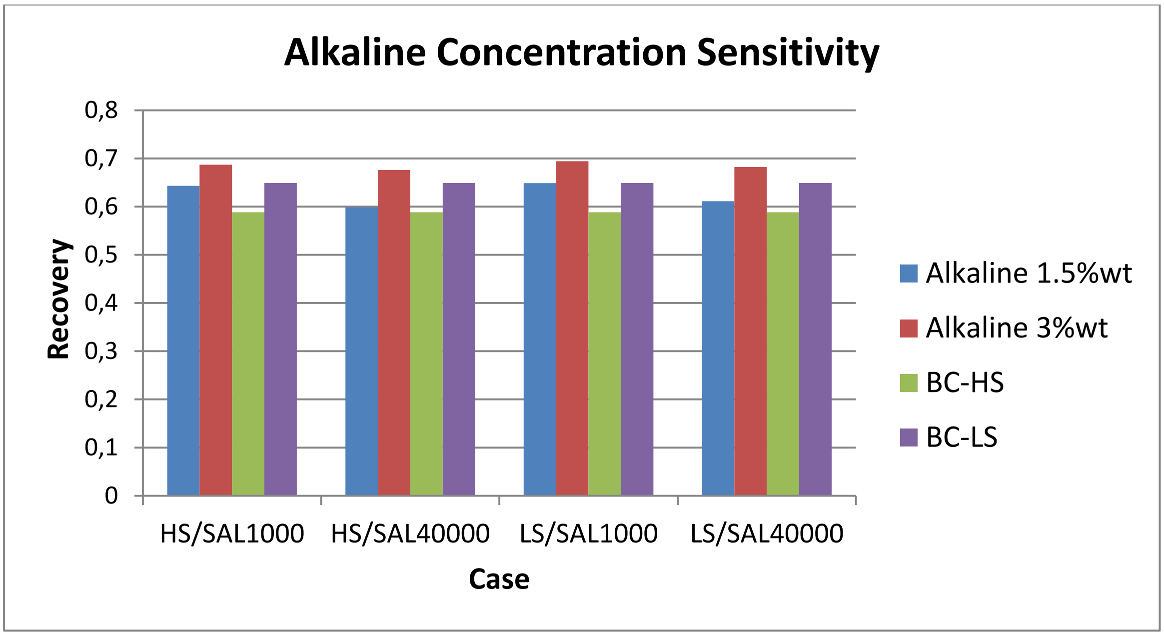


Figure 4. 13 The comparison of alkaline concentration when controlling the same first water flooding phase and salinity in the alkaline solution (BC-HS and BC-LS are the base case for comparison)

4.2.2.2 Effect of Salinity in alkaline solution

Fig.4.14 displays the comparison of salinity in alkaline solution when control the same first water flooding phase and the alkaline concentration. “HS/A1.5%” is represented HS as first water flooding phase and 1.5%wt alkaline concentration. It can be observed that oil recovery decrease in a small amount when salinity increase in alkaline concentration 3%wt while they decrease significantly when salinity increase in alkaline concentration 1.5%wt. Moreover, oil recovery of the cases alkaline concentration 1.5%wt and salinity 40000 ppm are almost the same and even less compared to HS and LS base case, respectively.

These results can be explained that when the brine salinity increase, the diffusion of the in-situ surfactants into the aqueous phase declines and more surfactants remain at the oil/water interface, which is favorable for the formation of water drops inside the oil phase. However, when the brine salinity is too high, some honeycomb oil blocks appear and the improvement in oil recovery is strongly limited (Jijiang, 2012).

From the previous effect discussion that alkaline concentration 1.5% is not strong enough to improve oil recovery, besides, alkaline concentration influences to recovery more powerful than salinity in alkaline solution. Thereby, in case of high salinity in low alkaline concentration mixture, the effect of IFT reduction and wettability changing impact about or less than the only wettability changing effect of HS or LS flooding. Simultaneously, high salinity in high alkaline concentration solution still involves to higher oil recovery than the only HS or LS flooding.

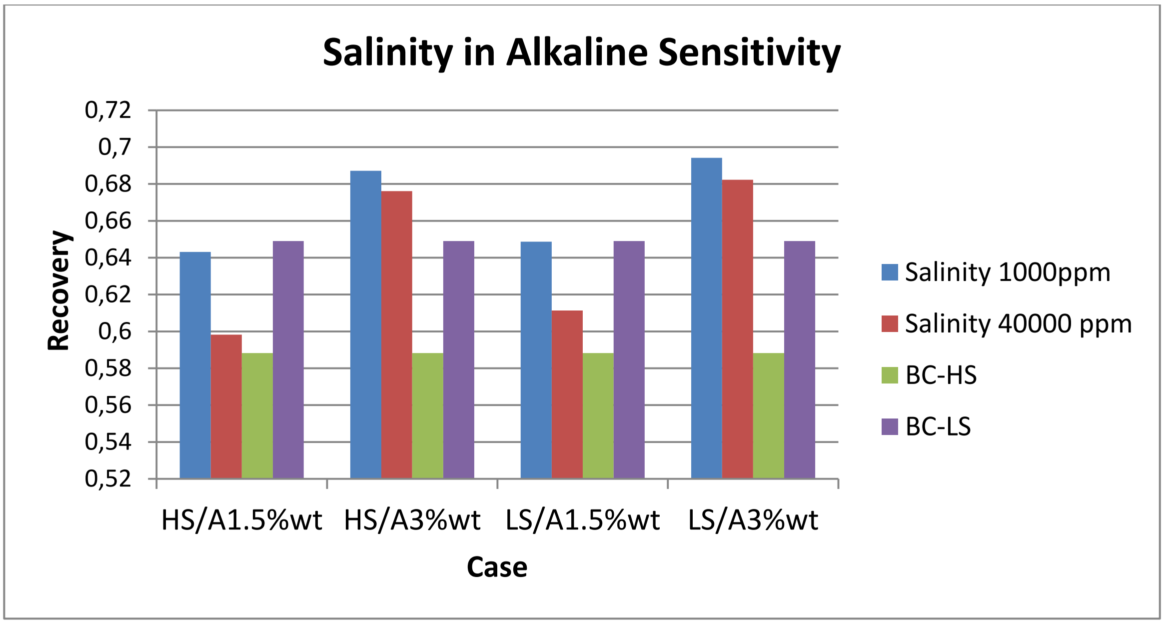


Figure 4. 14 The comparison of salinity in alkaline solution when controlling the same first water flooding phase and the alkaline concentration (BC-HS and BC-LS are the base case for comparison)

4.2.2.3 Effect of Salinity in first water flooding phase

The comparison between HS and LS flooding in the first water flooding phase when controlling the same salinity and alkaline concentration solution is shown in Fig.4.15 “A1.5%SAL1000” is represented 1.5%wt alkaline concentration with 1000 ppm salt concentration. It can be noticed that oil recovery is higher in using LS flooding (1000ppm) in first water flooding phase. However, there is only small difference between HS and LS in all cases. This can be resulted of wettability changing to become more water-wet in the first water flooding phase.

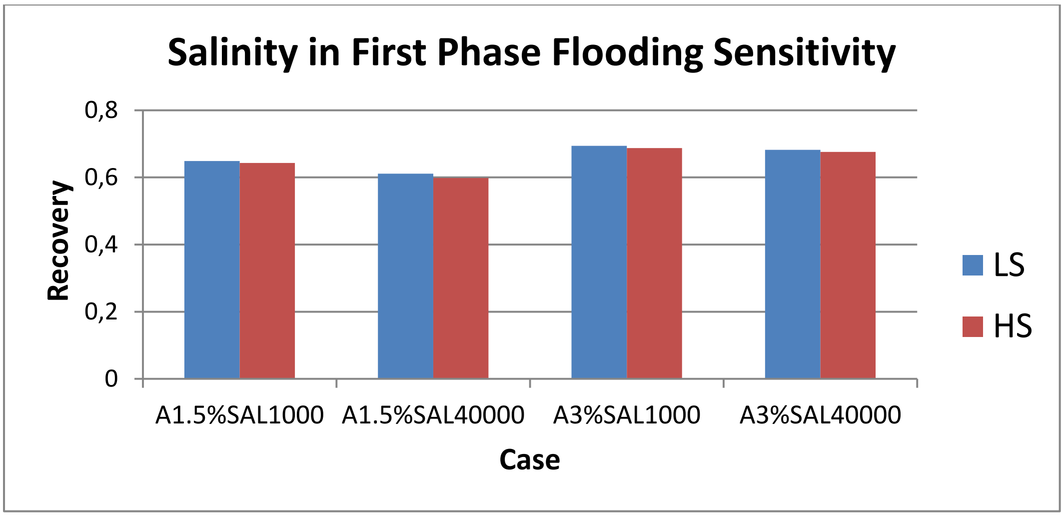


Figure 4. 15 The comparison between HS and LS flooding in the first water flooding phase when controlling the same salinity and alkaline concentration solution

4.2.2.4 Summary

From combination of LS and alkaline flooding, based on alkaline properties used in this study, the oil recovery increases as alkaline concentration increases while salinity in alkaline solution decrease. However, alkaline concentration 1.5%wt is not high enough to affect higher oil recovery. All results are stronger influenced from effect of alkaline concentration that is IFT reduction than effect of salinity that shift wettability become more water-wet. Consequently, using HS or LS flooding in the first recovery phase do not give important difference. From Fig.4.15, the oil recovery decrease in order of LS/HS-A3%SAL1000, LS/HS-A3%SAL40000, LS/HS-A1.5%SAL1000 and LS/HS-A1.5%SAL40000.

Mainly, the continuous injection of alkaline solution is not used in real case but slug of alkaline solution is used instead. In order to study the comparison of continuous alkaline injection and the slug injection and also the effect of HS and LS flooding in the tertiary phase after alkaline injection in the secondary phase, HS-A30SAL1 case, which is HS flooding in first water flooding phase and followed by 3%wt alkaline with 1000ppm salinity solution, is selected for further discussion.

4.2.3 Combination of Low Salinity Water Flooding and Surfactant Flooding

This part is focused on using surfactant flooding as secondary recovery phase. It is divided to be 3 parts as same as in alkaline flooding part that are effect of surfactant concentration in secondary injection, effect of salinity in surfactant solution mixture and effect of using high and low salinity as the first water flooding phase to surfactant flooding. HS flooding is meant salinity at 40000 ppm and is used for LS flooding 1000 ppm. Salt concentration in surfactant solution has also the same definition. Surfactant concentration is specified at 1%wt and 2%wt for low case and high case, respectively. Time to start secondary recovery flooding is at the same time to the other types of flooding that is after 200 days of production and continued injection until end of production life.

The first water flooding phase has 2 types; HS flooding and LS flooding. For the secondary phase, surfactant solution is prepared from surfactant concentration 1%wt and 2%wt with salinity 1000ppm and 40000ppm. The short details and recovery result of cases described in the combination of LS flooding and surfactant flooding is shown in Table 4.4.

Table 4. 4 The short details and recovery results of cases described in the combination of LS flooding and surfactant flooding

Name	Details	Recovery (%)
HS-S10SAL1	HS (200 days) + Surfactant 1%wt/ salinity 1000 ppm (201-1826 days)	70
HS-S10SAL40	HS (200 days) + Surfactant 1%wt/ salinity 40000 ppm (201-1826 days)	68.2
HS-S20SAL1	HS (200 days) + Surfactant 2%wt/ salinity 1000 ppm (201-1826 days)	71.1
HS-S20SAL40	HS (200 days) + Surfactant 2%wt/ salinity 40000 ppm (201-1826 days)	68.4
LS-S10SAL1	LS (200 days) + Surfactant 1%wt/ salinity 1000 ppm (201-1826 days)	70
LS-S10SAL40	LS (200 days) + Surfactant 1%wt/ salinity 40000 ppm (201-1826 days)	68.3
LS-S20SAL1	LS (200 days) + Surfactant 2%wt/ salinity 1000 ppm (201-1826 days)	71.5
LS-S20SAL40	LS (200 days) + Surfactant 2%wt/ salinity 40000 ppm (201-1826 days)	68.8
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
BC-LS	LS Water Flooding with 1,000 ppm continuing (0-1826 days)	64.9

The oil recovery of all cases compared to HS and LS base case are shown in Fig.4.16. The results also present in a pair of HS and LS with the same surfactant concentration and salinity in the secondary phase by LS give higher oil recovery than HS flooding. The highest oil recovery case is surfactant 2%wt and 1000 ppm salinity, followed by 1%wt surfactant and 1000 ppm, 2%wt surfactant and 40000 ppm and 1%wt surfactant and 40000 ppm, respectively. The surfactant flooding results quite high incremental cumulative oil production from the HS base case: 12.7% (LS-S20SAL1), 12.3% (HS-S20SAL1), 11.2% (LS-S10SAL1), 11.2% (HS-S10SAL1), 10.0% (LS-S20SAL40), 9.6% (HS-S20SAL40), 9.5% (LS-S10SAL40) and only 9.4% (HS-S10SAL40).

The overall reason is that surfactants are adsorbed at fluid/fluid interface and can reduce IFT between two liquids. The lower IFT would lead to a higher capillary number, and a higher capillary number would make the capillary-trapped residual oil remaining after water flooding recovered resulting in a lower residual oil saturation. (Emegwalu, C.C., 2009). However, salinity gives much effect in this study and assures that optimum salinity is very important in surfactant flooding.

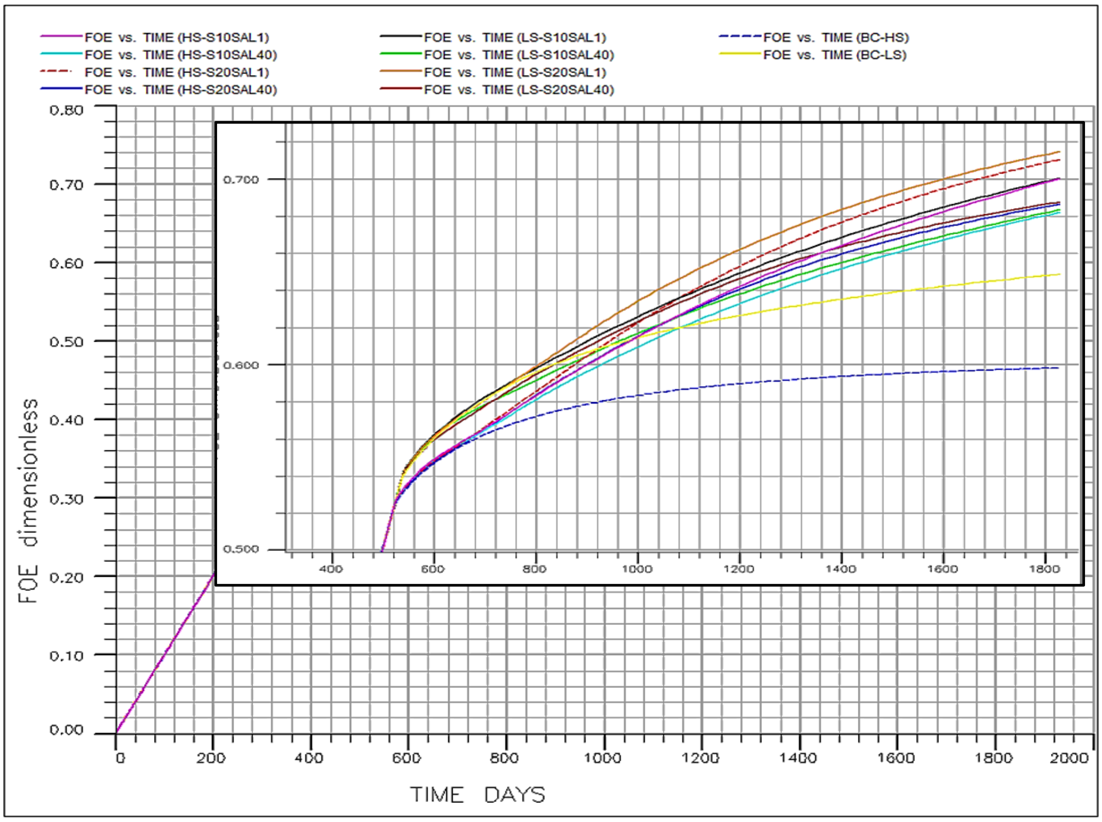


Figure 4. 16 The oil recovery of the combination of LS and Surfactant flooding

Fig.4.17 and Fig.4.18 show oil production rate and water-cut ratio results. For HS flooding as first water flooding phase case, oil is kept producing at constant reservoir volume rate until 513 days, when the water breakthrough occurs. Then, oil rate decreases dramatically until about 630 days that it increases because of surfactant effect up to 800 days before it starts to decrease again through the end of production life. For LS flooding as first water flooding phase case, the results have the same trend but are delayed by reason of LS flooding effect. The changing points are approximately 530 days – 700 days – 850 days through end of production life. This can be demonstrated that surfactant does not affect to the system immediately and its effect last for a certain surfactant concentration even though in the continuous surfactant flooding.

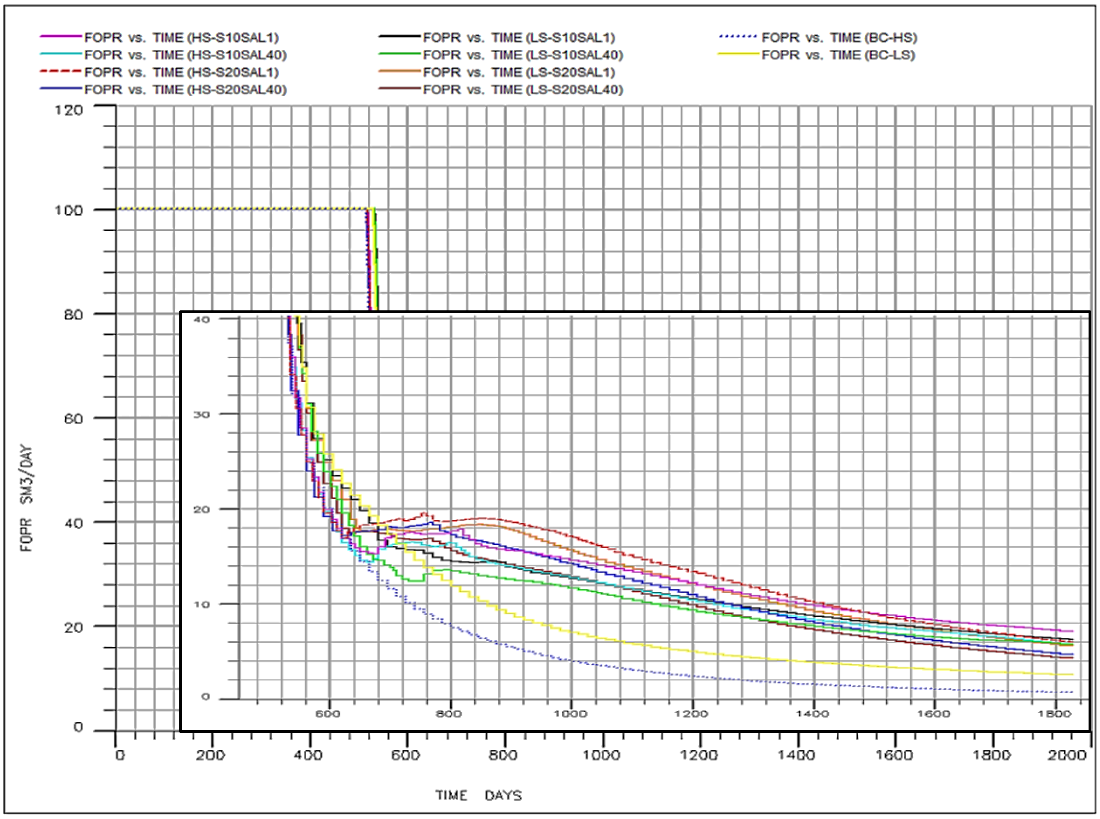


Figure 4. 17 The oil production rate of the combination of LS and Surfactant flooding

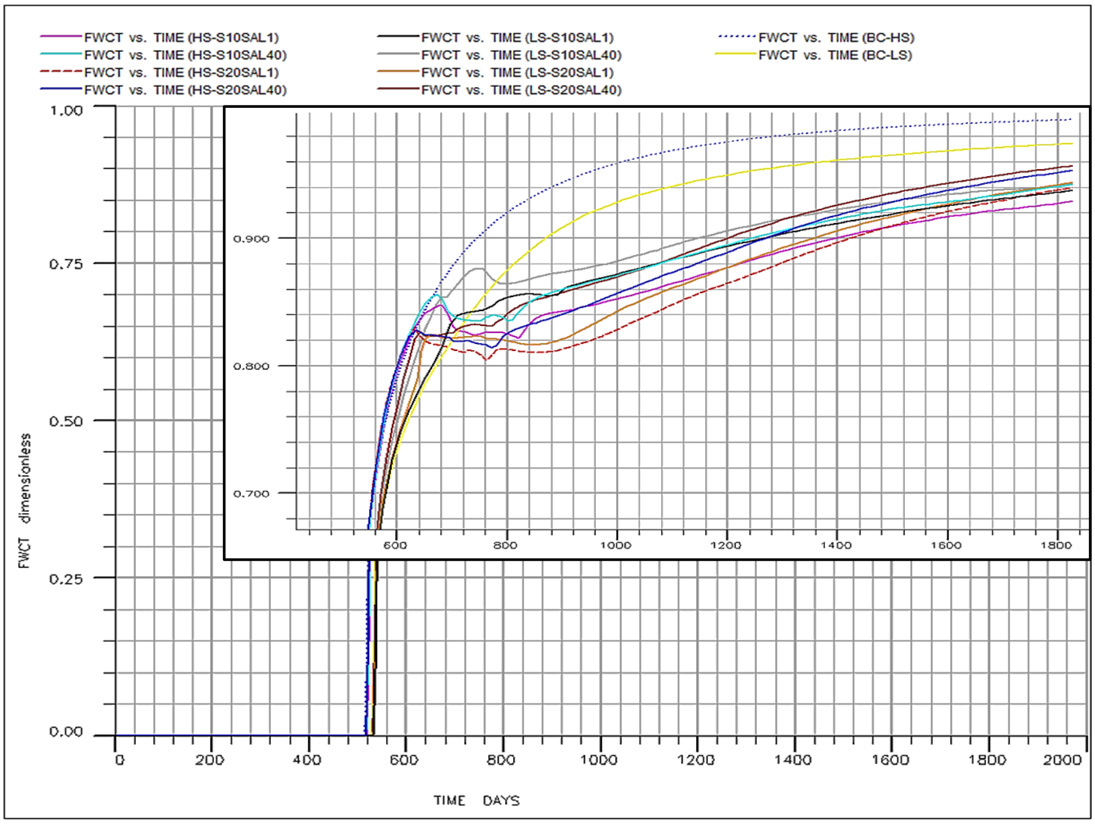


Figure 4. 18 The water-cut of the combination of LS and Surfactant flooding

Less water is produced for both surfactant cases, particularly comparing to HS and LS base case, because oil is being produced instead. So the water cut goes down after the surfactant starting to pay off and go up again when less oil is present.

4.2.3.1 Effect of surfactant concentration

The comparison of surfactant concentration when keep the same primary phase and salinity in the surfactant solution is shown in Fig.4.19. “HS/SAL1000” is represented for HS as primary phase and salinity 1000 ppm in the surfactant solution. The results can be indicated clearly that, as surfactant concentration increases, the oil recovery is increased. However, the difference of oil recovery from each compared cases is approximately only 1-2%.

Hirasaki (1982) proposed that if the surfactant concentration is below the critical micelle concentration (CMC), the IFT changes extensively with the concentration of the surfactant. In the other side, when the surfactant concentration is above the CMC, the IFT stays constant. This can applied to our results that 2%wt concentration is over CMC and that causes the recovery of all cases with surfactant concentration 2%wt are not largely different from 1%wt; surfactant concentration 1%wt is expected to be more reasonable.

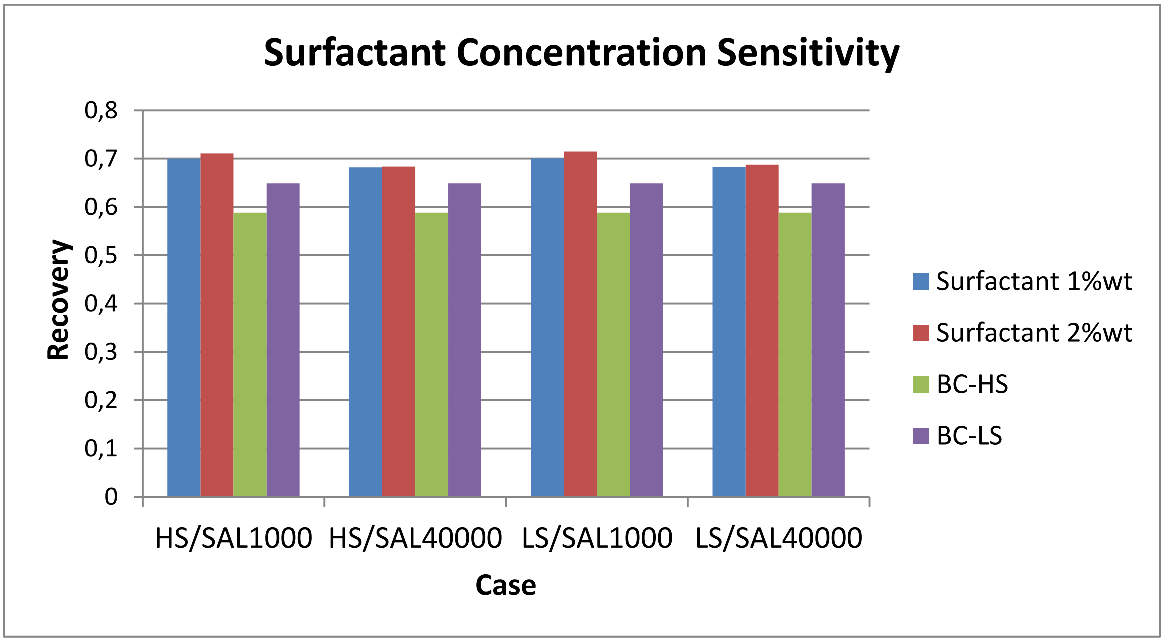


Figure 4.19 The comparison of surfactant concentration when keeping the same first water flooding and salinity in the surfactant solution (BC-HS and BC-LS are the base cases for comparison)

4.2.3.2 Effect of salinity in surfactant solution

The comparison of salinity in surfactant solution when controlling the same first water flooding phase and the surfactant concentration is displayed Fig.4.20. “HS/S1%wt” is represented for HS as first water flooding phase and 1.0%wt surfactant concentration. It can be noticed that increasing salinity in surfactant solution gives negative effect to oil recovery. Oil recovery increases about 3-4%, when increasing salinity from 1000 ppm to 40000 ppm. One key point is that recovery from all cases with 1000 ppm salinity are higher than the highest recovery from cases with 40000 ppm, regardless surfactant concentration, so apart from LS/HS-S20SAL1 cases, which are the best cases, LS/HS-S10SAL1 cases are better than LS/HS-S20SAL40 cases. It means that salinity plays the important role to surfactant flooding and even more when the surfactant concentration is over CMC.

Hirasaki (1980) explained this result that as salinity increases, Type II- progresses to Type III and to Type II+ phase behavior. The optimum salinity in Type III phase is where IFT is minimum. The experiments of Glover et al. (1979) was proposed that in low salinity condition or Type II- system is better than Type II+ system because much of the surfactant retention could be caused by phase trapping in Type II+, while much of this retained surfactant could be remobilized with a low-salinity drive. Gupta and Trushenski (1979) also pointed out that in a Type II+ environment, in the presence of dispersion, not only did the peak surfactant concentration decrease, but the location lagged behind with increased dispersion. These two factors resulted in a lower oil recovery and delay in oil production. From our results, it can be summarized that salinity 1000 ppm could be either optimum salinity in this system or Type II- that involves better oil recovery than salinity 40000ppm that should be Type II+.

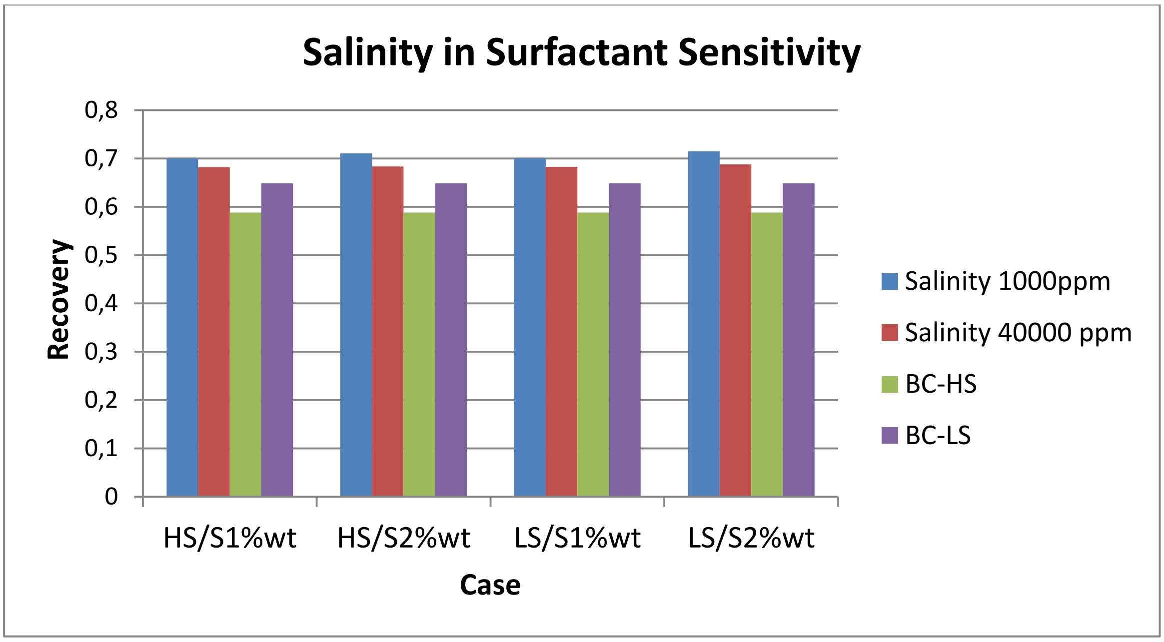


Figure 4.20 The comparison of salinity in surfactant solution when controlling same first water flooding phase and the surfactant concentration (BC-HS and BC-LS are the base case for comparison)

4.2.3.3 Effect of salinity in primary recovery phase

The comparison between HS and LS flooding in the first water flooding phase when controlling the same salinity and surfactant concentration solution is presented in Fig.4.21. “S1%SAL1000” is represented for 1%wt surfactant concentration with 1000 ppm salt concentration. The figure shows that change of salinity in first water flooding phase does not influent to oil recovery.

However, LS flooding in first water flooding phase still results to change wettability becoming more water-wet as we can see in delaying water breakthrough. In the same meaning, surfactant flooding has more power to involve to higher oil recovery than wettability changing effect in primary water flooding.

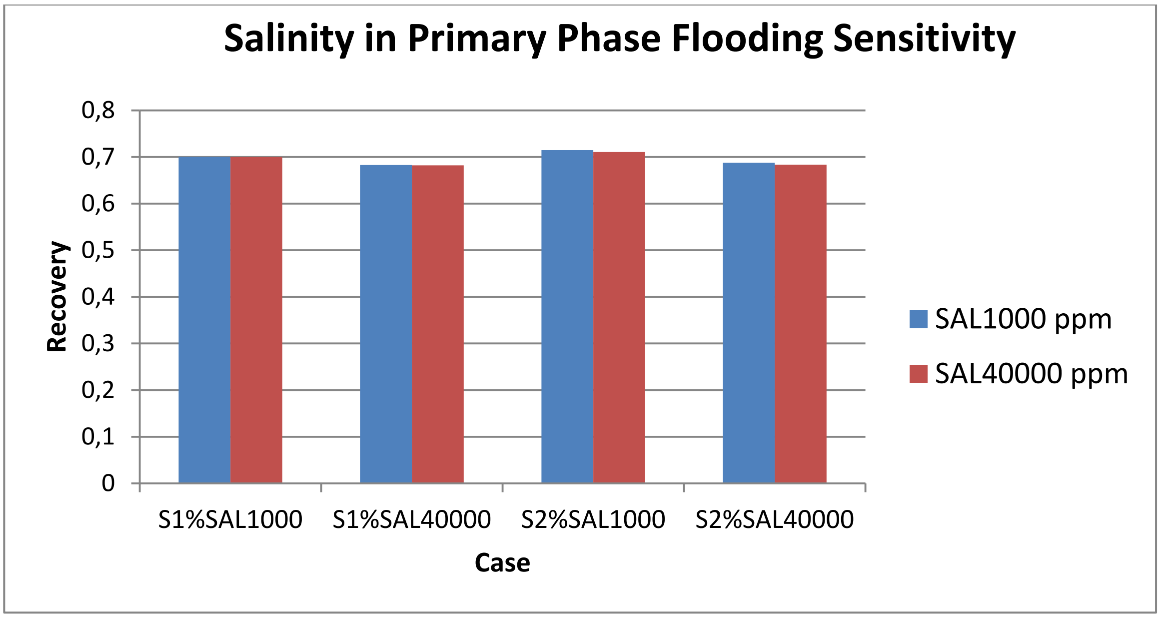


Figure 4. 21 The comparison between HS and LS flooding in the first water flooding phase when controlling the same salinity and surfactant concentration solution

4.2.3.4 Summary

From combination of LS and surfactant flooding, based on surfactant properties used in this study, increasing surfactant concentration can improve oil recovery because of IFT reduction but 2%wt surfactant concentration is too much because there is not big difference recovery from 1%wt concentration. Decreasing salinity in surfactant solution can also affects producing more oil and salinity 1000 ppm is supposed to be either optimum salinity or Type II- in this system. As surfactant concentration 2%wt is too high, the effect of salinity in surfactant solution is stronger than effect of surfactant itself and effect of wettability changing in first water flooding phase. In summary of oil recovery result, the oil recovery decrease in order of LS/HS-S2%SAL1000, LS/HS-S1%SAL1000, LS/HS-S2%SAL40000 and LS/HS-S1%SAL40000.

Considering economics, tertiary injection phase after surfactant injection in the secondary phase will be discuss further. HS-S10SAL1 case which are HS flooding in first water flooding phase and followed by 1%wt surfactant concentration with 1000ppm salinity solution, are investigated.

4.2.4 Combination of Low Salinity Water Flooding and Polymer Flooding

Using polymer flooding as secondary recovery phase is studied in this topic. In the same way as the precious discussion, effect of polymer concentration in secondary injection, effect of salinity in polymer solution mixture and effect of using high and low salinity as the first water flooding phase to polymer flooding are presented. Salinity 40000 ppm and 1000 ppm are meant HS and LS flooding, respectively, as same definition as salt concentration in polymer solution. Polymer concentration is varied between 0.01%wt (100 ppm), 0.03%wt (300 ppm), 0.1%wt (1000 ppm) and 0.2%wt (2000 ppm) in order for low case and high case. The injection starts is after 200 days of production and continues till end of production life.

The first water flooding recovery phase has 2 types; HS flooding and LS flooding. For the secondary phase, surfactant solution is prepared from polymer concentration 0.1%wt and 0.2%wt with salinity 1000ppm and 40000ppm. Table 4.5 summarizes the short detail and recovery result of cases from the combination of LS flooding and polymer.

Table 4. 5 The short detail and recovery result of cases from the combination of LS flooding and polymer

Name	Details	Recovery (%)
HS-P01SAL1	HS (200 days) + Polymer 0.01%wt (100ppm) with salinity 1000 ppm (201-1826 days)	67.9
HS-P01SAL40	HS (200 days) + Polymer 0.01%wt (100ppm) with salinity 40000 ppm (201-1826 days)	60.1
HS-P03SAL1	HS (200 days) + Polymer 0.03%wt (300ppm) with salinity 1000 ppm (201-1826 days)	68.1
HS-P03SAL40	HS (200 days) + Polymer 0.03%wt (300ppm) with salinity 40000 ppm (201-1826 days)	60.2
HS-P1SAL1	HS (200 days) + Polymer 0.1%wt (1000ppm) with salinity 1000 ppm (201-1826 days)	68.1
HS-P1SAL40	HS (200 days) + Polymer 0.1%wt (1000ppm) with salinity 40000 ppm (201-1826 days)	60.2
HS-P2SAL1	HS (200 days) + Polymer 0.2%wt (2000ppm) with salinity 1000 ppm (201-1826 days)	66.9
HS-P2SAL40	HS (200 days) + Polymer 0.2%wt (2000ppm) with salinity 40000 ppm (201-1826 days)	60.2
LS-P01SAL1	LS (200 days) + Polymer 0.01%wt (100ppm) with salinity 1000 ppm (201-1826 days)	68.0
LS-P01SAL40	LS (200 days) + Polymer 0.01%wt (100ppm) with salinity 40000 ppm (201-1826 days)	61.7
LS-P03SAL1	LS (200 days) + Polymer 0.03%wt (300ppm) with salinity 1000 ppm (201-1826 days)	68.2
LS-P03SAL40	LS (200 days) + Polymer 0.03%wt (300ppm) with salinity 40000 ppm (201-1826 days)	62.4
LS-P1SAL1	LS (200 days) + Polymer 0.1%wt (1000ppm) with salinity 1000 ppm (201-1826 days)	68.1
LS-P1SAL40	LS (200 days) + Polymer 0.1%wt (1000ppm) with salinity 40000 ppm (201-1826 days)	63.3
LS-P2SAL1	LS (200 days) + Polymer 0.2%wt (2000ppm) with salinity 1000 ppm (201-1826 days)	67.8
LS-P2SAL40	LS (200 days) + Polymer 0.2%wt (2000ppm) with salinity 40000 ppm (201-1826 days)	63.8
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
BC-LS	LS Water Flooding with 1,000 ppm continuing (0-1826 days)	64.9

The oil recovery of the cases using HS and LS flooding as first water flooding phase are shown in Fig.4.22 and Fig.4.23, respectively. It can be noticed that both water types have the same oil recovery trend that there is a big separation between the cases using salinity 1000 ppm and the cases using 40000 ppm in the polymer solution. Comparing with the HS base case, all cases, which have HS in the first water flooding phase and brine 40000 ppm in polymer solution, have the final oil recovery almost same as HS base case even the recoveries are higher at the beginning. For the cases applying LS in the first water flooding phase and brine 40000 ppm in polymer solution, oil recoveries result a little higher than HS base case from the water breakthrough until the end of production. The oil recovery of cases with HS flooding and salinity 1000 ppm in polymer solution are not much different from each other and the cases with LS flooding and salinity 1000 ppm do the same as well.

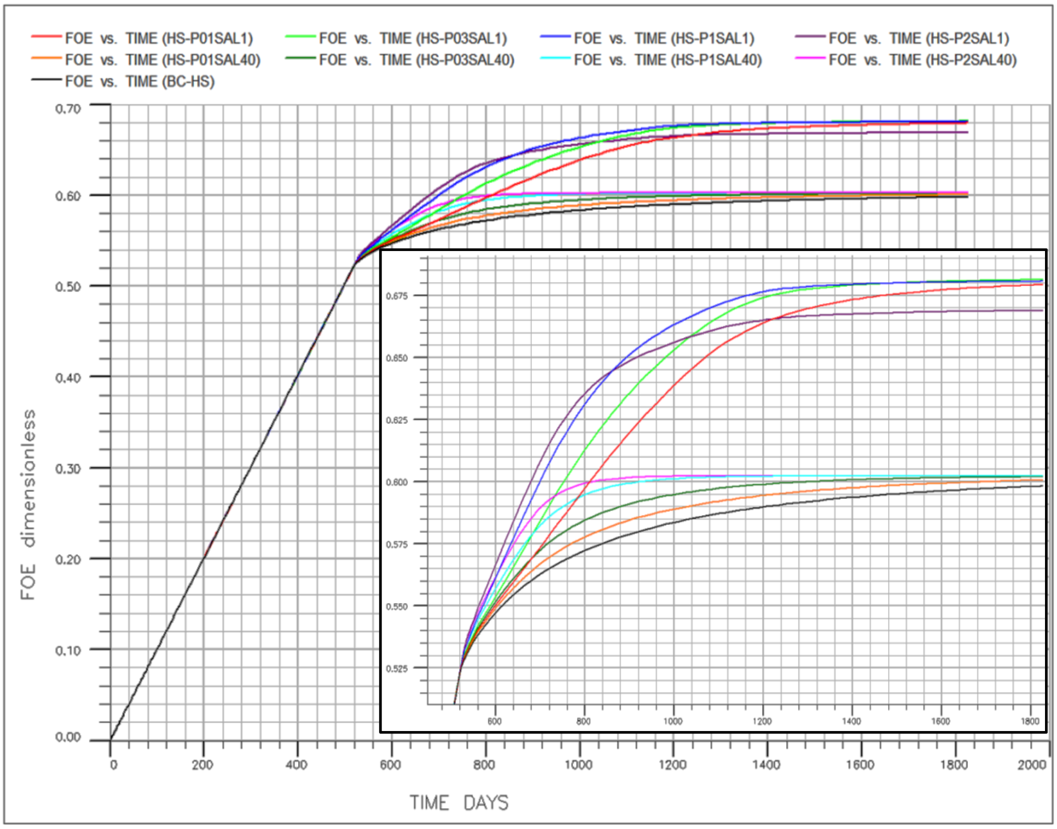


Figure 4. 22 The oil recovery of the cases using HS flooding as first water flooding and polymer flooding in the secondary phase

Fig.4.24 and Fig.4.25 show oil production rate results of the cases that have HS and LS flooding, respectively, in the first water flooding phase. Both of the graphs present the same order of oil rate profiles but the lengths of their profiles are different. The oil rate profiles of the cases with HS in first water flooding phase decrease slightly, while the cases with LS decrease rapidly; thus, oil rates of LS flooding stop producing earlier than using HS flooding in the first phase. However, both of them have a better rate than HS base case for a period after water breakthrough point

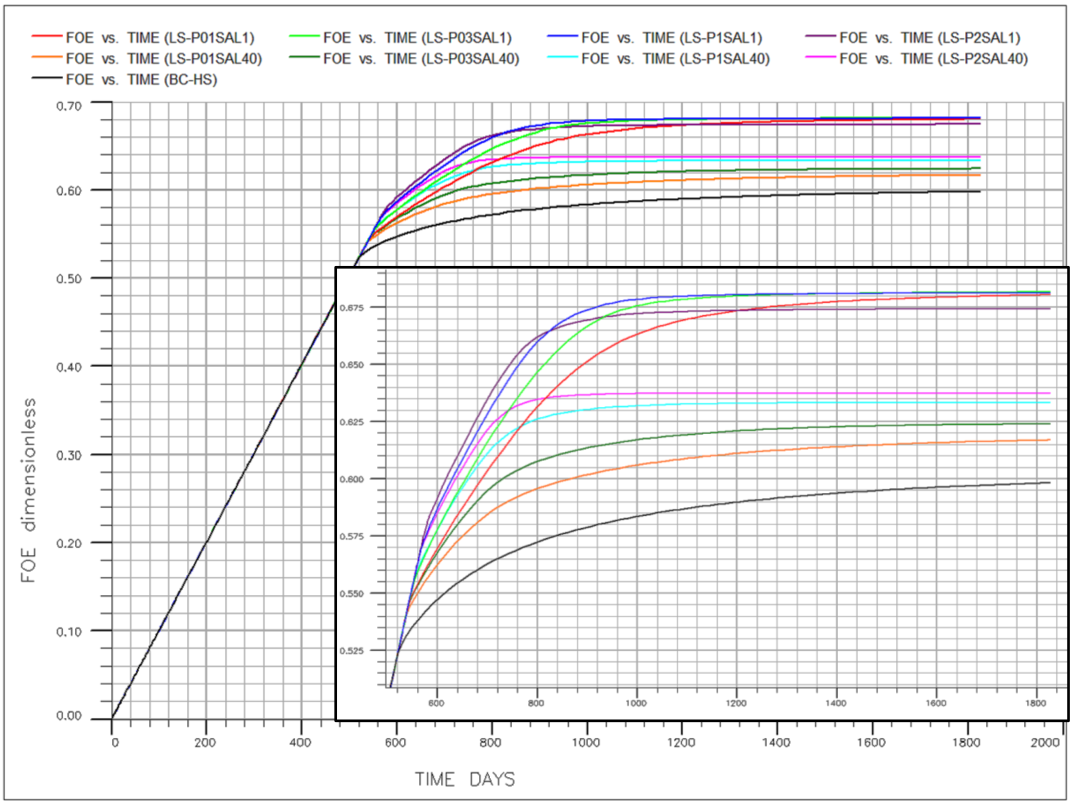


Figure 4. 23 The oil recovery of the cases using LS flooding as first water flooding and polymer flooding in the secondary phase

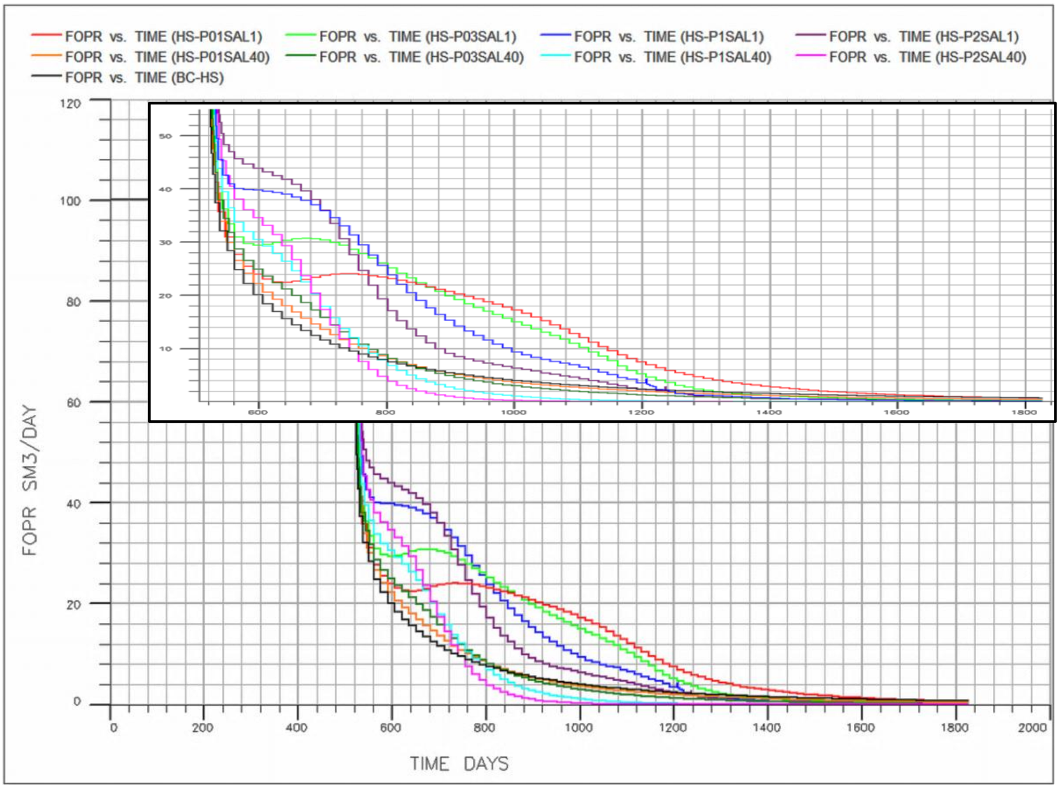


Figure 4. 24 Oil production rate of the cases that have HS flooding in first water flooding phase and polymer flooding in the secondary phase

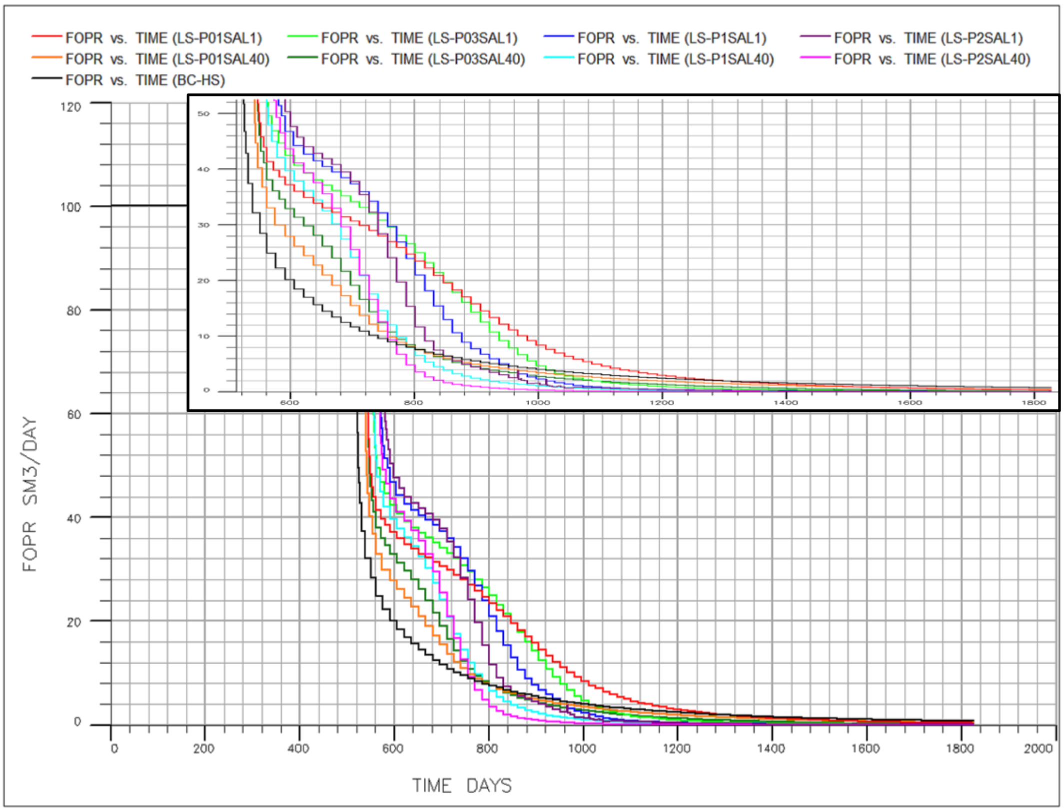


Figure 4. 25 Oil production rate of the cases that have LS flooding in the first water flooding and polymer flooding in the secondary phase

The water-cut of HS flooding and LS flooding, respectively, in the first water flooding phase and polymer solution in the secondary phase are shown in Fig.4.26 and Fig.4.27. The water-cut results are consistent with oil production rate. There is water breakthrough at 513 days, when using HS flooding as first water flooding phase, while the water breakthrough of cases using LS flooding is a bit later. The water-cut reach the maximum quite early, when the polymer concentration is high.

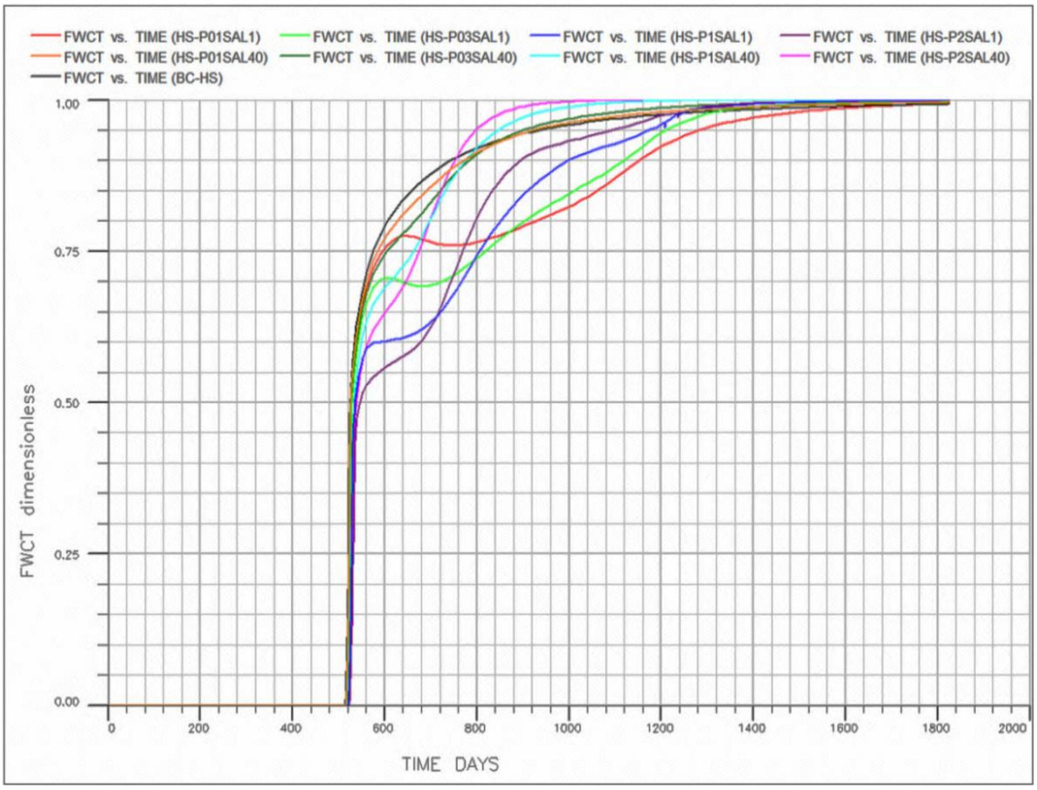


Figure 4. 26 The water-cut of HS flooding in the first water flooding phase and polymer flooding in the secondary phase

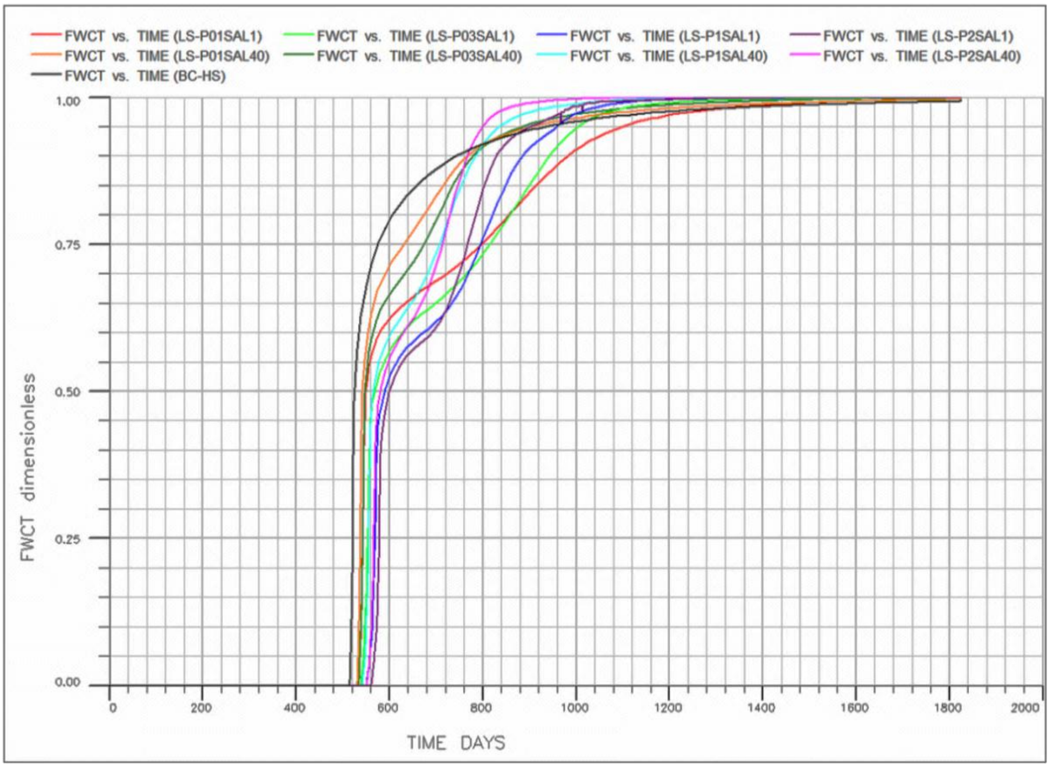


Figure 4. 27 The water-cut of LS flooding in the first water flooding phase and polymer flooding in the secondary phase

Field pressure of HS flooding and LS flooding, respectively, in the first water flooding phase and polymer solution in the secondary phase are presented in Fig.4.28 and Fig.4.29. From both of HS flooding and LS flooding, it is obviously seen that polymer solutions with high concentration and brine 1000 ppm have the field pressure build up significantly high that could cause a fracture problem in the reservoir. For the low concentration polymer solutions with high salinity, they also have some changing in field pressure but not much different from the base case.

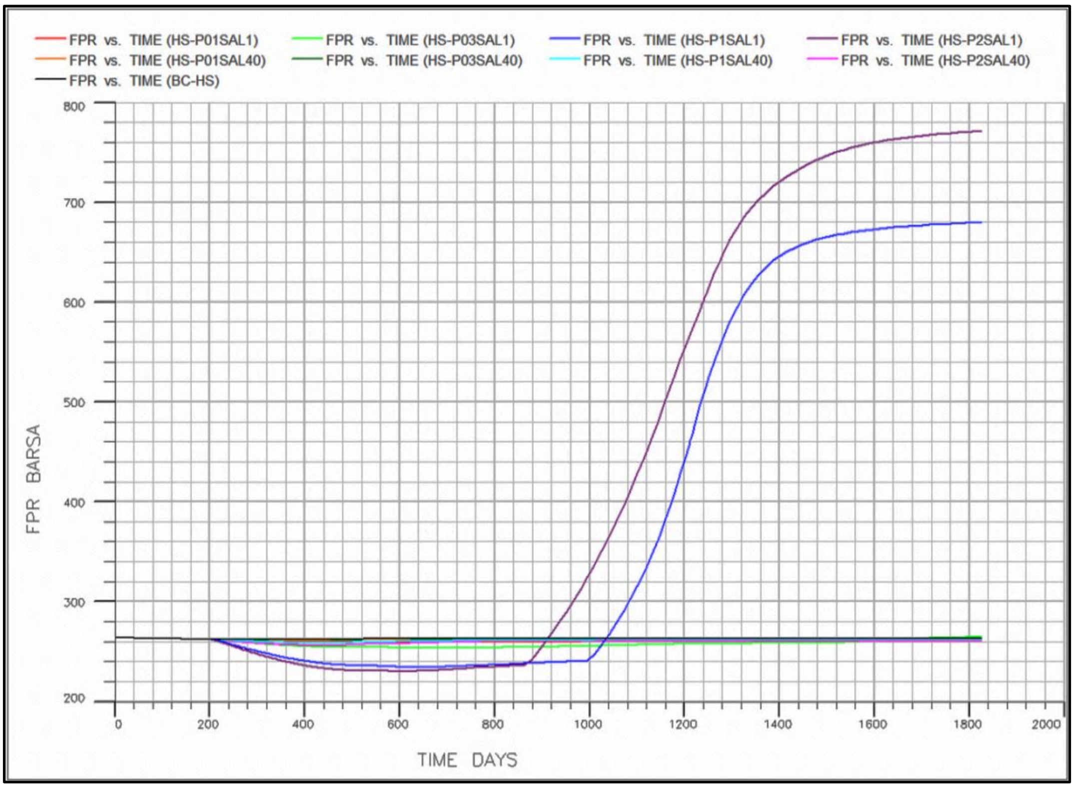


Figure 4. 28 The field pressure of HS flooding in the first water flooding phase and polymer solution in the secondary phase

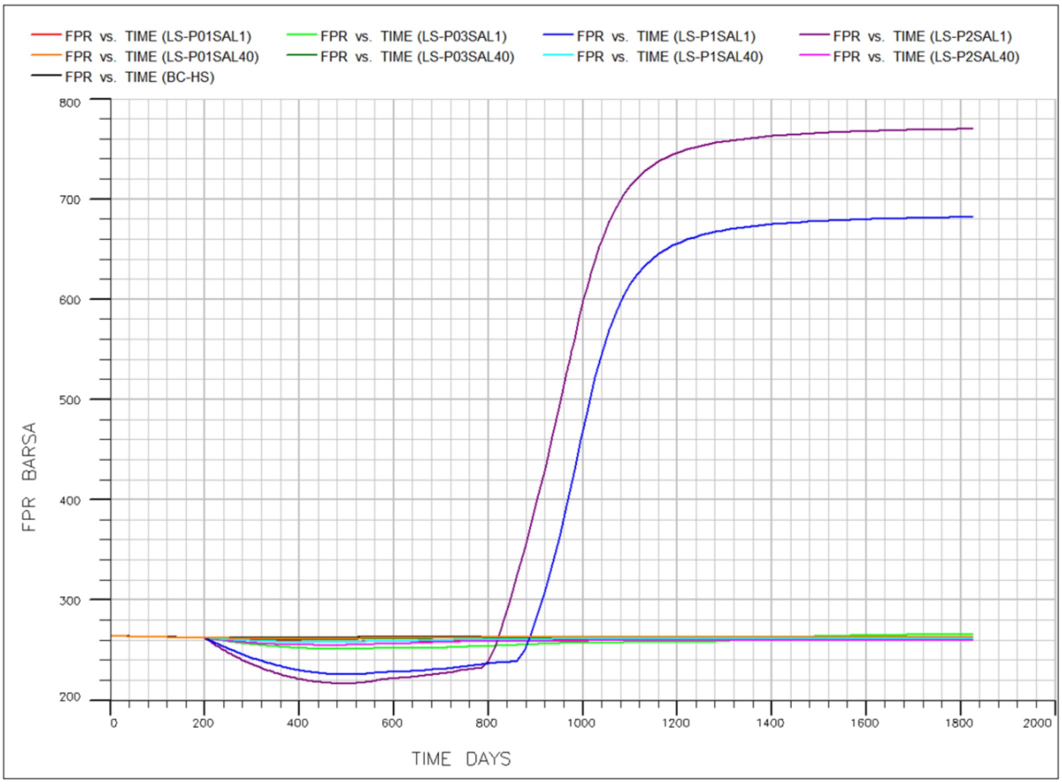


Figure 4. 29 The field pressure of LS flooding in the first water flooding phase and polymer solution in the secondary phase

4.2.4.1 Effect of polymer concentration

The comparison of varied polymer concentration with the same first water flooding phase and salinity in the polymer solution is illustrated in Fig.4.30. “HS/SAL1000” is represented for HS as first water flooding phase and salinity 1000 ppm in the polymer solution. It can be seen clearly that when using both HS and LS flooding in the first water flooding phase with salinity 1000 ppm in the polymer solution, polymer concentration does not affect much to higher oil recovery, particularly, oil recovery decreases at 0.2%wt polymer concentration. In another side, when using salinity 40000 ppm in polymer solution, oil recovery is higher according to increasing polymer concentration even not a big difference.

Lake (1989) concluded that polymer solution can improve higher oil recovery by increasing viscosity of water solution resulting less water mobility and reducing rock relative permeability to water due to absorption and entrapment of huge macromolecular polymer in the porous media. Sheng (2011) showed that the elastic modulus and relaxation time of the polymer solution increased with polymer concentration, thus viscosity of polymer solution increase. However, he also explained salinity effect that the salt concentration causes ionic strength increased, the ionic shield effect increases. Then polymer molecules cannot crimp freely, so the elastic modulus and relaxation time decreased, the solution viscosity decreased with NaCl concentration.

From the reasons discussing above that the higher polymer concentration and lower salinity result higher polymer solution viscosity, we propose that the polymer viscosity is too high in this test when combined with 1000 ppm salinity. So that, firstly, polymer solution moves difficultly and, secondly, after injecting polymer solution in the system for a while, polymer starts to block the rock permeability. Then, oil cannot be produced as much as we expect to see from polymer flooding and when oil production decrease, water is produced instead. Especially, when polymer concentration is 0.2%wt, these effects lead to lower oil recovery compared to the lower polymer concentration. Moreover, the continuous polymer injection that used to drive oil and polymer solution through the reservoir in difficult flowing condition causes high pressure as we can see in field pressure result. This high pressure is not possible to be allowed in the reality because it can pressurize and fracture the formation. Since we controlled the reservoir volume rate, this high pressure result can occur without no limitation; thus, the pressure control is considered importantly in polymer flooding.

However, the high salinity in polymer solution make the viscosity of the mixture similar to the formation water viscosity, resulting oil recovery is not much different from the water flooding base case. Consequently, we can see the small increasing of oil recovery due to the small higher polymer viscosity when increasing polymer concentration. It means that combination of polymer and high salinity in the solution can still cause viscosity increased from polymer effect but not as much as the combination with low salinity.

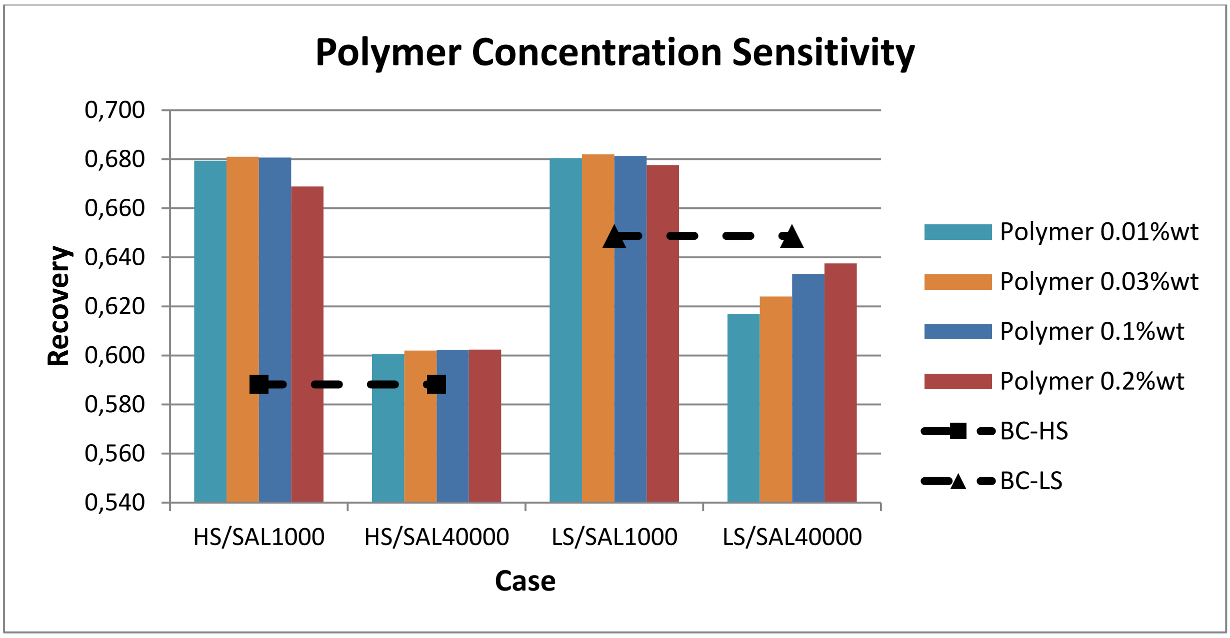


Figure 4. 30 The comparison of varied polymer concentration with the same first water flooding phase and salinity in the polymer solution (BC-HS and BC-LS are the base case for comparison)

4.2.4.2 Effect of salinity in polymer solution

The comparison of salinity in polymer solution when control the same first water flooding phase and the polymer concentration is displayed Fig.4.31. "HS/P0.01%wt" is represented for HS as first water flooding phase and 0.1 g/L or 0.01%wt polymer concentration. It can be demonstrated that increasing salinity in polymer solution gives obviously negative effect to oil recovery.

Also, from the discussion in the previous part, it clarifies that the combination of high salinity and polymer can give just only a small effect to solution viscosity, thus oil recovery is improved insignificantly whereas the combination with low salinity can impact essentially to polymer solution viscosity. However, the too high viscosity is possible to affect to lower oil recovery.

From the figure, we also can see another interesting point when comparing the effect from the combination of polymer with high salinity and the effect of low salinity flooding in the secondary phase (BC-LS), while both used LS flooding in the first water flooding phase. The LS flooding in the secondary phase should still influence to the more water-wet wettability changing continued from the first water flooding. This means that viscosity effect from polymer with high salinity solution ascend less than the wettability changing effect, even it is better than HS flooding. In the opposite site, the effect from the combination of polymer and low salinity give more powerful than wettability changing effect.

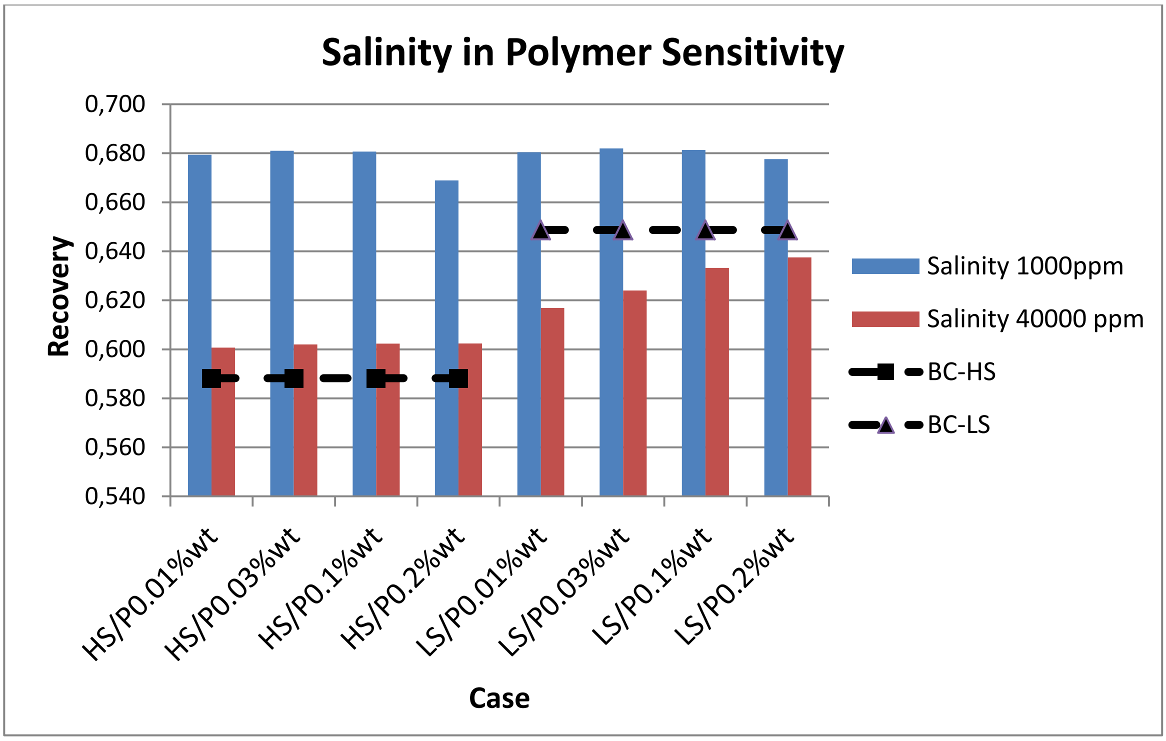


Figure 4. 31 The comparison of salinity in polymer solution when controlling the same first water flooding phase and the polymer concentration (BC-HS and BC-LS are the base cases for comparison)

4.2.4.3 Effect of salinity in primary recovery phase

Fig.4.32 presents the comparison between HS and LS flooding in the first water flooding phase when keep the same salinity and polymer concentration solution in the secondary phase. “P01%SAL1000” is represented for 0.1 g/L or 0.01%wt polymer concentration with 1000 ppm salt concentration. The figure shows that decreasing salinity from 40000 ppm to 1000 ppm in primary recovery phase influence to some small higher oil recovery when combining polymer solution with low salinity, whereas it affects a great higher recovery in combination with high salinity.

The previous part is discussed that the viscosity effect from polymer with high salinity solution can be almost neglected to oil recovery and give even less potential than the wettability changing effect. Therefore, the effect of wettability changing in the first water flooding phase play significantly role to the overall recovery in this case. Since LS flooding modifies wettability to more water-wet system, oil is produced more than HS flooding. In case of the combination of polymer and low salinity, although there is wettability changing in the first water flooding phase, the viscosity effect in the secondary phase impacts to overall oil production better than wettability effect. Accordingly, there is not big difference of oil recovery by changing salinity in the first water flooding phase compared to the polymer flooding effect.

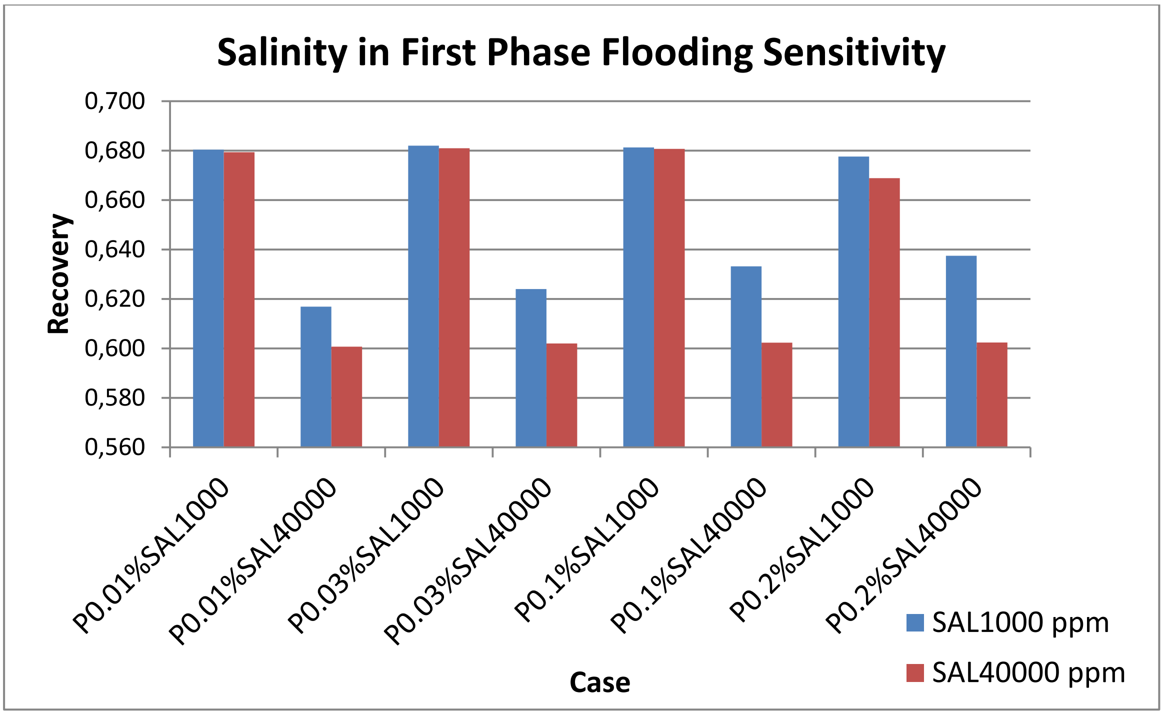


Figure 4. 32 The comparison between HS and LS flooding in the first water flooding recovery phase with the same salinity and polymer concentration solution in the secondary phase

4.2.4.4 Summary

From combination of LS and polymer flooding, based on polymer properties used in this study, increasing polymer concentration can improve oil recovery because of increasing viscosity in water flooding. The lower salinity in the first water flooding phase still can change the system become more water-wet, while lower salinity in the polymer solution can cause even higher viscosity polymer solution. The high salinity in polymer solution makes the polymer flooding results almost the same to formation water flooding due to similar viscosity. However, the low salinity in polymer solution can cause too high viscosity that move difficultly and block the permeability in the reservoir, particularly with also high polymer concentration. Therefore, the optimization is needed to find the best condition of salinity and polymer concentration used in polymer flooding.

Since the viscosity of the combination of low salinity and polymer is very high and leads to high field pressure that could cause fracture and destroy the formation of reservoir, it is better to inject polymer solution for a period of time and continued by water flooding. Therefore, water flooding as tertiary injection phase after polymer injection will be studied in the next part. HS-P01SAL1 case which are HS flooding in first water flooding phase and followed by 0.01%wt polymer concentration with 1000ppm salinity solution, are selected by reason of using low polymer concentration while giving quite similar oil recovery to the higher concentration and does not cause field pressure problem.

4.2.5 Combination of Low Salinity Water Flooding and Alkaline – Surfactant – Polymer (ASP) Flooding

After studying the individual effect in combination of low salinity and each chemical flooding type, the combination of low salinity and mix chemical flooding types is discussed in this section. It is divided to three parts: Alkaline (A) – Polymer (P), Alkaline (A) – Surfactant (S) and Surfactant (S) – Polymer (P). From the previous discussion, all chemical types have the same results in the study of salinity in the primary phase flooding that is the effect of low salinity is wettability changing and cannot make big difference to overall oil recovery compared to high salinity flooding. So, all cases, in this part, were started by HS flooding from the beginning to 200 days of production and followed by the continuous mix chemical solution flooding until the end of production. The salinity in the chemical solution was varied by 1000 ppm represented low salinity (LS) and 40000 ppm stood for high salinity (HS).

Each couple of chemical solution flooding, there are three interesting topics: effect of the first chemical type to the combination, effect of another chemical type to combination and effect of salinity in the chemical solution.

4.2.5.1 Combination of Low Salinity Water Flooding and Alkaline - Polymer (AP) Flooding

Alkaline (A) and polymer (P) were varied to high and low concentration: 1.5%wt and 3%wt, respectively, for alkaline solution and 0.01%wt and 1%wt, respectively, for polymer solution. Each concentration is matched and mixed by low and high salinity water. Table 4.6 summarizes the short detail and recovery result of cases from the combination of LS flooding and AP flooding.

Table 4. 6 The short detail and recovery result of cases from the combination of LS flooding and AP flooding

Name	Details	Recovery (%)
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
HS-LS	HS (0-200 days) + LS continuing (201-1826 days)	64.3
HS-A15S0P01SAL1	HS(200) + **Alkaline 1.5%wt - Polymer 0.01%wt slug - Salinity 1000 ppm** (201-1826 days)	67.9
HS-A15S0P01SAL40	HS(200) + **Alkaline 1.5%wt - Polymer 0.01%wt slug - Salinity 40000 ppm** (201-1826 days)	60.0
HS-A15S0P1SAL1	HS(200) + **Alkaline 1.5%wt - Polymer 0.1%wt slug - Salinity 1000 ppm** (201-1826 days)	67.5
HS-A15S0P1SAL40	HS(200) + **Alkaline 1.5%wt - Polymer 0.1%wt slug - Salinity 40000 ppm** (201-1826 days)	60.3
HS-A30S0P01SAL1	HS(200) + **Alkaline 3%wt - Polymer 0.01%wt slug - Salinity 1000 ppm** (201-1826 days)	81.2
HS-A30S0P01SAL40	HS(200) + **Alkaline 3%wt - Polymer 0.01%wt slug - Salinity 40000 ppm** (201-1826 days)	71.0
HS-A30S0P1SAL1	HS(200) + **Alkaline 3%wt - Polymer 0.1%wt slug - Salinity 1000 ppm** (201-1826 days)	90.1
HS-A30S0P1SAL40	HS(200) + **Alkaline 3%wt - Polymer 0.1%wt slug - Salinity 40000 ppm** (201-1826 days)	71.0
HS-A15SAL1	HS (200 days) + **Alkaline 1.5%wt with salinity 1000 ppm** (201-1826 days)	64.3
HS-A15SAL40	HS (200 days) + **Alkaline 1.5%wt with salinity 40000 ppm** (201-1826 days)	59.8
HS-A30SAL1	HS (200 days) + **Alkaline 3%wt with salinity 1000 ppm** (201-1826 days)	68.7
HS-A30SAL40	HS (200 days) + **Alkaline 3%wt with salinity 40000 ppm** (201-1826 days)	67.6
HS-P01SAL1	HS (200 days) + **Polymer 0.01%wt (100ppm) with salinity 1000 ppm** (201-1826 days)	67.9
HS-P01SAL40	HS (200 days) + **Polymer 0.01%wt (100ppm) with salinity 40000 ppm** (201-1826 days)	60.1
HS-P1SAL1	HS (200 days) + **Polymer 0.1%wt (1000ppm) with salinity 1000 ppm** (201-1826 days)	68.1
HS-P1SAL40	HS (200 days) + **Polymer 0.1%wt (1000ppm) with salinity 40000 ppm** (201-1826 days)	60.2

Fig.4.33, Fig.4.34, Fig.4.35and Fig.4.36 show the oil recovery, oil production rate, water-cut and field pressure profile. It is obviously seen that the case with high alkaline and high polymer concentration with low salinity give the highest oil recovery and much different from the other cases. Its production rate is also kept higher than the others since after water breakthrough until almost the end of production life. Water-cut is consistent with oil production rate profile. It can be noticed that the cases with high polymer concentration and low salinity cause high field pressure problem. The one with low alkaline concentration cause a very high pressure that could collapse the formation while another one with high alkaline concentration does not reach high pressure, however pressure decrease much more than the other cases. This can be the reason of high alkaline concentration can help polymer solution drive easier, thus field pressure does not increase as high as the case with low alkaline concentration.

Fig.4.37 presents the comparison of oil recovery between using the alkaline flooding, the polymer flooding and AP flooding as the second recovery phase varied chemical concentration and salinity in the solution.

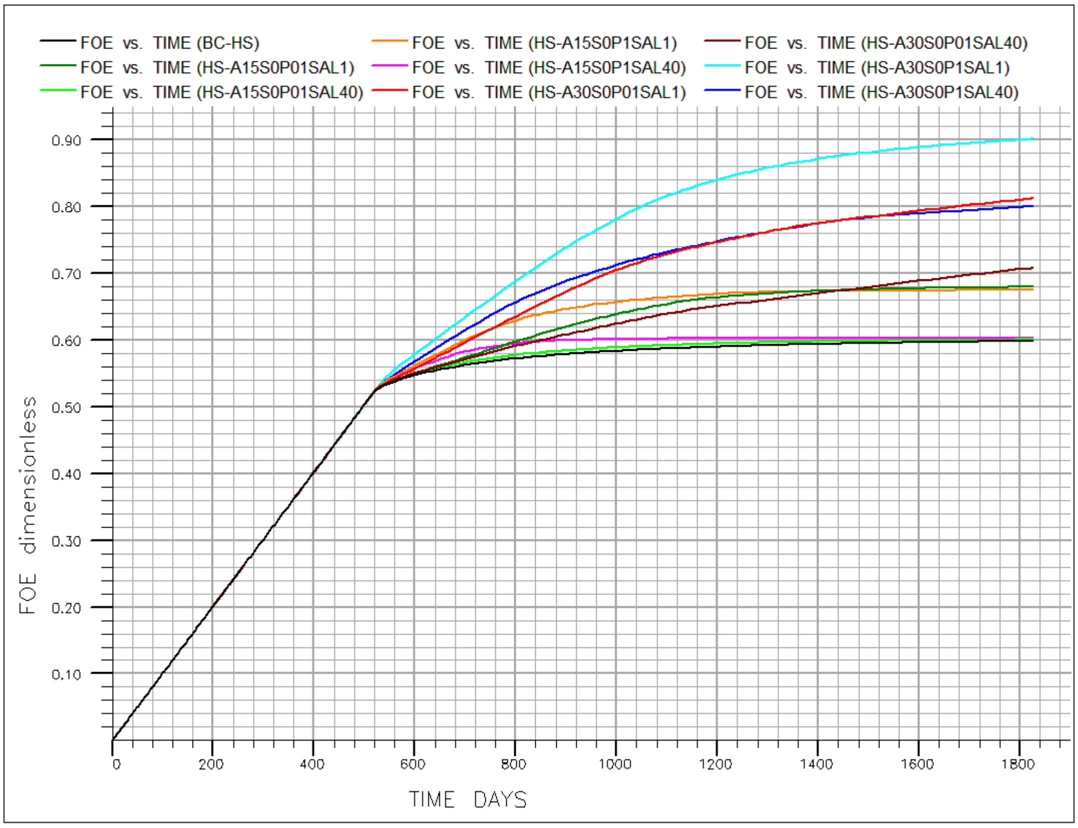


Figure 4. 33 The oil recovery of the combination of low salinity and AP flooding

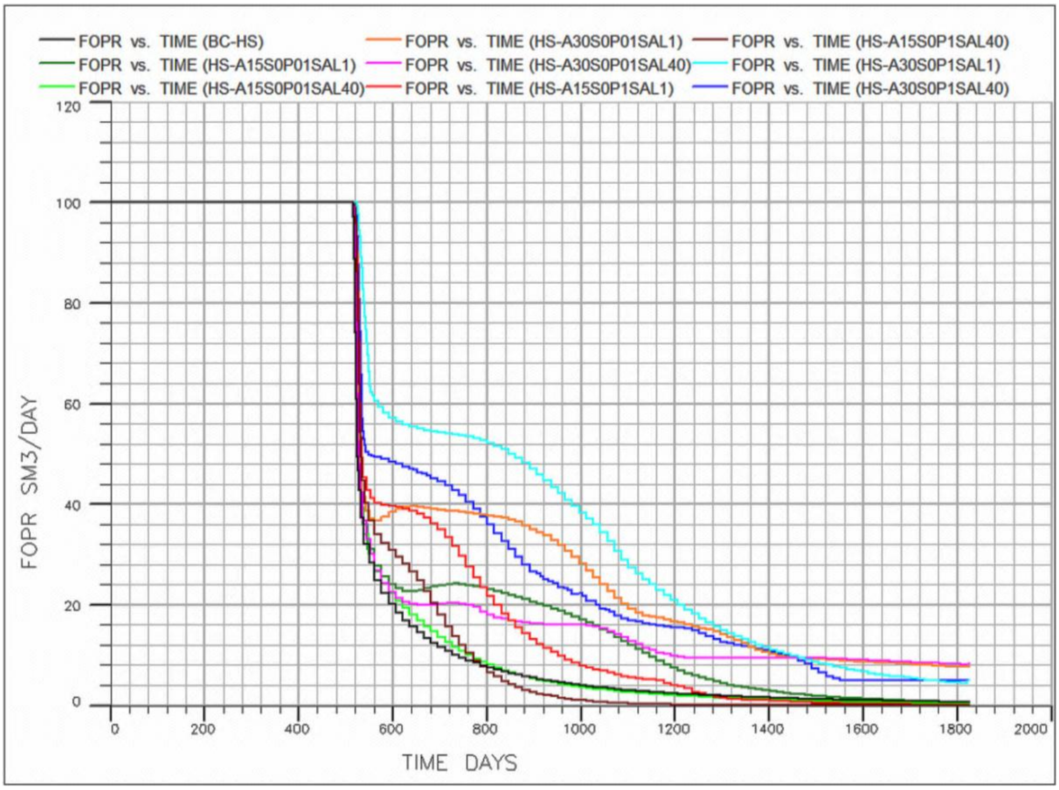


Figure 4. 34 The oil production rates of the combination of low salinity and AP flooding

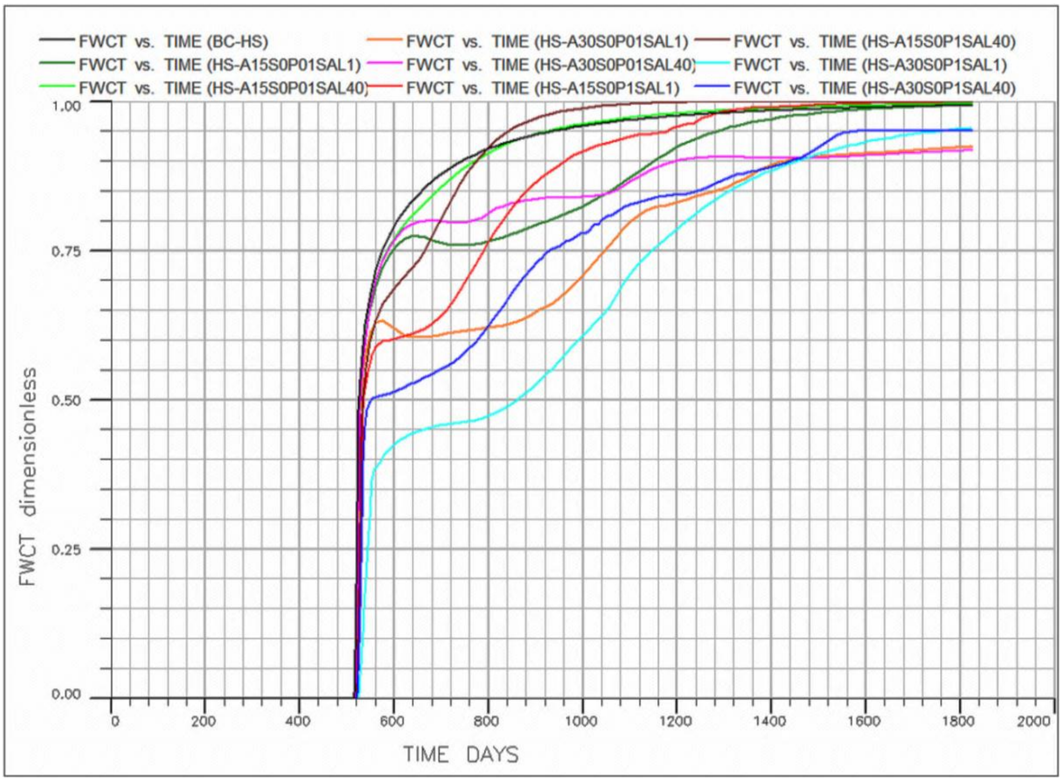


Figure 4. 35 The water-cut results of the combination of low salinity and AP flooding

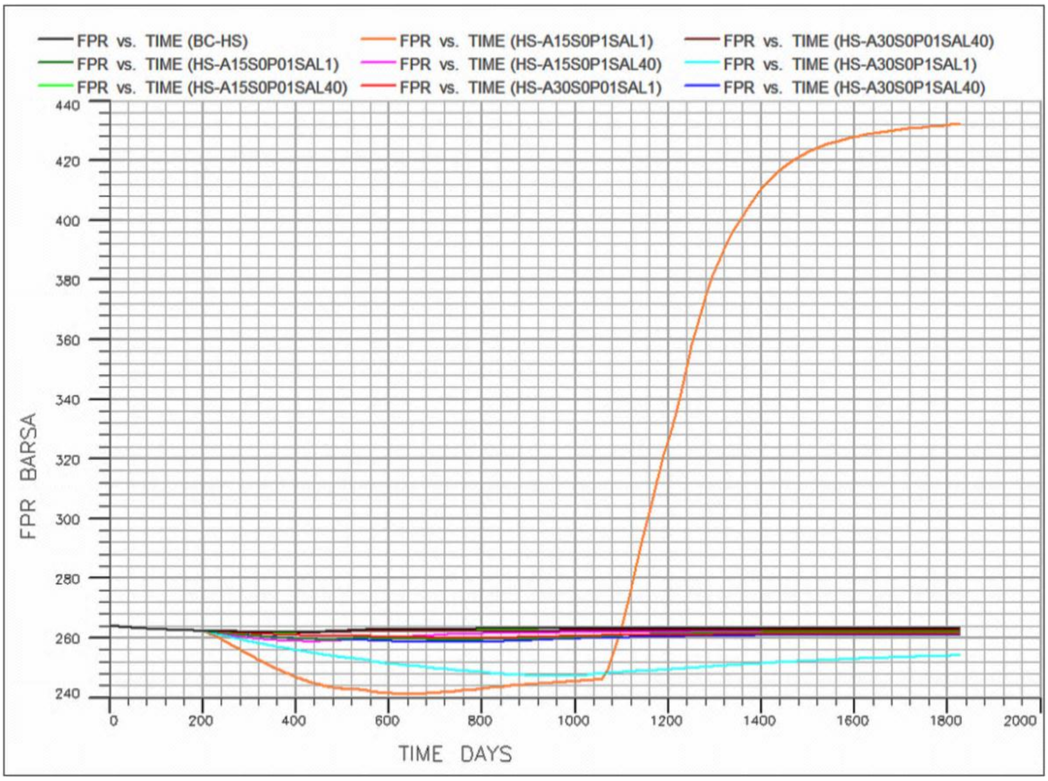


Figure 4. 36 The field pressure profiles of the combination of low salinity and AP flooding

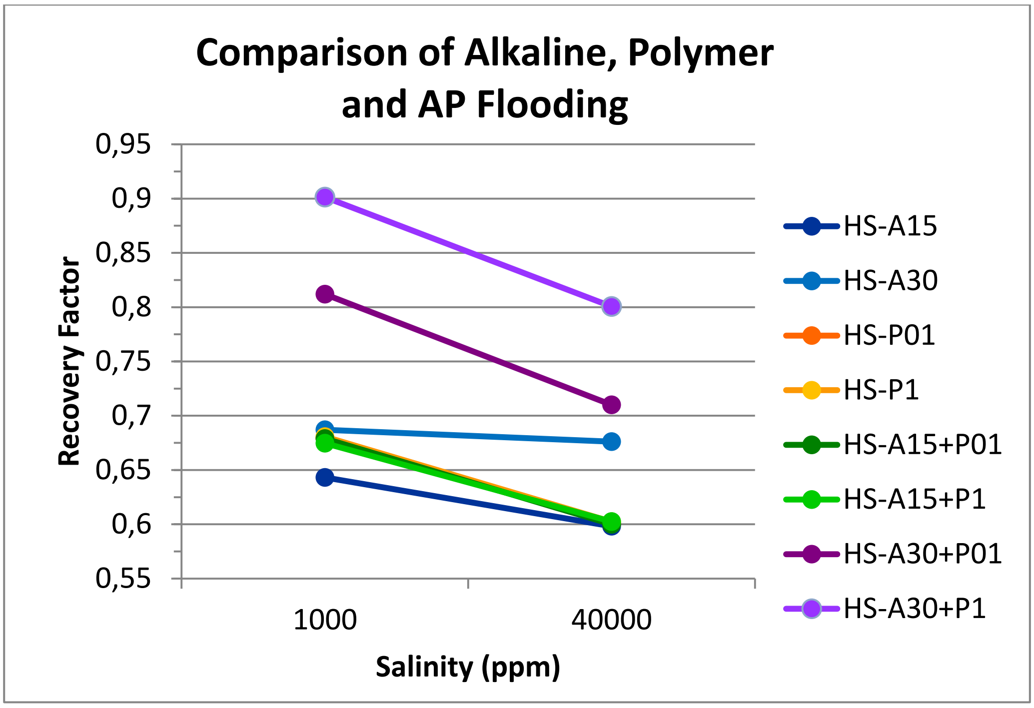


Figure 4. 37 The comparison of oil recovery between using the alkaline flooding, the polymer flooding and AP flooding varying chemical concentration and salinity (HS-A15/A30 = alkaline flooding, HS-P01/P1 = polymer flooding and HS-A15+P01 = AP flooding)

4.2.5.1.1 Effect of alkaline concentration to AP flooding

The effects of alkaline have been studies by varying the concentrations of alkaline in the AP solution, comparing the AP flooding with the polymer flooding. It can be seen that for both HS and LS in solution, the cases with high alkaline concentration have higher oil recovery than low alkaline concentration, no matter how polymer concentration is. However, with low alkaline concentration, it does not help the AP flooding result higher oil recovery comparing to pure polymer flooding. The study of the alkaline flooding in section 4.2.2 corresponds to this result. It proposes that alkaline concentration 1.5%wt is not enough to affect higher oil recovery, whereas alkaline concentration 3%wt can influence stronger due to IFT reduction effect.

Green (1998) supported that ,in general, an increase in concentration of alkaline increases the additional recovery as it is well known that the injected alkaline quickly reacts with the carboxylic acid groups of crude oil forming in situ surfactant; hence presence of alkaline in a solution significantly decrease IFT between oil and water. Moreover, Sheng (2011) confirmed that polymer solution in the presence of alkaline may also be due to charge-shielding mechanism and hydrolysis polymer. Alkaline can modify the viscosity of a HPAM solution in two ways; first, alkaline provides cations into the polymer solution. These cations can reduce polymer viscosity through the charge shielding mechanism. Second, alkaline can hydrolyze the amide groups on the polymer chain (base hydrolysis). This process can increase the polymer solution viscosity. Obviously, the net effect of alkali on the polymer solution viscosity depends on the relative extent of these two factors. In addition, alkaline can reduce the adsorption of polymer on the rock surface, so enhancing the effectiveness of the polymer drive.

From checking the chemical solution viscosity and polymer concentration adsorbed by rock, the results can confirm the supporting reasons that alkaline impact to only small higher chemical solution viscosity but significantly decrease the adsorbed polymer on the rock surface. Moreover, the IFT reduction caused by alkaline also drive the AP solution move easier through the system, results to no high field pressure problem. Therefore, adding alkaline to the combined AP flooding method can cause higher oil production due to the reason above and, particularly, when the alkaline concentration is high enough.

4.2.5.1.2 Effect of polymer concentration to AP flooding

By varying polymer concentration in AP solution and comparing with pure alkaline solution, the effects of polymer to AP flooding have been studied. From Fig.4.37, it can be illustrated that with low salinity, adding polymer in AP solution can cause higher oil recovery than pure alkaline flooding and even higher when combined with high alkaline concentration. With high salinity, both low and high polymer concentrations in the AP flooding affect hardly in low alkaline concentration flooding, while affect some in high alkaline concentration. But it seems like the effect in high salinity condition come from alkaline flooding instead of polymer flooding. From the study of polymer flooding in section 4.2.4, it sums that increasing polymer concentration results to increasing viscosity of polymer solution and oil recovery as well in low salinity condition, while high salinity causes neglecting effect in increasing viscosity of polymer solution, thus polymer flooding results almost as same as formation water flooding.

Samanta et al (2012) summarized her experiments that additional recovery increases only marginally depends on concentration of HPAM and salinity in solution. Injection of polymer increases the sweep efficiency, and hence, oil recovery. After a certain salinity condition and concentration of polymer, the sweep efficiency approaches to its limiting value and thus only marginal additional recovery is observed.

Consequently, the major effect of polymer to AP flooding is to improve sweep efficiency of AP flooding due to increase solution viscosity. The brine salinity in chemical solution is the important factor as high salinity can limit the effect of polymer. The higher polymer concentration and lower salinity result the higher solution viscosity and oil recovery. However, too high solution viscosity can cause difficulty in displacement process and too high field pressure situation.

4.2.5.1.3 Effect of salinity in chemical solution to AP flooding

From Fig.4.37, comparing the same type and concentration of chemical solution, low salinity results better oil recovery in all aspects. As discussing above that, in alkaline flooding, the low salinity condition in the solution can help changing favorable water-wet reservoir at the same time when alkaline reduce IFT and ,in polymer flooding, low salinity can increase viscosity of polymer solution that results improvement of sweep efficiency.

Shunhua et al. (2010) studied the effect of gradient salinity in ASP flooding. They summarized that if the injected salinity is somewhere in the system of the alkaline injection, then the profile of injection must pass through the optimal condition where the IFT is a minimum. If the injected salinity is below the optimal point, then the profile of low IFT is narrow and the IFT may increase before all of the mobilized oil is displaced. In the opposite site, if the injected salinity is near or above the optimal point, the surfactant and soap partition preferentially into the oil phase and are retarded, also resulting less effect of IFT reduction.

In AP flooding, based on our properties of alkaline and polymer in this study, it can be noticed that alkaline play more important role than polymer. Salinity is also major factor that can impact to both alkaline and polymer, especially to the viscosity of polymer solution. The higher concentration of alkaline and polymer with low salinity are preferable to high oil recovery. However, due to the awareness of side effect such as high field pressure, the optimization of all factors is important.

4.2.5.2 Combination of Low Salinity Water Flooding and Alkaline - Surfactant (AS) Flooding

Alkaline (A) and surfactant (S) were varied to high and low concentration: 1.5%wt and 3%wt, respectively, for alkaline solution and 1%wtt and 2%wt, respectively, for surfactant solution. Low salinity and high salinity are applied in each coupled of chemical solution. Table 4.7 summarizes the short detail and recovery result of cases from the combination of LS flooding and AS flooding.

Table 4. 7 The short details and recovery results of cases from the combination of LS flooding and AS flooding

Name	Details	Recovery (%)
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
HS-LS	HS (0-200 days) + LS continuing (201-1826 days)	64.3
HS-A15S10P0SAL1	HS(200) + **Alkaline 1.5%wt - Surfactant 1%wt slug - Salinity 1000 ppm** (201-1826 days)	71.3
HS-A15S10P0SAL40	HS(200) + **Alkaline 1.5%wt - Surfactant 1%wt slug - Salinity 40000 ppm** (201-1826 days)	70.2
HS-A15S20P0SAL1	HS(200) + **Alkaline 1.5%wt - Surfactant 2%wt slug - Salinity 1000 ppm** (201-1826 days)	72.0
HS-A15S20P0SAL40	HS(200) + **Alkaline 1.5%wt - Surfactant 2%wt slug - Salinity 40000 ppm** (201-1826 days)	70.5
HS-A30S10P0SAL1	HS(200) + **Alkaline 3%wt - Surfactant 1%wt slug - Salinity 1000 ppm** (201-1826 days)	73.7
HS-A30S10P0SAL40	HS(200) + **Alkaline 3%wt - Surfactant 1%wt slug - Salinity 40000 ppm** (201-1826 days)	72.5
HS-A30S20P0SAL1	HS(200) + **Alkaline 3%wt - Surfactant 2%wt slug - Salinity 1000 ppm** (201-1826 days)	74.9
HS-A30S20P0SAL40	HS(200) + **Alkaline 3%wt - Surfactant 2%wt slug - Salinity 40000 ppm** (201-1826 days)	73.6
HS-A15SAL1	HS (200 days) + **Alkaline 1.5%wt with salinity 1000 ppm** (201-1826 days)	64.3
HS-A15SAL40	HS (200 days) + **Alkaline 1.5%wt with salinity 40000 ppm** (201-1826 days)	59.8
HS-A30SAL1	HS (200 days) + **Alkaline 3%wt with salinity 1000 ppm** (201-1826 days)	68.7
HS-A30SAL40	HS (200 days) + **Alkaline 3%wt with salinity 40000 ppm** (201-1826 days)	67.6
HS-S10SAL1	HS (200 days) + **Surfactant 1%wt with salinity 1000 ppm** (201-1826 days)	70.0
HS-S10SAL40	HS (200 days) + **Surfactant 1%wt with salinity 40000 ppm** (201-1826 days)	68.2
HS-S20SAL1	HS (200 days) + **Surfactant 2%wt with salinity 1000 ppm** (201-1826 days)	71.1
HS-S20SAL40	HS (200 days) + **Surfactant 2%wt with salinity 40000 ppm** (201-1826 days)	68.4

The result of oil recovery, oil production rate, water-cut and field pressure profile are presented in Fig.4.38, Fig.4.39, Fig.4.40 and Fig.4.41 Results obviously appear that all cases have oil recovery close to each other, Moreover, oil production rate, water-cut and field pressure have the same trend between all cases. From oil production rate graph, the trend shows in a couple of chemical solution type that varied low salinity and high salinity. The best case in AS flooding is still the case with high alkaline and high surfactant concentration with low salinity.

Fig.4.42 compares the oil recovery between using the alkaline flooding, the surfactant flooding and AS flooding as the second recovery phase varied chemical concentration and salinity in the solution.

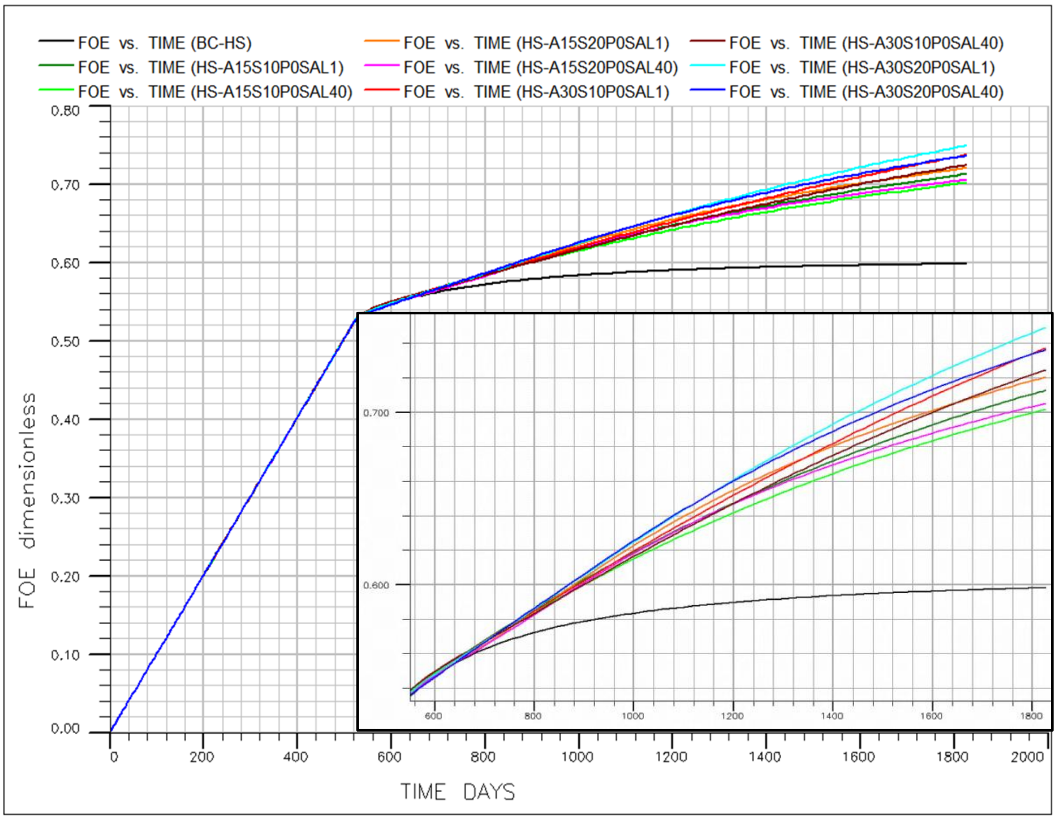


Figure 4. 38 The oil recovery of the combination of low salinity and AS flooding

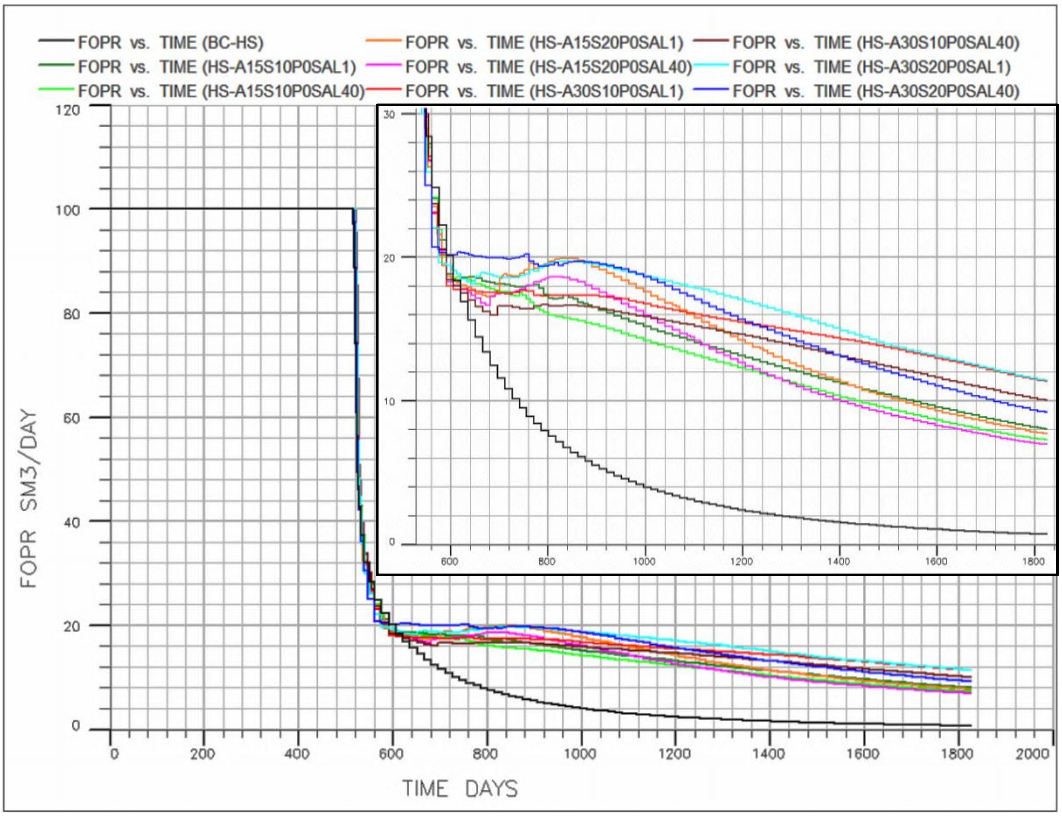


Figure 4. 39 The oil production rates of the combination of low salinity and AS flooding

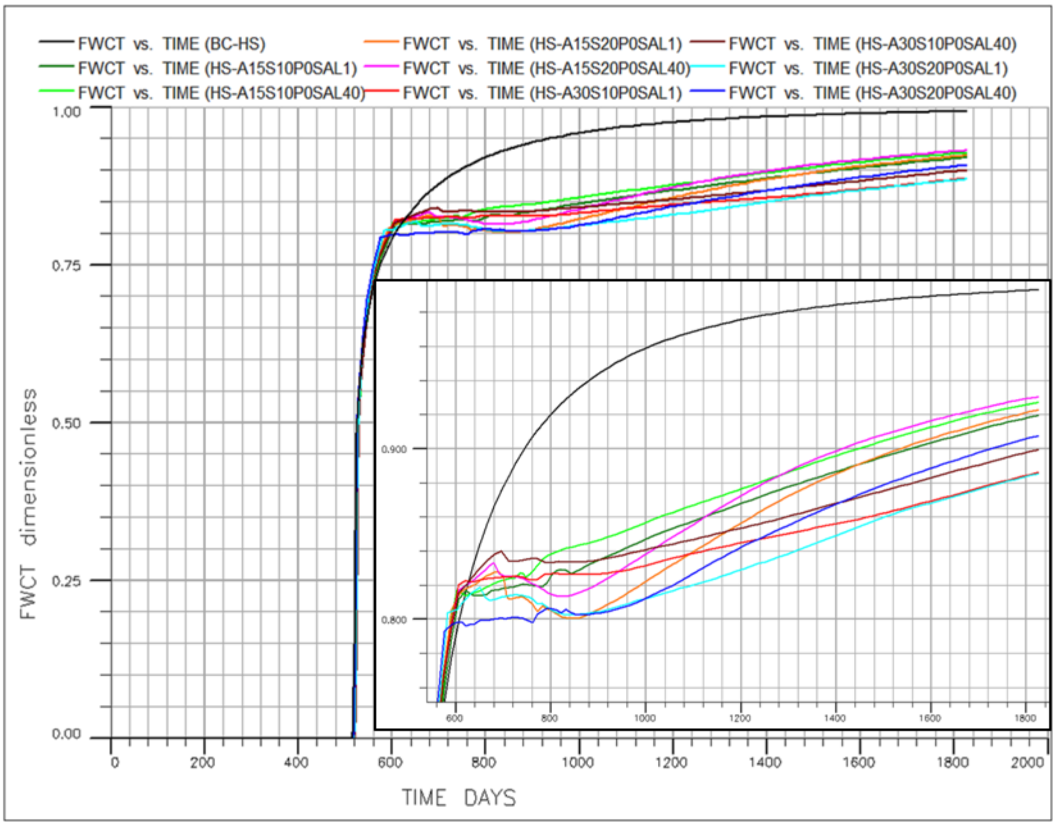


Figure 4. 40 The water-cut results of the combination of low salinity and AS flooding

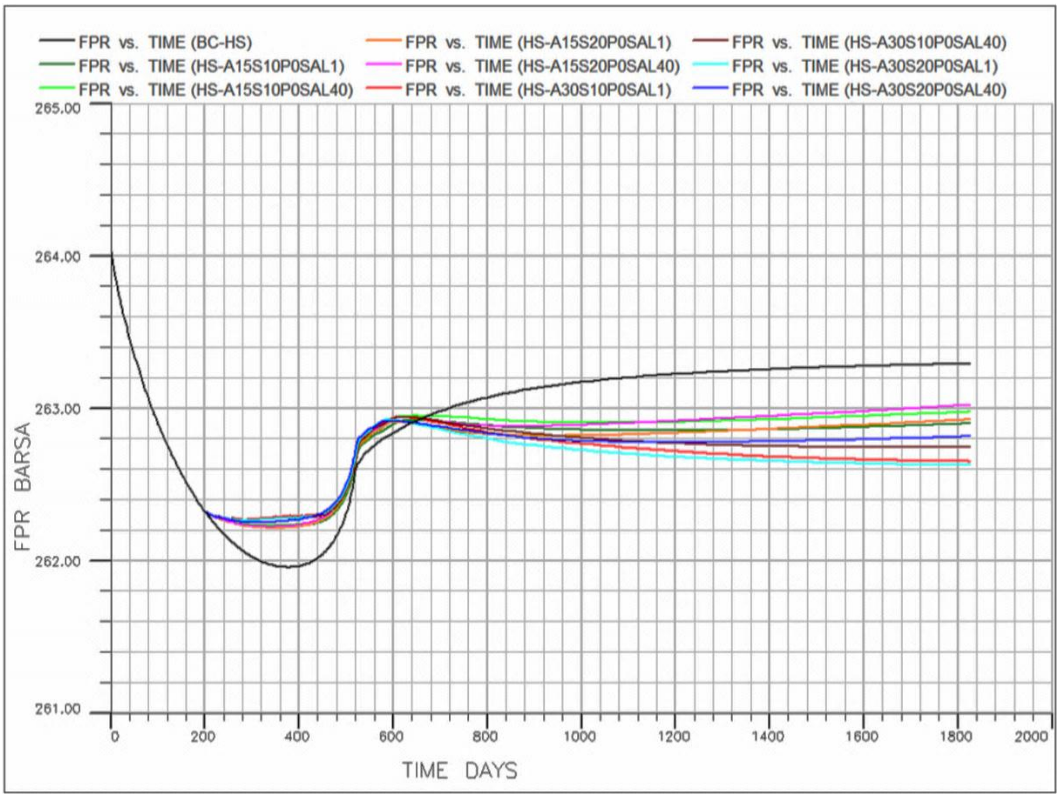


Figure 4. 41 The field pressure profiles of the combination of low salinity and AS flooding

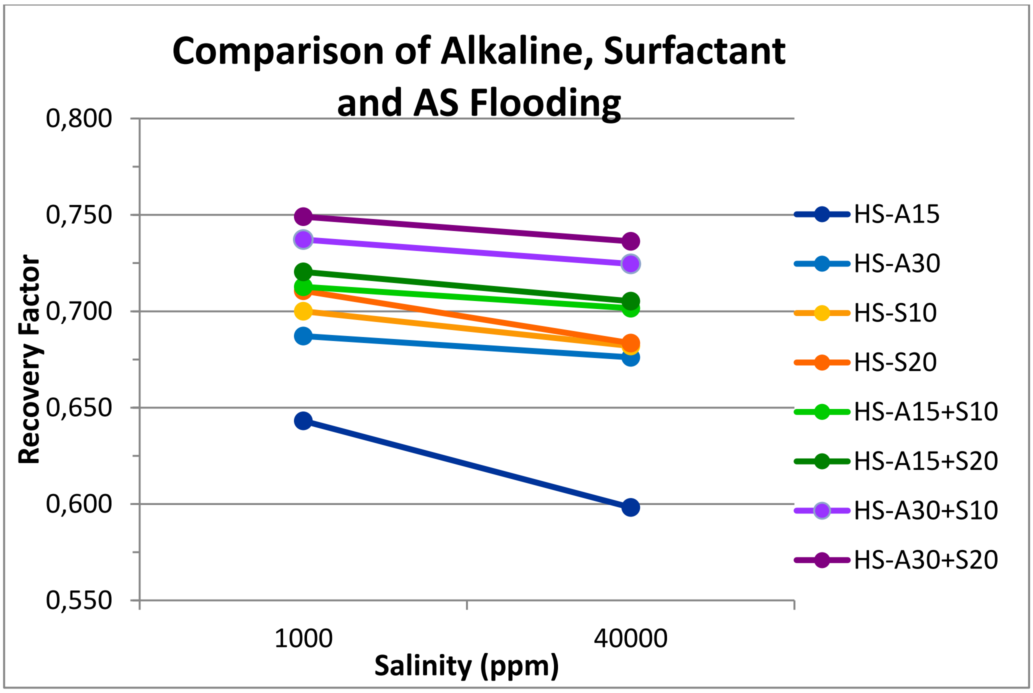


Figure 4. 42 The comparison of oil recovery between using the alkaline flooding, the surfactant flooding and AS flooding varying chemical concentration and salinity (HS-A15/A30 = alkaline flooding, HS-S10/S20 = surfactant flooding and HS-A15+S10 = AS flooding)

4.2.5.2.1 Effect of alkaline concentration to AS flooding

Comparing the AS flooding with the pure surfactant flooding, the effects of alkaline have been studies by varying the concentrations of alkaline in the AS solution. From Fig.4.42, the low alkaline concentration affects to some increasing of oil recovery based on pure surfactant flooding and the high alkaline concentration affect even more. Although the study of the alkaline flooding in section 4.2.2 shows that alkaline concentration 1.5%wt is not strong enough to impact higher oil recovery, it gives some effect when combining with surfactant flooding.

Sheng (2011) supported that alkaline forms soap by reacting with naturally occurring organic acid in the crude oil, which interact synergistically with added surfactant to produce ultra-low IFT. The ultra-low IFT is obtained by surfactant distribution between oil and water phase, and surfactant arrangement at interface of oil/water. Moreover, Samanta et al. (2012) said the main problem of surfactant is that its concentration is depleted quickly by adsorption onto the rock surface. Use of alkali reduces the surfactant depletion rate. Krumrine et al. (1983) claimed that the alkaline injected with surfactant can reduce surfactant adsorption on the rock surface, play the role of ionic strength and lower IFT.

In our test, it confirms that alkaline decreases the amount of adsorbed surfactant on the rock surface. Therefore, although alkaline concentration 1.5%wt is quite low in the other cases, it still gives some effect in lowering adsorption of surfactant. The higher alkaline concentration impacts absolutely to even lower IFT and surfactant adsorption.

4.2.5.2.2 Effect of surfactant concentration to AS flooding

In studying of surfactant effect to AS flooding, the varying surfactant concentration in AS solution is compared to the pure alkaline solution. From Fig.4.42, it can be demonstrated that increasing surfactant concentration in AS flooding can enhance more oil recovery. Although AS flooding is much better than only alkaline flooding, when keeping constant alkaline concentration in AS solution, higher surfactant concentration can cause only small amount of incremental oil recovery. This result can be supported by the conclusion in section 4.2.3 that surfactant concentration 2%wt concentration is over CMC and that causes the recovery of the cases with surfactant concentration 2%wt are not largely different from 1%wt.

Thigpen et al. (1991) added surfactant to the alkaline solution to reduce the oil/water IFT. The surfactant was soluble in both the aqueous solution and the reservoir oil but more soluble in the former. The addition of surfactant made alkaline flooding more efficient in recovering the water flood residual oil. Rudin et al. (1994) investigated the effect of added surfactant on interfacial tension and spontaneous emulsification in alkaline and acidic oil systems. They found that adding surfactant reduced the equilibrium IFT to an ultralow value. The pH range for ultralow IFT and for spontaneous emulsification was also widened. The addition of surfactant also caused a higher interfacial resistance to mass transfer, which reduced the rate of acid ionization, resulting in a longer period of low dynamic IFT. Zhang et al. (2006) showed results of his experiment as a good synergy effect between alkali and surfactant. oil is easily emulsified into the water phase to form oil in water emulsions, and then entrains along with the flowing aqueous phase. These pictures manifest that water drops inside the oil phase are formed in the core during alkaline-only flooding, while oil in water emulsions is formed during alkaline/surfactant flooding, thus the alkaline/surfactant system is better than alkaline-only flooding. However, Samanta et al. (2012) suggested that increasing surfactant can cause significantly additional oil recovery but the concentrations of surfactants are generally kept above their CMC.

Therefore, there is a possibility that surfactant can reduce IFT to become ultralow IFT that create even better efficiency for the water flooding. Moreover, surfactant in AS solution can extend the period of low dynamic IFT due to increase interfacial resistance to mass transfer. However, the concentration of surfactant is need to be considered because the high surfactant concentration that is above CMC value is ineffective and not economical.

4.2.5.2.3 Effect of salinity in chemical solution to AS flooding

At the same type and concentration of chemical solution, low salinity in AS solution results better oil recovery than high salinity in all aspects. From Fig.4.42, it can be noticed that salinity can influence to surfactant more than alkaline flooding. In high salinity condition, high alkaline concentration still produces high oil recovery comparing to low alkaline concentration, while high and low surfactant concentration affect almost the same recovery.

Apart from surfactant flooding, alkaline also create in-situ surfactant in the reservoir. Shunhua et al. (2010) found in their core flooding experiments that prior to surfactant breakthrough, oil bank recovery occurred with Type II brine, which was a mixture of initial brine. Then, surfactant breakthrough and oil recovery corresponded with Type III salinity conditions, where results lowest IFT and surfactant trapped in the residual oil phase can begin mobilizing. Additional surfactant can mobilize from trapped oil. This means that at optimum surfactant concentration and optimum salinity, the lowest IFT is reached and oil is mobilized easier, resulting higher oil recovery. It confirms the previous study of salinity effect to alkaline flooding and surfactant flooding.

In AS flooding, based on our properties of alkaline and surfactant in this study, it is remarked that alkaline concentration influence to oil recovery more than surfactant. The major effect of combination of alkaline and surfactant is reaching the ultralow IFT condition that depends on alkaline and surfactant concentration and salinity in the solution as well. According to ultralow IFT, the addition of alkaline in AS flooding reduces the amount of surfactant required to reach this performance. Therefore the optimum alkaline and optimum surfactant concentration, which is high alkaline concentration and low surfactant concentration in this test, with optimum salinity is preferable.

4.2.5.3 Combination of Low Salinity Water Flooding and Surfactant - Polymer (SP) Flooding

The varying of high and low concentration: 1%wt and 2%wt, respectively, for surfactant solution and 0.01%wt and 1%wt, respectively, for polymer solution were tested in SP flooding. Each coupled of chemical solution is also applied by low salinity and high salinity. The short details and recovery results of cases from the combination of LS flooding and SP flooding are shown in Table 4.8.

Table 4. 8 The short details and recovery results of cases from the combination of LS flooding and SP flooding

Name	Details	Recovery (%)
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
HS-LS	HS (0-200 days) + LS continuing (201-1826 days)	64.3
HS-A0S10P01SAL1	HS(200) + Surfactant 1%wt - Polymer 0.01%wt slug - Salinity 1000 ppm (201-1826 days)	81.8
HS-A0S10P01SAL40	HS(200) + Surfactant 1%wt - Polymer 0.01%wt slug - Salinity 40000 ppm (201-1826 days)	71.0
HS-A0S10P1SAL1	HS(200) + Surfactant 1%wt - Polymer 0.1%wt slug - Salinity 1000 ppm (201-1826 days)	92.5
HS-A0S10P1SAL40	HS(200) + Surfactant 1%wt - Polymer 0.1%wt slug - Salinity 40000 ppm (201-1826 days)	81.0
HS-A0S20P01SAL1	HS(200) + Surfactant 2%wt - Polymer 0.01%wt slug - Salinity 1000 ppm (201-1826 days)	81.5
HS-A0S20P01SAL40	HS(200) + Surfactant 2%wt - Polymer 0.01%wt slug - Salinity 40000 ppm (201-1826 days)	71.2
HS-A0S20P1SAL1	HS(200) + Surfactant 2%wt - Polymer 0.1%wt slug - Salinity 1000 ppm (201-1826 days)	91.2
HS-A0S20P1SAL40	HS(200) + Surfactant 2%wt - Polymer 0.1%wt slug - Salinity 40000 ppm (201-1826 days)	80.1
HS-S10SAL1	HS (200 days) + Alkaline 1.5%wt with salinity 1000 ppm (201-1826 days)	70.0
HS-S10SAL40	HS (200 days) + Surfactant 1%wt with salinity 1000 ppm (201-1826 days)	68.2
HS-S20SAL1	HS (200 days) + Surfactant 1%wt with salinity 40000 ppm (201-1826 days)	71.1
HS-S20SAL40	HS (200 days) + Surfactant 2%wt with salinity 1000 ppm (201-1826 days)	68.4
HS-P01SAL1	HS (200 days) + Surfactant 2%wt with salinity 40000 ppm (201-1826 days)	67.9
HS-P01SAL40	HS (200 days) + Polymer 0.01%wt (100ppm) with salinity 40000 ppm (201-1826 days)	60.1
HS-P1SAL1	HS (200 days) + Polymer 0.1%wt (1000ppm) with salinity 1000 ppm (201-1826 days)	68.1
HS-P1SAL40	HS (200 days) + Polymer 0.1%wt (1000ppm) with salinity 40000 ppm (201-1826 days)	60.2

The oil recovery, oil production rate, water-cut profile and field pressure results of SP flooding are shown in Fig.4.43, Fig.4.44, Fig.4.45 and Fig.4.46. It is clearly seen that the results is in pair of changing surfactant concentration with the same polymer concentration and salinity in the solution. In case of polymer 1%wt concentration, the field pressure decreases significantly that could give negative effect to the reservoir formation. The interesting point is the case having highest oil recovery is not the high concentration in chemical concentration, but it is the case with low surfactant concentration (1%wt), high polymer concentration (0.1%wt) and low salinity (1000ppm).

The comparison of oil recovery between using surfactant flooding, polymer flooding and SP flooding as the second recovery phase varied chemical concentration and salinity in the solution shown in Fig.4.47

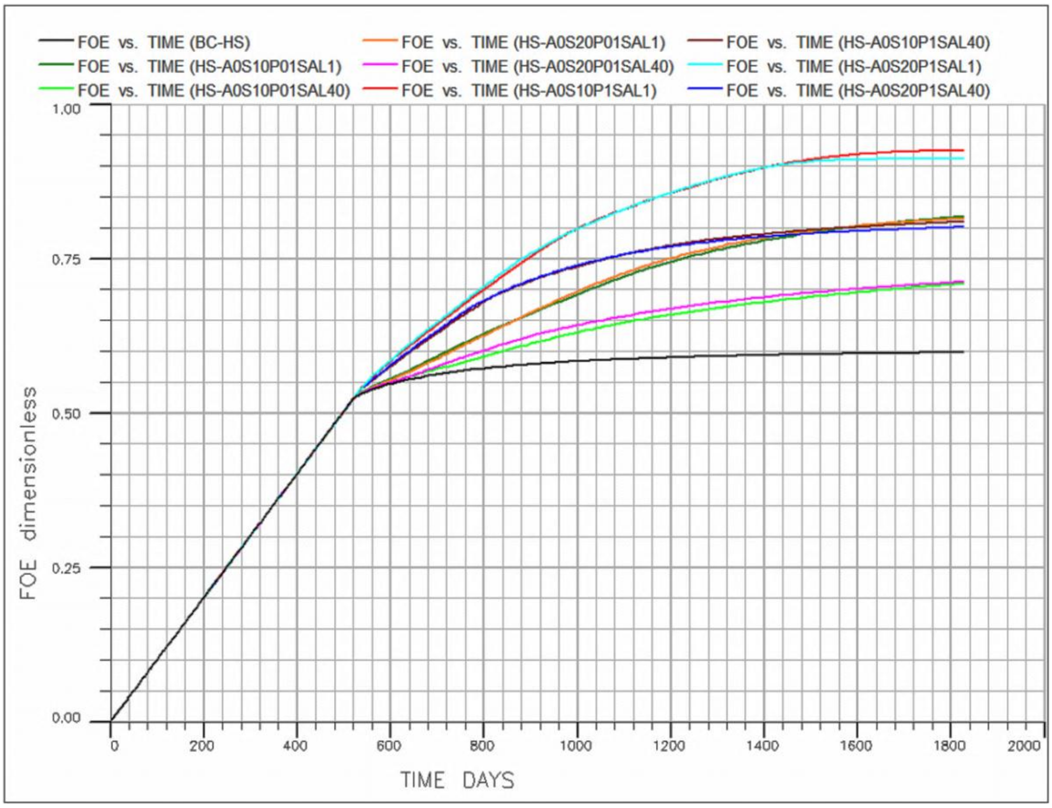


Figure 4. 43 The oil recovery of combination of low salinity and SP flooding

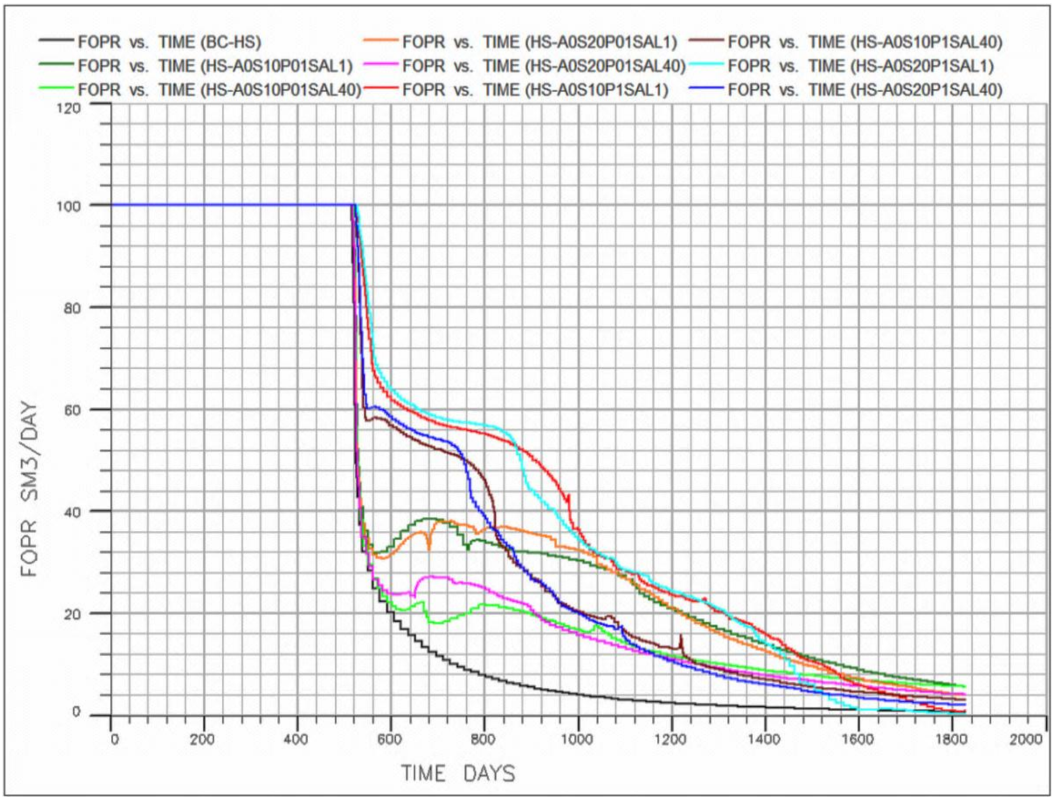


Figure 4. 44 The oil production rate of combination of low salinity and SP flooding

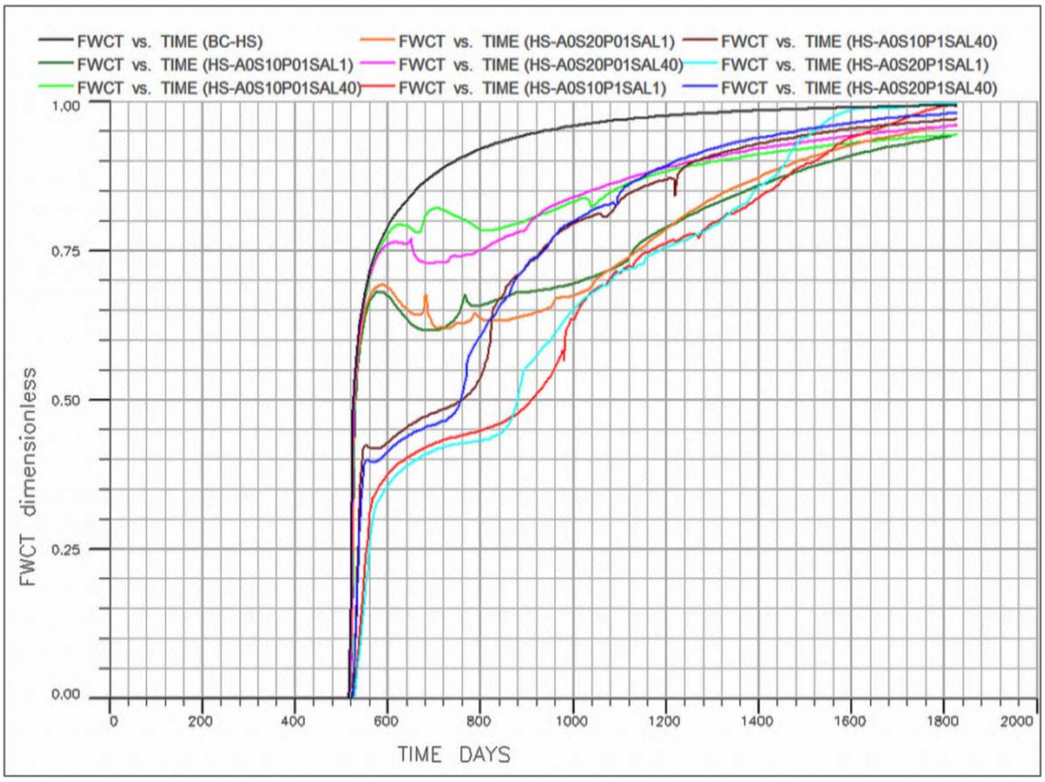


Figure 4. 45 The water-cut of combination of low salinity and SP flooding

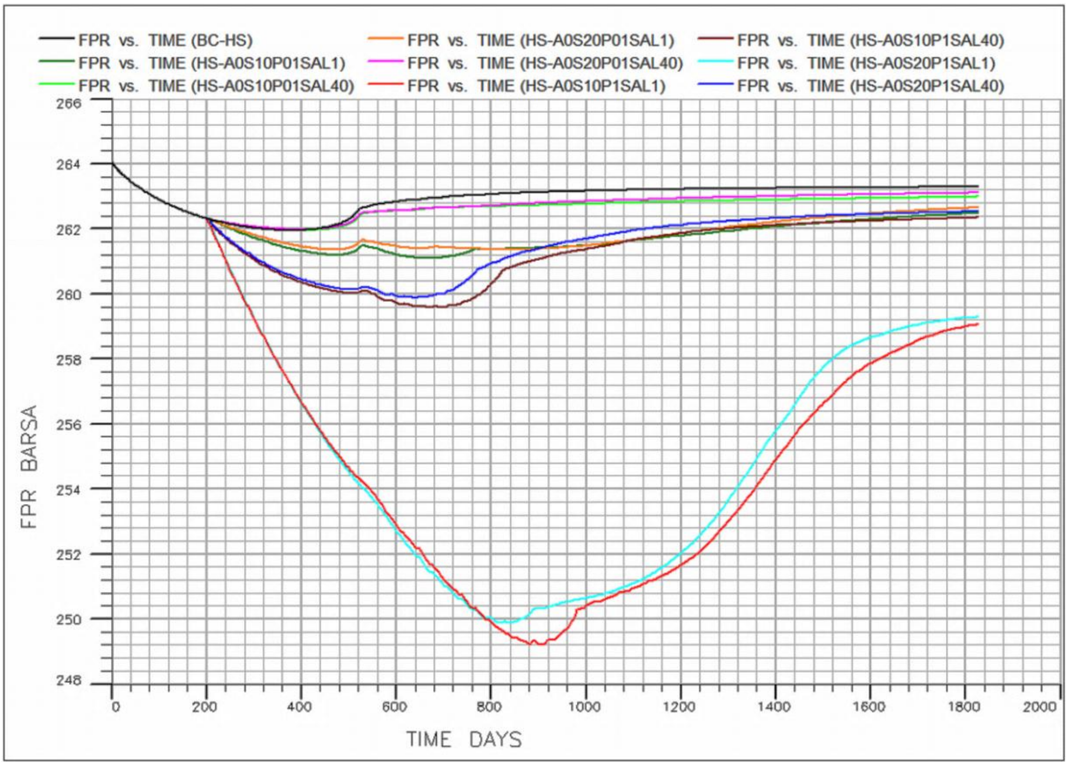


Figure 4. 46 The field pressure profile of combination of low salinity and SP flooding

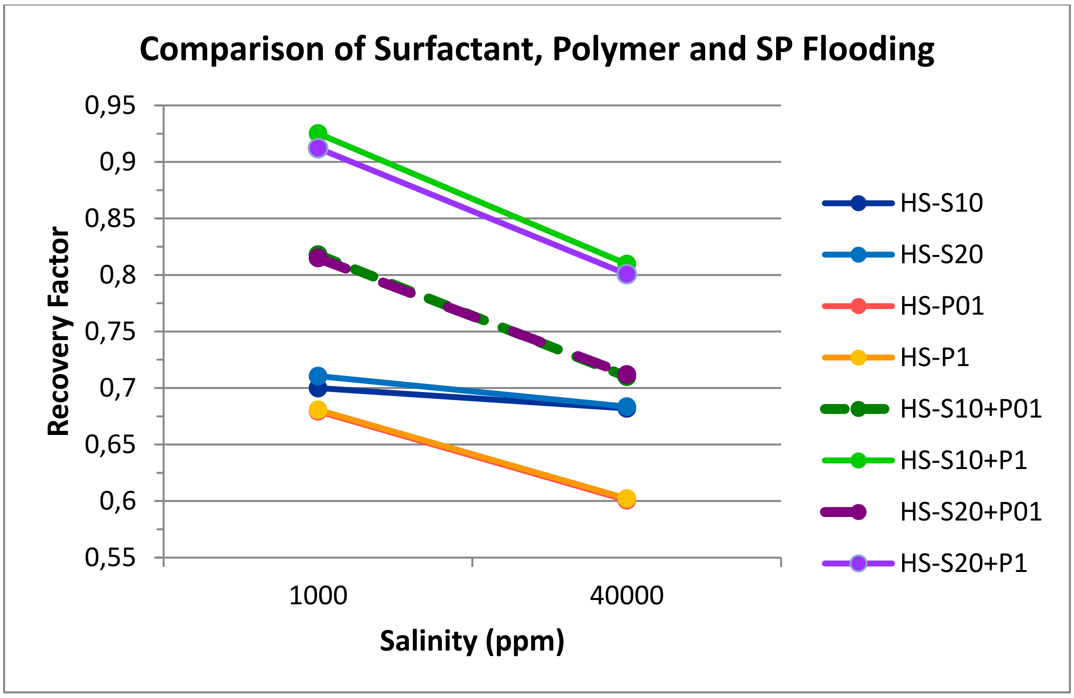


Figure 4. 47 The comparison of oil recovery between using the surfactant flooding, the polymer flooding and SP flooding varying chemical concentration and salinity (HS-S10/S20 = surfactant flooding, HS-P01/P1 = polymer flooding and HS-S10+P01 = SP flooding)

4.2.5.3.1 Effect of surfactant concentration to SP flooding

The varying of surfactant concentration in SP solution is compared to the pure polymer solution is use in study of surfactant effect to SP flooding, From Fig.4.47, it can be indicated that adding surfactant to polymer solution can cause greatly increasing oil recovery. Particularly, the oil recovery between low and high polymer concentration without surfactant are similar but it is clearly different to each other when adding surfactant. However, at the same polymer concentration, higher surfactant concentration does not effect to much different in oil recovery. As discussing in the surfactant flooding and in AS flooding part, the surfactant concentration 2%wt concentration is over CMC ; thus the recovery of the cases with surfactant concentration 2%wt are not largely different from 1%wt. Thereby, surfactant impacts strongly to SP flooding but in case of optimum surfactant concentration.

In generally, Surfactant slugs are frequently used to mobilize residual oil by reducing IFT. Sheng (2011) examined the effect of surfactant to polymer flooding that adding surfactant results decreasing viscosity of HPAM. It is suggested that anionic surfactants affect the viscosity behavior of HPAM through the charge shielding mechanism, which causes the shrinkage of molecular chains of polymer and the decrease of hydrodynamic radius, resulting lower polymer solution viscosity.

From polymer flooding study in section 4.2.4, the summary shows that the combination of low salinity and high polymer can cause too high viscosity that move difficultly and block the permeability in the reservoir. This reason above supports our result that the surfactant can reduce the too high viscosity and make it flows easier, while still keeping viscosity higher than using low polymer concentration. Therefore, apart from IFT reduction, surfactant in SP solution also improves the sweep efficiency effect of SP flooding. However, surfactant 2%wt is too high, and then does not affect much differently from surfactant 1%wt concentration.

4.2.5.3.2 Effect of polymer concentration to SP flooding

Effect of polymer concentration to SP flooding can be studied by varying of polymer concentration in SP solution and comparing to the pure surfactant solution. From Fig.4.47, it can be seen that addition of polymer in pure surfactant solution can increase oil recovery as same as increase polymer concentration in SP solution.

Polymer flooding, in generally, is used for increase viscosity of flooding solution; thus improving sweep efficiency. Trushenski (1977) evaluated the effect of polymer on the surface properties that polymer increases the surface tension of the surfactant solution due to interaction of the functional group of both polymer and ionic surfactant.

Even though, polymer results negatively to surfactant solution, the increasing of polymer in this test still enhance better oil recovery. It means that this negative effect should influence to the oil recovery less than the positive effect of improved sweep efficiency.

4.2.5.3.3 Effect of salinity in chemical solution to SP flooding

The salinity in chemical solution effect is studied by comparing high salinity and low salinity while controlling the same chemical types and concentration. Low salinity can improve significantly oil recovery compared to high salinity in every condition of SP solution.

For polymer, Han et al.(1999) summed that the polymer solution viscosity decrease with NaCl concentration due to the increasing of ionic strength and ionic shield that results to decreasing of elastic modulus and relaxation time. For surfactant, Hirasaki (1983) concluded that at Type III salinity conditions, surfactant results to lowest IFT and surfactant trapped in the residual oil phase can begin mobilizing. Therefore, low salinity influence in positive effect for both polymer and surfactant flooding.

Due to the combination effect that surfactant reduces polymer solution viscosity, it can be advantage to the high polymer concentration, whereas disadvantage to low polymer concentration. Though, the optimum surfactant concentration is considered importantly. The presence of polymer also increases IFT of surfactant solution. However, the result in this test shows that the surfactant main effect as reducing IFT and the polymer main effect as improving sweep efficiency can still perform well as the oil recovery of SP flooding are better than only surfactant flooding and only polymer flooding itself. Low salinity is still preferable in all aspects.

4.2.5.4 Summary

In summary, low salinity in chemical solution influences a positive effect to oil recovery in every case, although it gives different impacts to each type of chemical flooding. Mainly, low salinity increases polymer solution viscosity that can improve sweep efficiency of polymer flooding. In alkaline flooding and surfactant flooding, the salinity is need to be optimized to optimum salinity condition corresponding to optimum alkaline concentration and surfactant concentration, where creates the lowest IFT.

In term of effect between each chemical flooding, alkaline does not strongly affect to polymer directly, while can combined with surfactant to establish the ultralow IFT condition, which can reduce amount of surfactant required to reach the same performance. Between polymer and surfactant, polymer can increase IFT of surfactant solution, whereas surfactant can decrease viscosity of polymer concentration. However, the combined effect should be balanced with the single chemical flooding effect as reducing IFT by alkaline flooding and surfactant flooding and increasing sweep efficiency by polymer flooding.

4.3 Tertiary Recovery Phase

For the tertiary recovery phase part, the best cases from each method that were discussed in the previous part were brought to study. Only water flooding was used in the tertiary phase. There are 2 main topics that are interested in this part for each method: effect of range of secondary recovery phase and effect of salinity in tertiary flooding: HS and LS. The ranges of secondary flooding study for each case were different corresponding oil production rate results from the previous part.

4.3.1 Low salinity water flooding

In Low salinity water flooding part, that there was no study in effect of salinity in tertiary flooding for low salinity water flooding case because low salinity is injected as slug in secondary phase and continued only by HS in tertiary phase. From section 4.2.1, HS-LS case was selected for tertiary flooding study. This case had beginning by HS flooding from the first day until 200 days of production, followed by continuous LS flooding through production life, totally 1626 days of LS injection and gives 64.3% oil recovery.

In this part, LS is used for two limited range: 680 days (HS-LS-HS) and 880 days (HS-LS-HS-2) LS injection. Both cases were followed by HS until end of production. Comparing these two cases with HS-LS case, the HS-LS case has approximately double of injection range. Table 4.9 summarizes short details and oil recovery of all cases used in this part.

Table 4. 9 The short details and oil recovery all cases used in LS flooding in tertiary phase recovery study

Name	Details	Recovery (%)
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
HS-LS	HS (0-200 days) + LS continuing (201-1826 days)	64.3
HS-LS-HS	HS (0-200 days) + LS slug 680 days (201-880 days) + HS (881-1826 days)	63.2
HS-LS-HS-2	HS (0-200 days) + LS slug 880 days (201-1080 days) + HS (1081-1826 days)	64.0

4.3.1.1 Effect of range of second recovery phase

The oil recovery and oil production rate of tertiary water flooding can be seen in Fig.4.48 The oil recoveries have the same trend until about 1200 production days that the differences of results are noticeable. After the HS water breakthrough at about 513 days, oil production rates in all cases decrease rapidly until 730 days and keep constant for a while, and then continue going down slightly. At 1200 production days, we can see that oil production rate of the shortest slug size case (680 days) drops from the others resulting oil recovery does not increase much from that point till end of production. That point is expected to be the breakthrough point of tertiary flooding effect. The breakthrough point of 880 days LS slug size is at 1500 days. The end value of oil production rate of continuous LS injection (HS-LS) is still higher than the other cases that are quite the same. However, oil recovery of 880 days slug size is very close to the HS-LS case that is double of injection range. The HS-LS has incremental oil recovery 1.1% and only 0.3% higher than 680 and 880 days LS slug injection, respectively, whereas, all cases are better than BC-HS.

It can be summarized that if the oil produced from the wettability changing effect reaches the breakthrough, the production would start to drop obviously. So, the longer range of secondary phase injection, the higher oil recovery. However at a certain injection range, the breakthrough point occurs late enough to cause indifferent oil recovery. Therefore, in tertiary recovery phase study of LS flooding, HS-LS-HS-2 would be the best case due to double shorter of LS injection range, thus double less LS injection amount, but give almost the same oil recovery, which is 64%, to the continuous LS injection till end of production life.

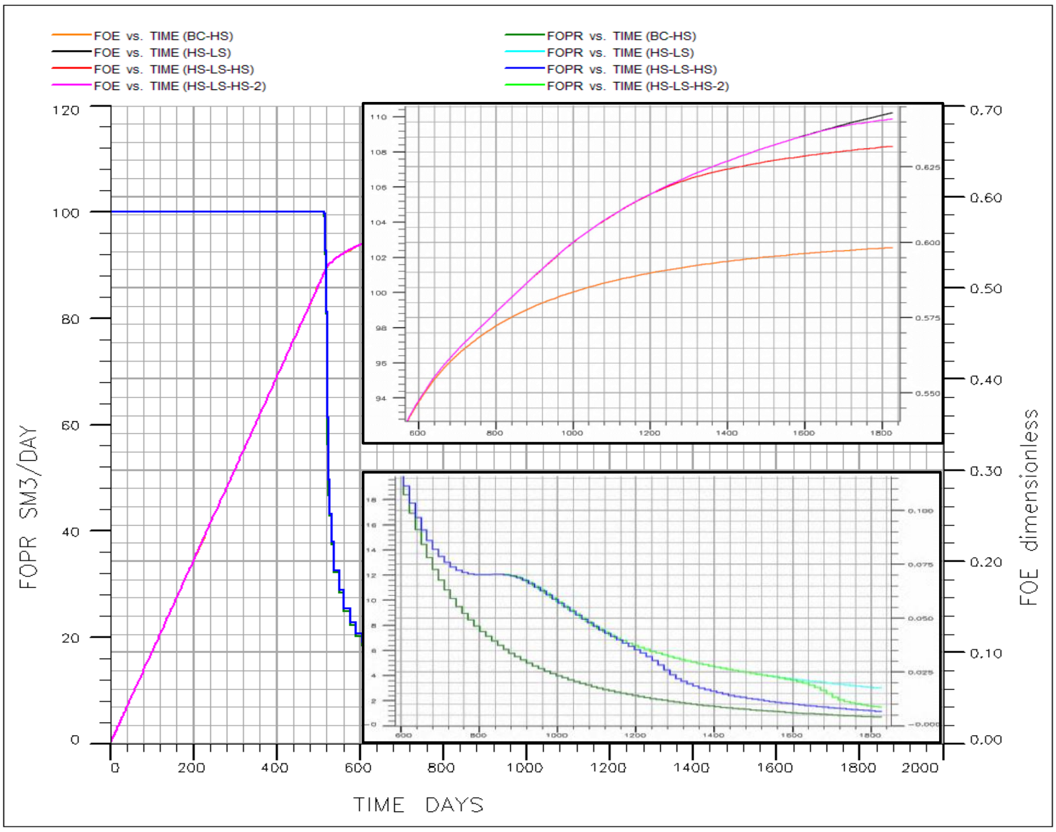


Figure 4. 48 The oil recovery and oil production rate profile of tertiary phase study of low salinity water flooding

4.3.2 Combination of low salinity water flooding and alkaline flooding

As discussing in section 4.2.2, HS-A30SAL1 case was selected for tertiary flooding study. HS flooding was used from the first day until 200 days of production, and then followed by continuous alkaline flooding with 3% concentration and 1000 ppm salinity through production life, totally 1626 days of alkaline flooding and gives 68.7% oil recovery.

From oil production rate of HS-A30SAL1 case, which is shown in Fig.4.11, the rate starts to be constant at 800 days of production and fall down slowly from 900 days till end of production. Consequently, three ranges were used in this sensitivity: 600 days, 800 days and 1000 days of alkaline injection as secondary recovery phase and continued by either HS or LS flooding until the last production day as tertiary recovery phase. It is noted that alkaline solution through this part is meant alkaline 3%wt concentration with salinity 1000 ppm. The short details and oil recovery of all cases used in this part are concluded in Table 4.10.

Table 4. 10 The short details and oil recovery all cases used in the combination of LS and alkaline flooding in tertiary phase recovery study

Name	**Details**	**Recovery (%)**
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
HS-LS	HS (0-200 days) + **LS continuing (201-1826 days)**	64.3
HS-A30SAL1	HS (0-200 days) + **Alkaline 3%wt with** salinity 1000 ppm (201-1826 days)	68.7
HS-A30SAL1-HS	HS (0-200 days) + **Alkaline slug 600 days** (201-800 days) +HS 1026 days (801-1826 days)	68.5
HS-A30SAL1-LS	HS (0-200 days) + **Alkaline slug 600 days** (201-800 days) +LS 1026 days (801-1826 days)	69.3
2-HS-A30SAL1-HS	HS (0-200 days) + **Alkaline slug 800 days** (201-1000 days) +HS 826 days (1001-1826 days)	67.5
2-HS-A30SAL1-LS	HS (0-200 days) + **Alkaline slug 800 days** (201-1000 days) +LS 826 days (1001-1826 days)	68.9
3-HS-A30SAL1-HS	HS (0-200 days) + **Alkaline slug 1000 days** (201-1200 days) +HS 626 days (1201-1826 days)	69
3-HS-A30SAL1-LS	HS (0-200 days) + **Alkaline slug 1000 days** (201-1200 days) +LS 626 days (1201-1826 days)	69.4

Results of oil recovery are presented in Fig.4.49. The changing of oil recovery, which is rising quickly after getting the effect and slowing down after the breakthrough, in the shorter injection range take place sooner than the longer injection range. Both effects of injection range and salinity influence significant to oil recovery as we can see that there is no apparently trend to define the higher oil recovery. However, some cases with tertiary phase give better recovery than the continuous alkaline flooding case. 3-HS-A30SAL1-LS, HS-A30SAL1-LS and 3-HS-A30SAL1-HS give 0.7%, 0.6%, 0.3% and 0.2%, respectively, incremental oil production, while 2-HS-A30SAL-LS, HS-A30SAL1-HS and 2-HS-A30SAL1-HS give 0.2%, 0.2% and 1.2% less oil production from continuous alkaline flooding case.

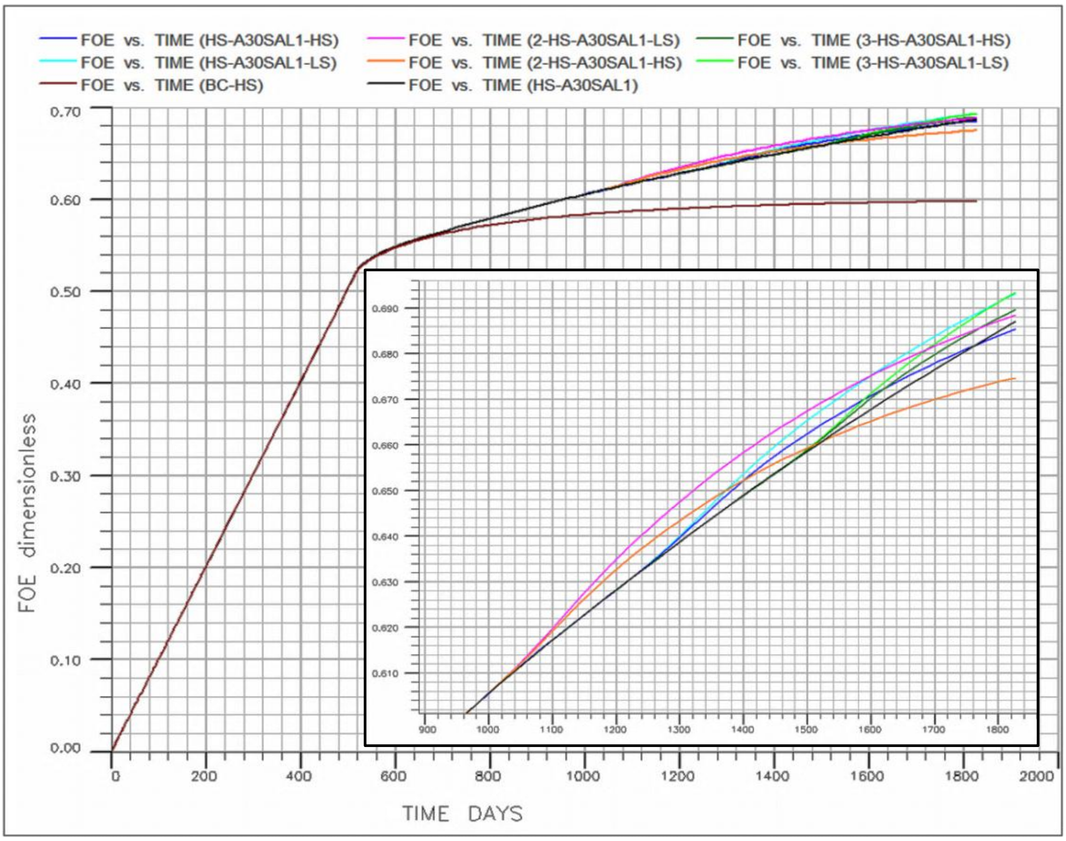


Figure 4. 49 The oil recovery of tertiary phase study of the combination of low salinity water flooding and alkaline flooding

From Fig.4.50, the oil production rates follow the same trend until 680 days of production. After that, in case of continuous alkaline flooding, oil production becomes constant but with lower rate than the other cases before it reaches effect breakthrough at 900 days and oil production rate fall gradually through the end of field. In case of the same range of injection (different salinity), each injection range still has the same trend but occur at different time. After 680 days, the trend of oil production rate keeps decline slowly for a while before builds up and reaches a certain peak, and then go down readily. The rates from the shorter injection range reach the peak faster, resulting the lower final oil production rate even the rates decline with the same slope. Comparing between HS and LS in the same range, LS flooding in each injection range delays the rate because it reached the higher peak than HS flooding case.

This phenomenon can be explained by firstly the delay of alkaline effect in the system. Another reason, after the alkaline effect reaches its breakthrough, the diffusion of the in-situ surfactants into the aqueous phase decrease and the surfactants still remains at the oil/water interface, hence the mobilized trapped oil decrease. The water injection can improve sweep efficiency of surfactant remaining in the reservoir and also shift the more trapped oil, thus we see the oil production rate increases after injecting water behind alkaline flooding.

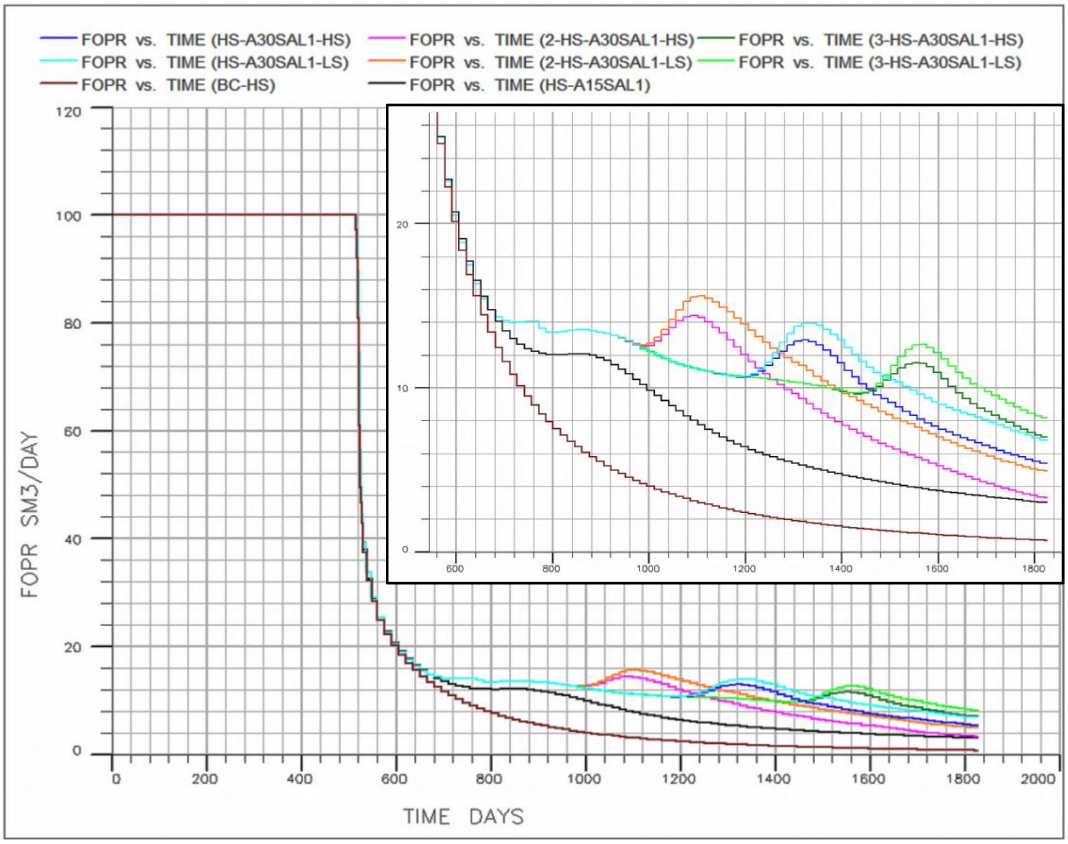


Figure 4. 50 The oil production rate of tertiary phase study of the combination of low salinity water flooding and alkaline flooding

Water-cut can be seen in Fig.4.51. The trend of water cut result is in the opposite direction of oil production rate.

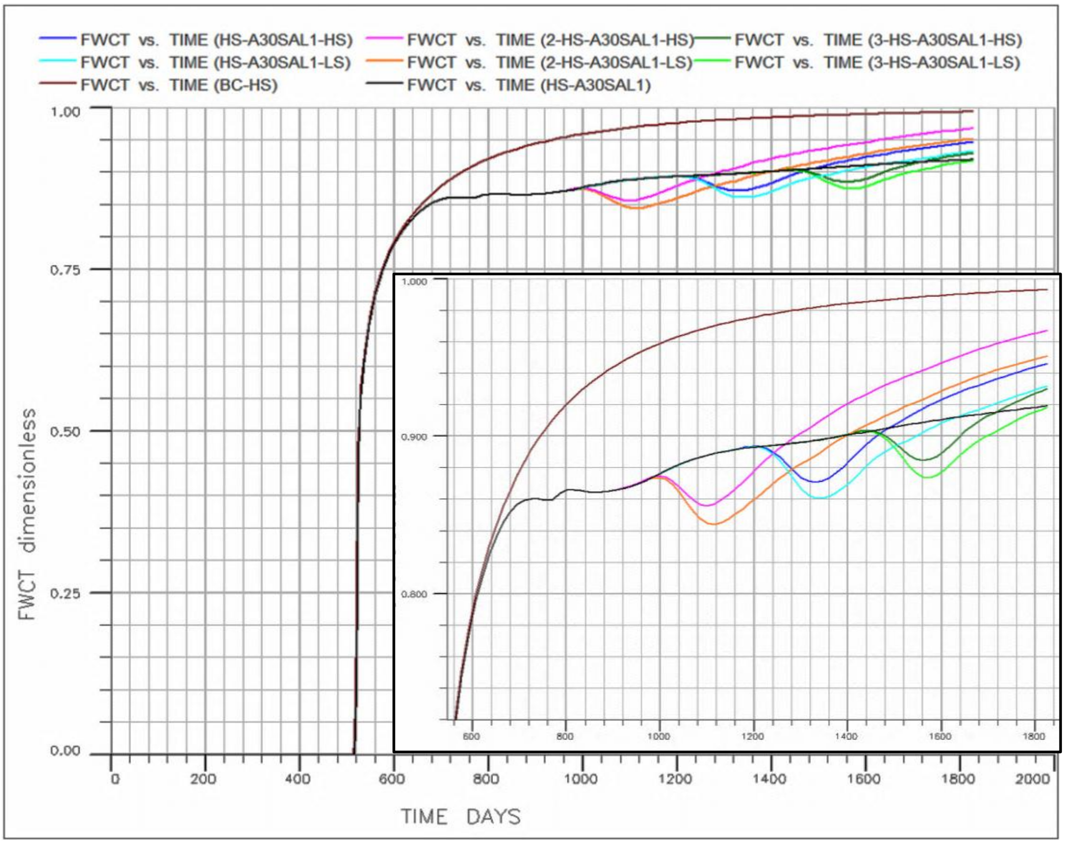


Figure 4. 51 The water-cut profile of tertiary phase study of the combination of low salinity water flooding and alkaline flooding

4.3.2.1 Effect of range of second recovery phase

Fig 4.52 presents oil recovery of all cases varied range of secondary recovery phase and salinity of water flooding in tertiary recovery phase. Comparing the injection range with the same type of flooding from the figure, the longer injection period affects the higher oil recovery in both HS and LS case. This is because amount of alkaline is used more in the longer injection period and the effect can continue to change IFT. However, when the effect achieves the optimum threshold, it cannot longer influence the system.

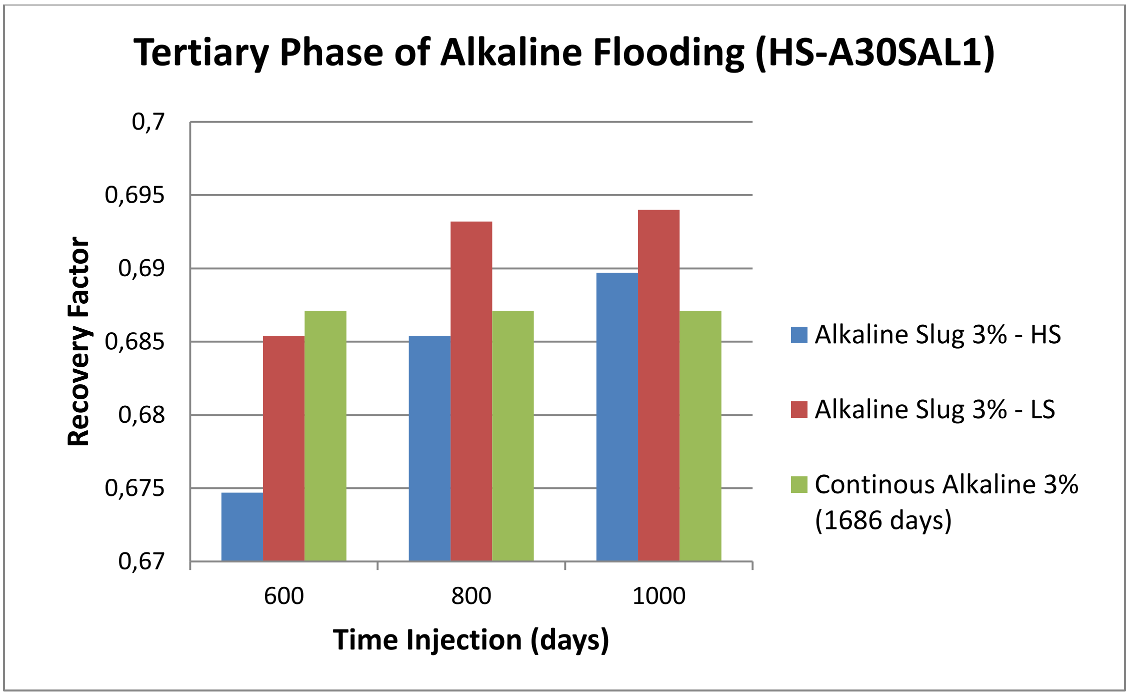


Figure 4. 52 The oil recovery of all cases varied range of secondary recovery phase and salinity of water flooding in tertiary recovery phase (alkaline flooding study)

4.3.2.2 Effect of salinity in tertiary recovery phase

From Fig.4.52, it is seen clearly that LS flooding in the tertiary phase results better than HS flooding in the same range. After the in-situ surfactant reduces IFT between oil and water, more oil is recovered. However, the influence of surfactant decreases along the production time. Then, LS injection can change the system become more water-wet. Accordingly, more oil can be produced including mobilized trapped oil from the IFT effect. Moreover, the alkaline effect is supposed to be encouraged from wettability changing effect.

4.3.2.3 Summary

In combination of low salinity water and alkaline flooding, both injection ranges of secondary phase and salinity impact essentially to the tertiary phase because if we optimize them properly, we can get higher oil recovery whereas cheaper cost. Salinity seems to influent to the recovery more than the injection range. In this study, the best case can be the case with 800 days alkaline flooding (3%wt-1000ppm salinity) followed by LS flooding as tertiary phase *(HS-A30SAL1-LS)* because it gives oil recovery almost the same as 1000 injection days and higher than the continuous alkaline flooding.

4.3.3 Combination of low salinity water flooding and surfactant flooding

From the discussion in section 4.2.3, HS-S10SAL1 case was chosen for studying in tertiary recovery phase. Since the first day of production, HS flooding was used until 200 days and afterward followed by continuous surfactant flooding with 1% concentration and 1000 ppm salinity through production life, totally 1626 days of surfactant flooding and gives 70% oil recovery.

Considering oil production rate of HS-S10SAL1 case, which is shown in Fig.4.17, after water breakthrough, the rate keeps falling down quickly until 680 days and then continues slowly declining through the production. Accordingly, four ranges were studied in this sensitivity: 400 days, 600 days, 1000 days and 1200 days of surfactant injection in secondary recovery phase and continued by either HS or LS flooding until end of production as tertiary recovery phase. The word surfactant solution in this part is meant surfactant 1%wt concentration with salinity 1000 ppm. Table 4.11 shows the short details and oil recovery of all cases used in this part.

Oil recovery result is shown in Fig.4.53. From the figure, it can be noticed that the effect takes place earlier in the shorter injection range than the longer injection range. Some case of the shorter injection period gives higher oil recovery than the longer range and the continuous surfactant flooding, however some cases do not. This is depended on the optimum injected surfactant volume and optimum salinity in the system. 2-HS-S10SAL1-LS (600days/LS) results 1% incremental oil production, while HS-S10SAL1-LS (1000days/LS), 3-HS-S10SAL1-LS (1200days/LS) and 3-HS-S10SAL1-HS (1200days/HS) give the same production and HS-S10SAL1-HS, 4-HS-S10SAL1-LS, 2-HS-S10SAL1-HS and 4-HS-S10SAL1-HS have 0.1%, 0.3%, 0.8% and 1.6% less oil production from the continuous surfactant flooding.

Table 4. 11 The short details and oil recovery of all cases used in the combination of LS and S flooding in tertiary phase recovery study

Name	Details	Recovery (%)
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
HS-LS	HS (0-200 days) + LS continuing (201-1826 days)	64.3
HS-S10SAL1	HS (0-200 days) + **Surfactant 1%wt with salinity 1000 ppm** (201-1826 days)	70.0
HS-S10SAL1-HS	HS (0-200 days) + **Surfactant slug 1000 days** (201-1200 days) +HS 626 days (1201-1826 days)	69.9
HS-S10SAL1-LS	HS (0-200 days) + **Surfactant slug 1000 days** (201-1200 days) +LS 626 days (1201-1826 days)	70.0
2-HS-S10SAL1-HS	HS (0-200 days) + **Surfactant slug 600 days** (201-800 days) +HS 1025 days (801-1826 days)	69.2
2-HS-S10SAL1-LS	HS (0-200 days) + **Surfactant slug 600 days** (201-800 days) +LS 1025 days (801-1826 days)	70.1
3-HS-S10SAL1-HS	HS (0-200 days) + **Surfactant slug 1200 days** (201-1400 days) +HS 426 days (1401-1826 days)	70.0
3-HS-S10SAL1-LS	HS (0-200 days) + **Surfactant slug 1200 days** (201-1400 days) +LS 426 days (1401-1826 days)	70.0
4-HS-S10SAL1-HS	HS (0-200 days) + **Surfactant slug 400 days** (201-600 days) +HS 1225 days (601-1826 days)	68.5
4-HS-S10SAL1-LS	HS (0-200 days) + **Surfactant slug 400 days** (201-600 days) +LS 1225 days (601-1826 days)	69.7

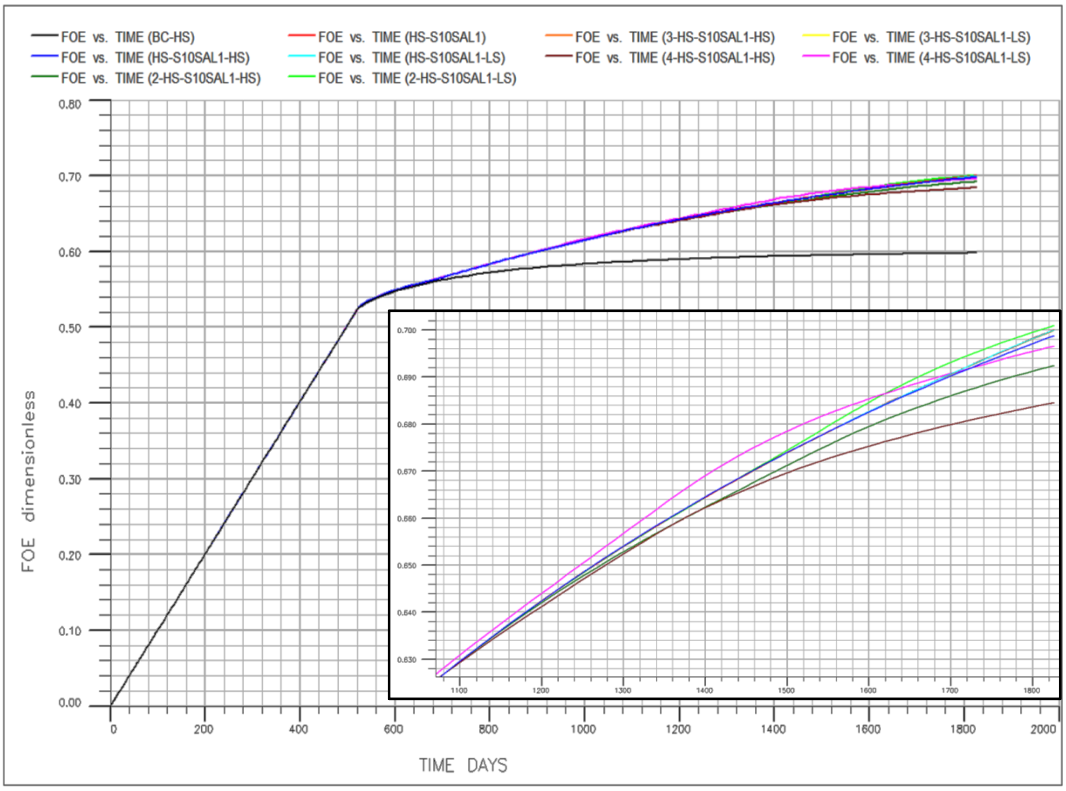


Figure 4. 53 The oil recovery of tertiary phase study of the combination of low salinity water flooding and surfactant flooding

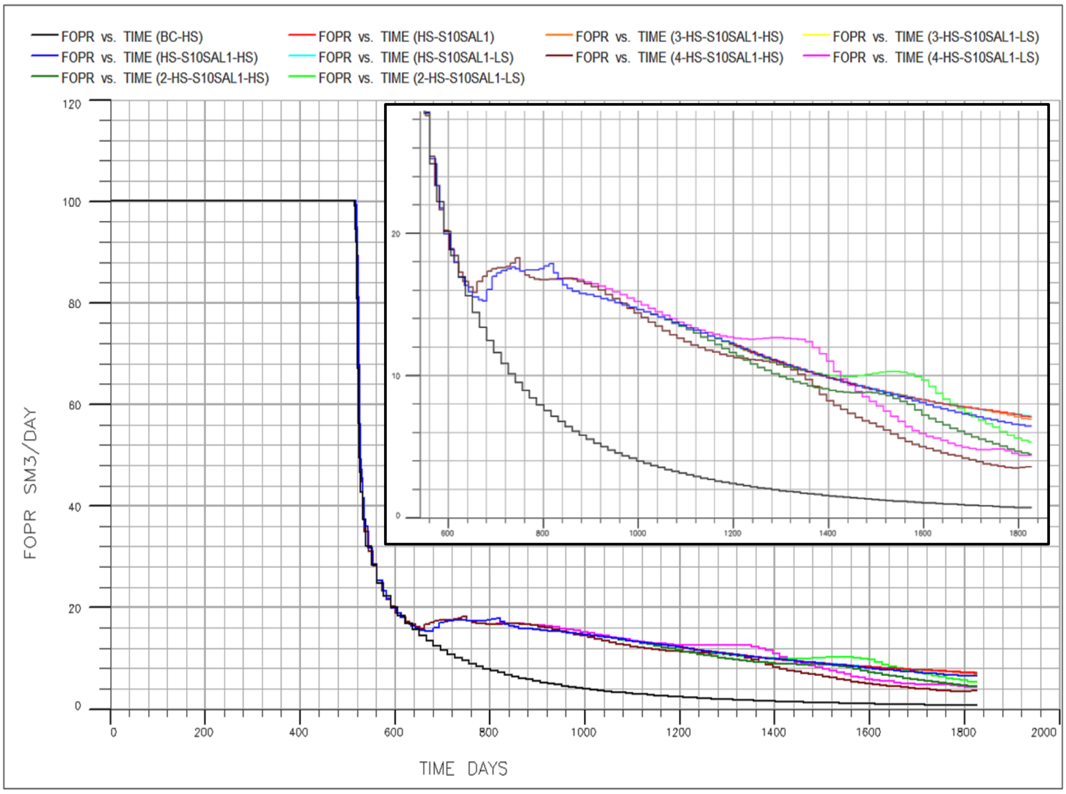


Figure 4. 54 The oil production rate of tertiary phase study of the combination of low salinity water flooding and surfactant flooding

From Fig.4.54, oil production rates have the same trend until 660 days that the 400 days range cases start to increase again earlier than the others, which increase at 680 days of production. After all case rise up and reach their peak, they keep declining slowly. There is a short constant production rate period at 1200 days and 1400 days for case 400 days and 600 days surfactant injection range, respectively, whereas the others do not have including the continuous surfactant flooding.

It is supposed that the first increasing oil rate should come from the effect of remained surfactant in the reservoir but because the case 400 days surfactant injection has changed to be water flooding at 600 production days, thus the effect starts earlier than the others. The second peak can be caused by water driving efficiency that can sweep either hided oil or surfactant and also desorb some surfactant from the rock surface. This effect can be defined approximately 600 days from the day stopping surfactant injection and change to be water flooding. The reason supporting the explanation above is that this effect would impact to the longer surfactant flooding cases too close to the end of production life, hence we cannot see for the 1000 days and 1200 days range cases but we do in the earlier water flooding cases.

The trend of water-cut results can be remarked as same as oil production rate result but in advert direction. It can be also clarified by the same reason.

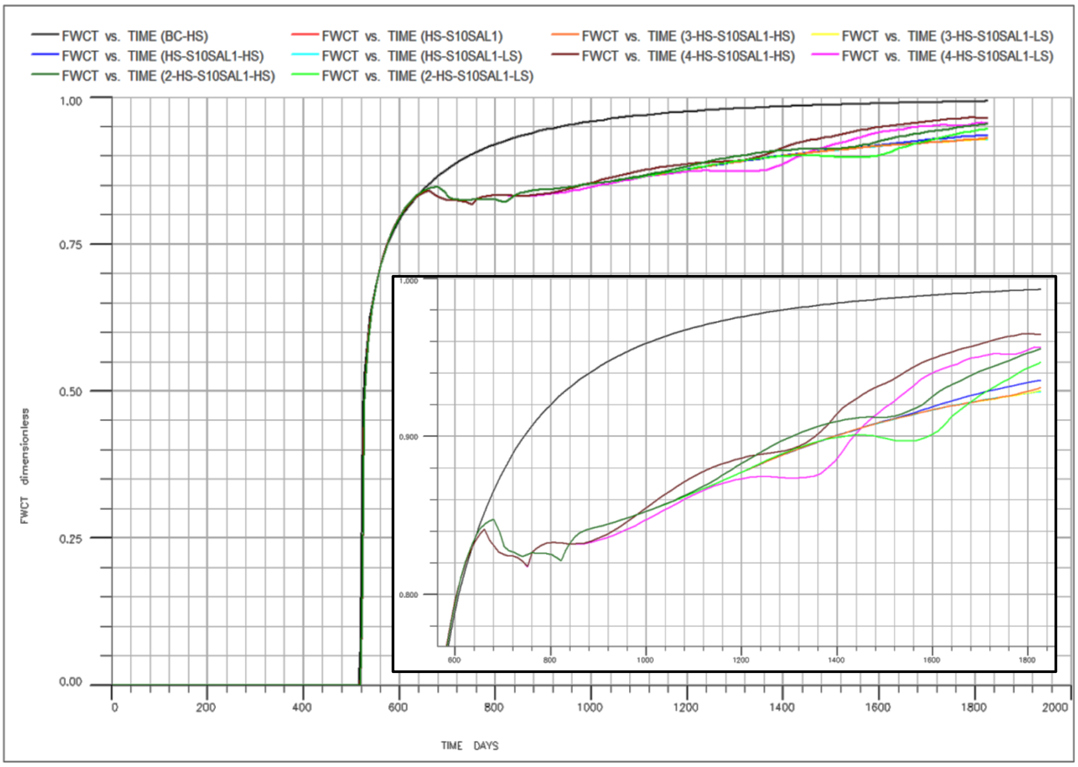


Figure 4. 55 The water-cut of tertiary phase study of the combination of low salinity water flooding and surfactant flooding

4.3.3.1 Effect of range of second recovery phase

The comparison of oil recovery from all cases varied range of secondary recovery phase and salinity of water flooding in tertiary recovery phase is illustrated in Fig.4.56. Comparing the injection range with the same type of flooding, the longer injection period influences higher oil recovery in both HS and LS case. However, as closer to 1200 days range, the increasing of oil recovery drops slightly. This can be proposed that from 1000 days of surfactant injection, surfactant concentration starts to become above CMC point and causes IFT does no longer affect to the system, particularly when flooding by LS.

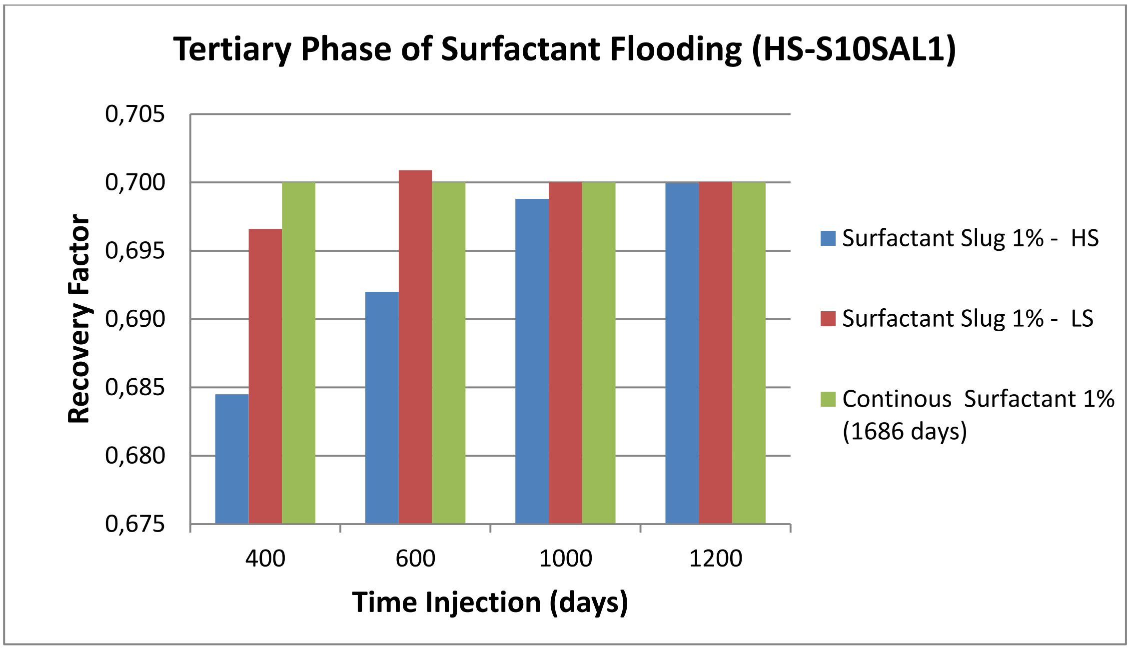


Figure 4. 56 The oil recovery of all cases varied range of secondary recovery phase and salinity of water flooding in tertiary recovery phase (surfactant flooding study)

4.3.3.2 Effect of salinity in tertiary recovery phase

It is seen apparently that LS flooding in the tertiary phase results better than HS flooding in the same range. However, the reason that the optimum surfactant concentration with optimum salinity is the condition to get the highest recovery can be used to support this result. This means that the case with 600 days of surfactant injection and followed by LS flooding can create the optimum condition of this model. The shorter or longer surfactant injection period can cause over concentration and the higher salinity can cause over salinity condition.

4.3.3.3 Summary

This part has shown that injection ranges of secondary phase and salinity impact obviously to the tertiary phase combination of low salinity water and surfactant flooding. The main issue is optimum surfactant concentration and optimum salinity play a significant role, hence; optimization of these two factors is very important. The best case in this study can be the case with 600 days surfactant flooding (1%wt-1000ppm salinity) followed by LS flooding as tertiary phase *(2-HS-S10SAL1-LS)* because its recovery is even higher than the continuous surfactant flooding, while the cost of surfactant solution is less.

4.3.4 Combination of low salinity water flooding and polymer flooding

In the part, the case HS-P01SAL1, which was selected from section 4.2.4, is discussed for tertiary recovery phase. From the beginning, HS was injected until 200 days and then followed by continuous polymer flooding with 0.01% (100 ppm) concentration and 1000 ppm salinity through production life, totally 1626 days of surfactant flooding and gives 67.9% oil recovery.

From oil production rate of HS-P01SAL1 case, which is shown in Fig., after water breakthrough, the rate declines very fast until about 1200 production days that oil is no longer produced. This means that for polymer, it stops producing early and this results to the selected injection range for tertiary recovery phase. Therefore, two ranges were studied in this sensitivity: 200 days and 400 days of polymer injection in secondary recovery phase and continued by either HS or LS flooding until end of production as tertiary recovery phase. Polymer solution in this part is stood for polymer 0.01%wt concentration with salinity 1000 ppm. The short details and oil recovery of all cases used in this part are shown in Table 4.12.

Table 4. 12 The short details and oil recovery all cases used in the combination of LS and P flooding in tertiary phase recovery study

Name	**Details**	**Recovery (%)**
BC-HS	HS Water Flooding with 40,000 ppm continuing (0-1826 days)	58.8
HS-LS	HS (0-200 days) + LS continuing (201-1826 days)	64.3
HS-P01SAL1	HS (0-200 days) + **Polymer 0.01%wt with salinity 1000 ppm** (201-1826 days)	67.9
HS-P03SAL1	HS (0-200 days) + **Polymer 0.03%wt with salinity 1000 ppm** (201-1826 days)	68.1
HS-P1SAL1	HS (0-200 days) + **Polymer 0.1%wt with salinity 1000 ppm** (201-1826 days)	68.1
HS-P01SAL1-HS	HS (0-200 days) + **Polymer 0.01%- 200 days** (201-400 days) +HS 1225 days (401-1826 days)	62.5
HS-P01SAL1-LS	HS (0-200 days) + **Polymer 0.01%- 200 days** (201-400 days) +LS 1225 days (401-1826 days)	65.7
2-HS-P01SAL1-HS	HS (0-200 days) + **Polymer 0.01%- 400 days** (201-600 days) +HS 1225 days (601-1826 days)	64.4
2-HS-P01SAL1-LS	HS (0-200 days) + **Polymer 0.01%- 400 days** (201-600 days) +LS 1225 days (601-1826 days)	66.6
HS-P03SAL1-LS	HS (0-200 days) + **Polymer 0.03%- 200 days** (201-400 days) +LS 1225 days (401-1826 days)	66.7
2-HS-P03SAL1-LS	HS (0-200 days) + **Polymer 0.03%- 400 days** (201-600 days) +LS 1225 days (601-1826 days)	67.4

Fig.4.57 shows oil recovery result. It can be demonstrated that the continuous polymer flooding gives still higher oil recovery than the polymer slug and water flooding. Although the range of polymer flooding impact to oil recovery, the salinity of water flooding in tertiary phase is also important. However, there are not very big differences as the cumulative oil production of 2-HS-P01SAL1-LS, HS-P01SAL1-LS, 2-HS-P01SAL1-HS and HS-P01SAL1-HS cases are less than the continuous polymer injection 1.3%, 2.2%, 3.5% and 5.4%, respectively.

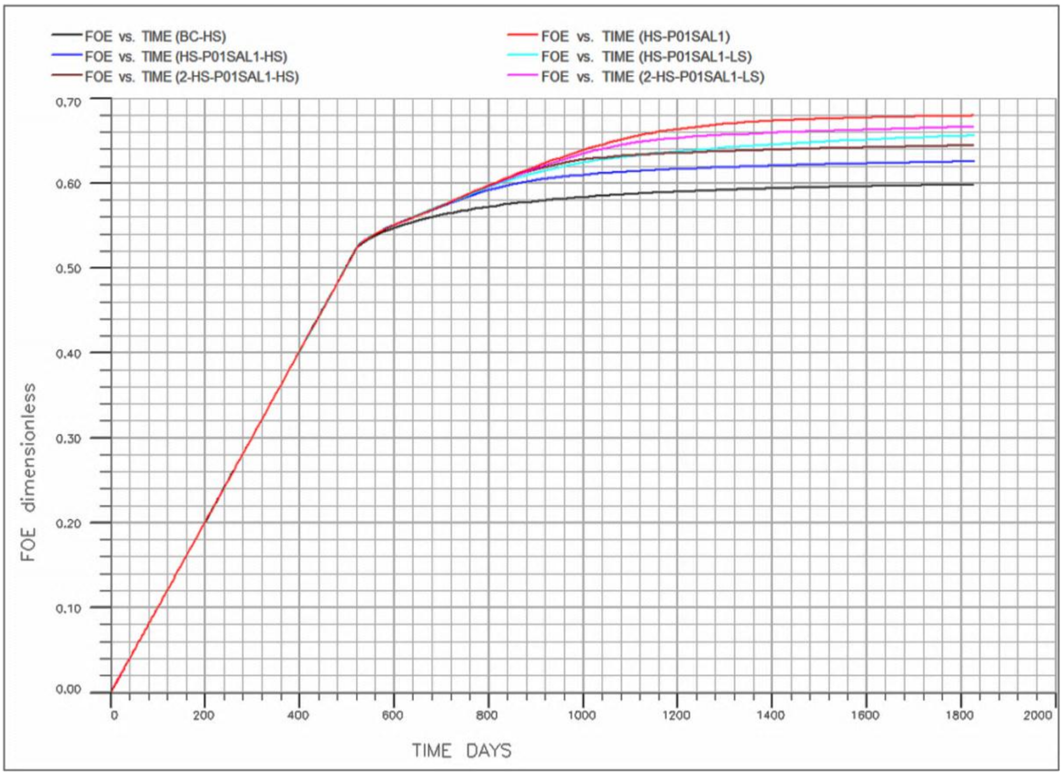


Figure 4. 57 The oil recovery of tertiary phase study of the combination of low salinity water flooding and polymer flooding

Oil production rate and wate-cut profiles are shown in Fig.4.58 and Fig.4.59. All cases have the same trend that is the water breakthrough happen at 513 days and then oil keep producing for a while before decline and stop producing oil and water-cut is almost 100% before the defined end of production life. This depends on both length of secondary flooding and salinity in the tertiary water flooding.

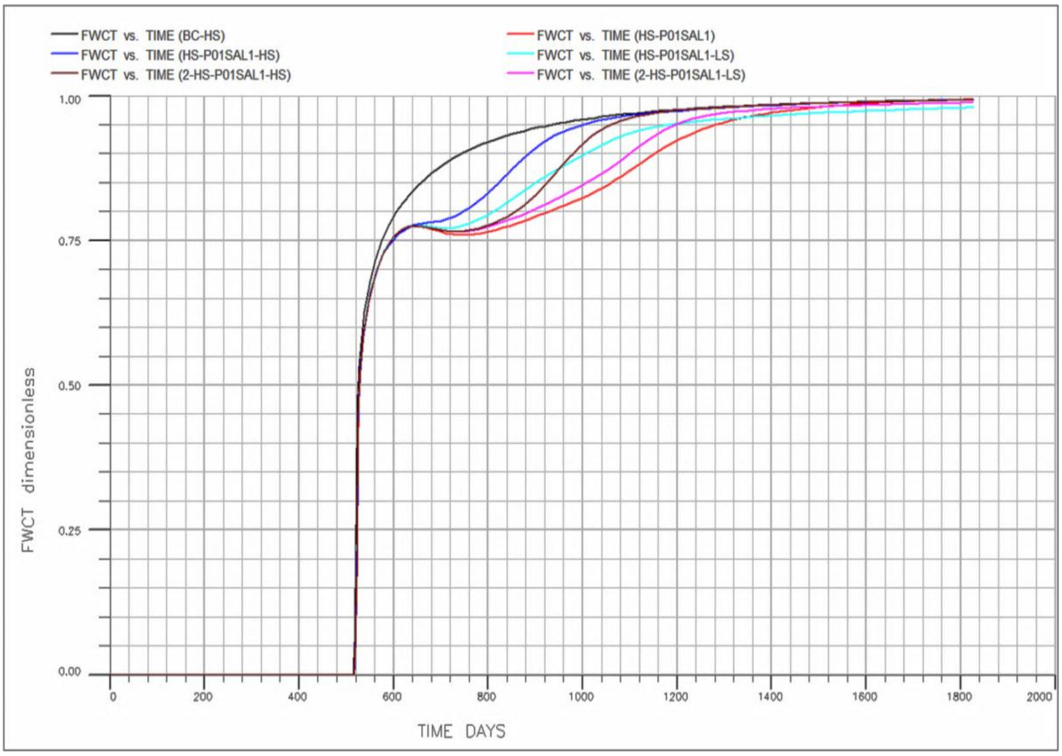


Figure 4. 58 The water-cut profile of tertiary phase study of the combination of low salinity water flooding and polymer flooding

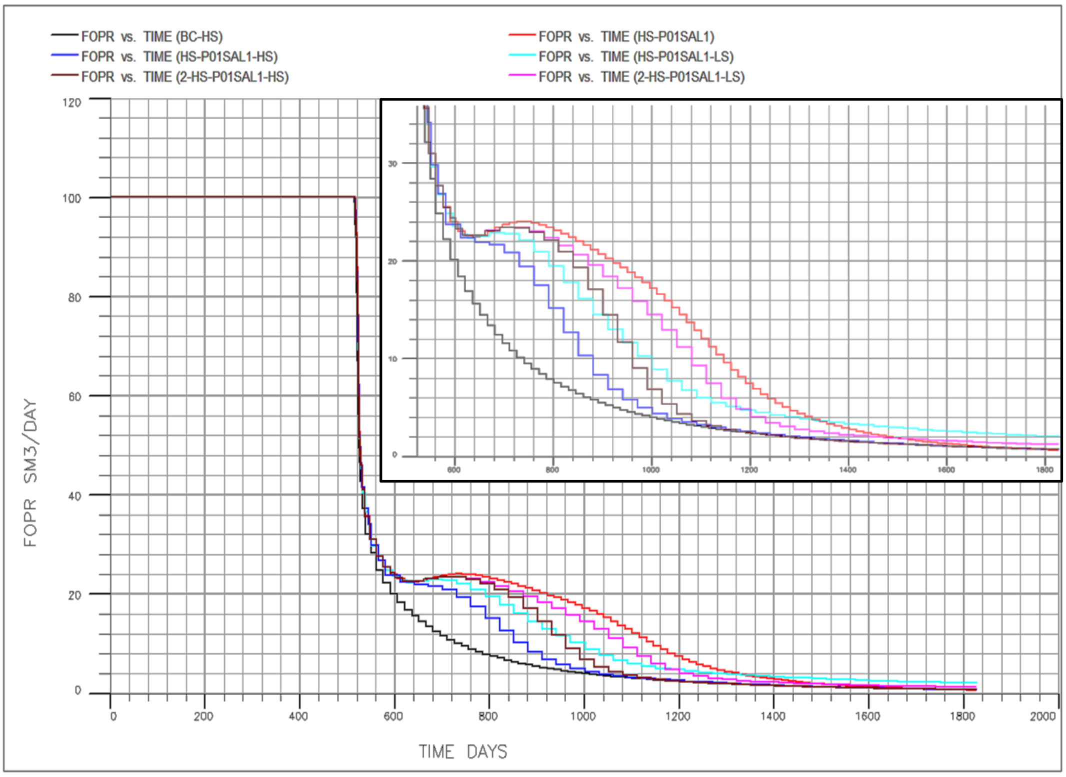


Figure 4. 59 The oil production rate of tertiary phase study of the combination of low salinity water flooding and polymer flooding

4.3.4.1 Effect of range of second recovery phase

The comparison of oil recovery from all cases varied range of secondary recovery phase and salinity of water flooding in tertiary recovery phase is presented in Fig.4.60. Regardless salinity in tertiary water flooding for both HS and LS, the longer range of polymer flooding can create the longer oil production. Although, the continuous polymer flooding causes the highest oil recovery, the oil recovery of cases with LS flooding in tertiary phase are not extremely less but, at the same time, more attractive when considering economics.

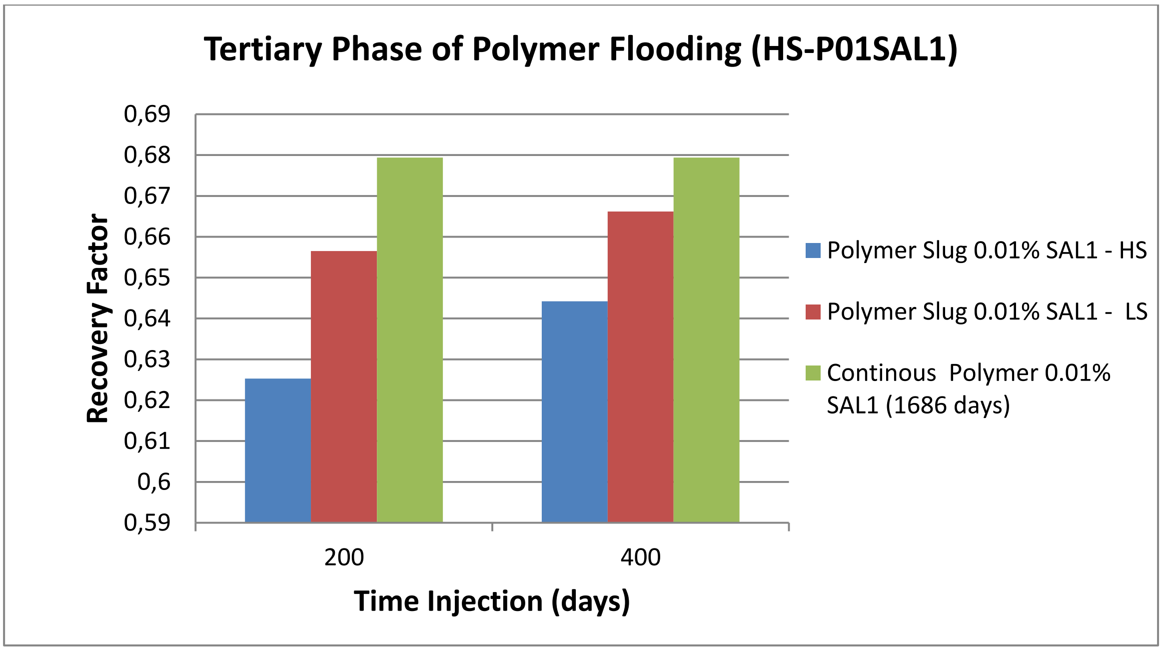


Figure 4. 60 The oil recovery of all cases varied range of secondary recovery phase and salinity of water flooding in tertiary recovery phase (polymer flooding study)

4.3.4.2 Effect of salinity in tertiary recovery phase

From Fig.4.60, It can be demonstrated that with the same polymer injection range, the lower salinity in tertiary water flooding can produce higher oil recovery. Moreover, it is interesting to see that the case with 200 polymer injection days with LS following in tertiary phase can affect better oil recovery than the case with 400 injection days followed by HS flooding. This means that apart from having a function as driving polymer solution through the reservoir, water flooding can still change wettability of the system to become more water-wet by using LS instead of HS flooding, thus it results to higher oil recovery. In another meaning, varying salinity in tertiary water flooding influence to oil production more than increasing range of polymer flooding.

Nevertheless, from oil production profile in Fig., it is noticed that polymer flooding impact to the system in a very short period. We propose one more reason is because the polymer concentration used in the test is a little too low. So, we did more tests with the same range of polymer injection but with higher polymer concentration. By avoiding the too high field pressure problem, polymer concentration 0.03%wt with 1000 ppm salinity is selected to use in this special case study because the result from section 4.2.4 shows that the continuous polymer flooding with this concentration can gives oil recovery as same as using polymer 0.1%wt concentration but does not cause high field pressure problem . According to the previous discussion, using HS flooding in the tertiary phase does not give a good result; this case is focus only using LS in tertiary water flooding to compare with the best case from the previous study of tertiary recovery phase of polymer flooding.

Fig.4.61 displays the comparison of oil recovery results. It can be seen that comparing at the same condition: range of polymer injection and salinity in the tertiary phase, polymer concentration 0.3%wt give much higher oil recovery, particularly, all cases with tertiary flooding have better recovery than the best tertiary flooding case from 0.01%wt polymer concentration. The 400 polymer injection days of 0.03%wt also affects to oil recovery close to continuous polymer flooding result more than the cases with concentration 0.01%wt.

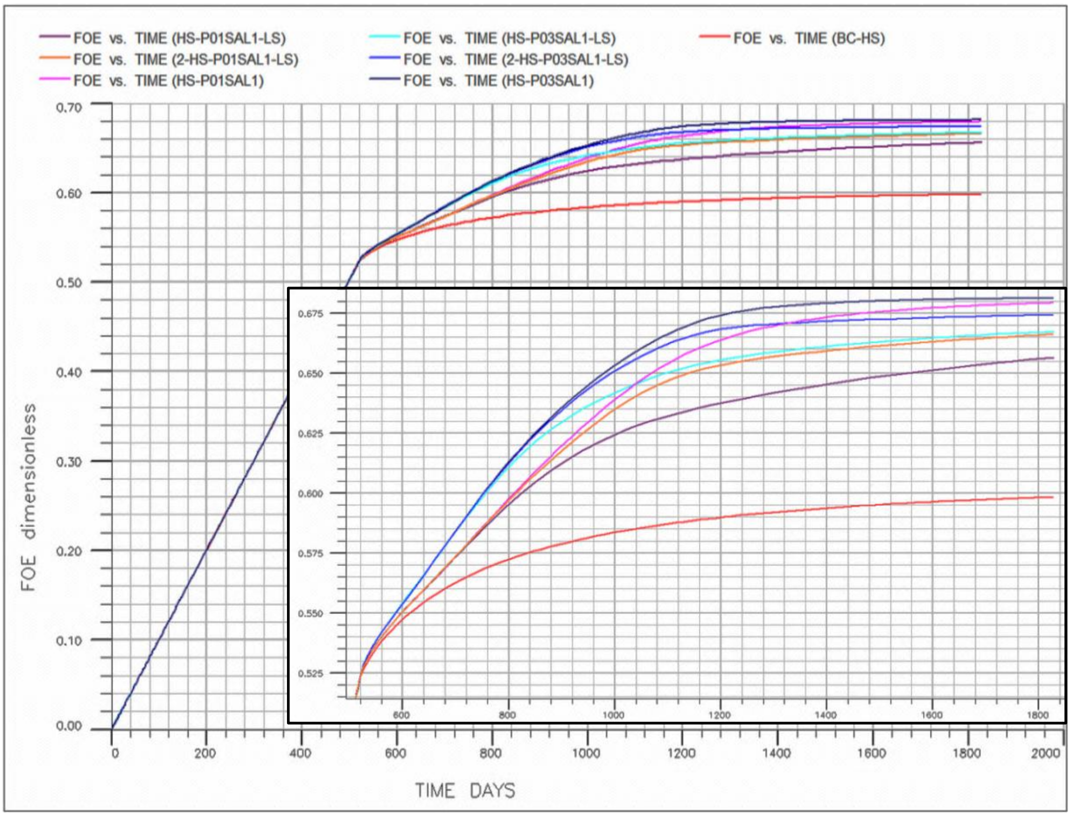


Figure 4. 61 The oil recovery of tertiary phase study comparing polymer concentration

Fig.4.62 and Fig.4.63 present the oil production rate and water-cut profile result. The figures explain how the higher oil recovery comes from. It can be illustrated that the higher polymer concentration results to higher oil production at the beginning after water breakthrough due to increasing oil viscosity. Moreover, it is noticed that oil production rate fall down almost at the same time between two polymer concentrations. Although the 0.03%wt continuous polymer flooding drops slightly faster than 0.01%wt case, the higher oil rate at the beginning can still impact to higher overall recovery. According to oil production rate profile, water-cut of the high polymer concentration is also better than the low polymer concentration.

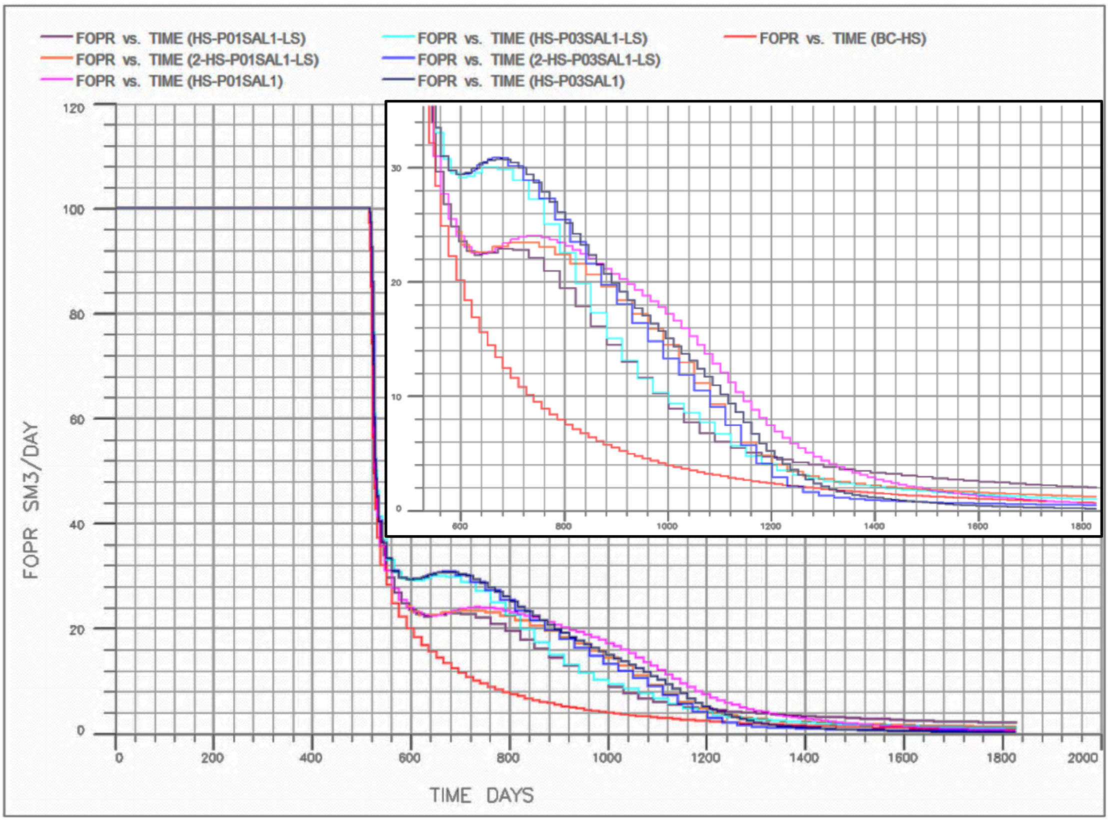


Figure 4. 62 The oil production rate profile of tertiary phase study comparing polymer concentration

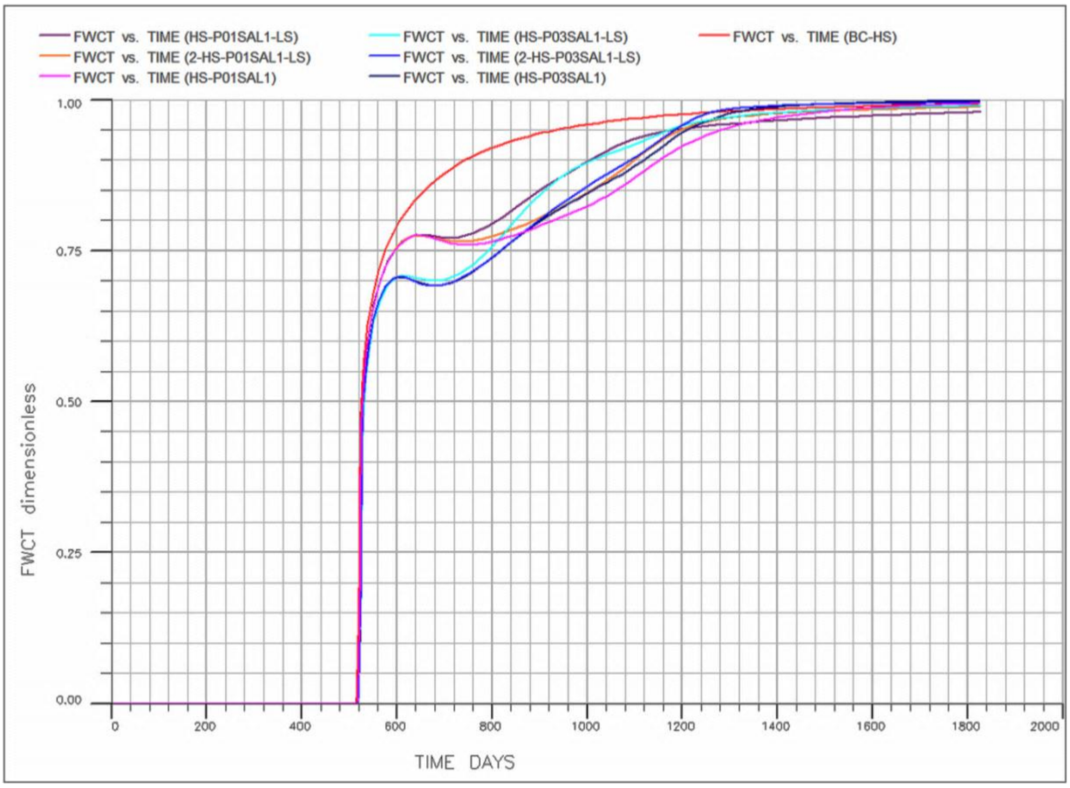


Figure 4. 63 The water-cut profile of tertiary phase study comparing polymer concentration

The comparison of oil recovery from all cases varied range of secondary recovery phase: 200, 400 and 1686 (continuous flooding) days, and varied polymer concentration: 0.01%wt and 0.03%wt, are presented in Fig.4.64. It is noted that all case started with HS flooding for 200 days and using LS flooding in tertiary phase after polymer flooding range.

As describing above, the cases 0.03%wt produce better oil recovery in all aspects and its continuous polymer flooding even gives the same oil recovery compared to using continuous polymer concentration 0.1%wt. Although the polymer slug cases of polymer 0.03%wt cannot reach the same or the better oil recovery to the continuous flooding case, they give higher recovery than using polymer 0.01%wt concentration.

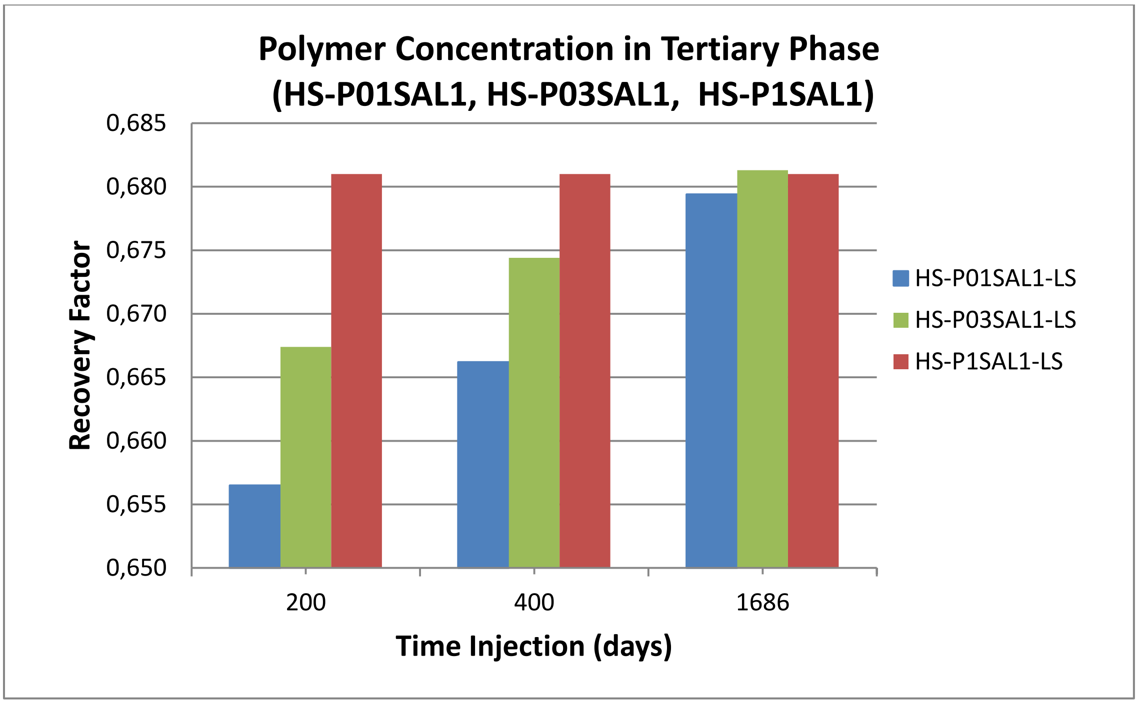


Figure 4. 64 The oil recovery of all cases of tertiary phase study comparing polymer concentration

4.3.4.3 Summary

This section has presented that both injection ranges of secondary flooding and salinity in the tertiary water flooding influence to the study of combination of low salinity and polymer flooding. In order to get higher oil recovery, the longer polymer injection range and the lower salinity in tertiary water flooding are two main factors. The viscous polymer solution can impact longer with the increasing polymer injection range. The LS flooding can improve more favorable wettability of the system after polymer flooding and also be the driving fluid for polymer solution. Moreover, the salinity in tertiary water flooding influence to the result more powerful than the range of polymer injection. Therefore, the best case should be using polymer 0.03%wt concentration with 1000 ppm salinity solution in the secondary phase and followed by LS flooding in the tertiary recovery phase that gives 8.6% incremental cumulative oil recovery to the HS base case.

Chapter 5

Overall Discussion

In low salinity water flooding (LS), the wettability changing from oil-wet to more water-wet has been observed as a major reason in enhancing oil recovery. This is due to the relative permeability relation changing in the input data as a function of salinity in the water injection. Decreasing brine salinity can cause more oil production but strongly affect in the salinity threshold range between 1,000 ppm- 5,000 ppm. Therefore, in this study, salinity 40000 ppm is represented high salinity brine, while 1000 ppm is represented low salinity brine. The first low salinity water injection from the first production day continues to the end of production life can improve additional oil recovery 6.1% from the reference case that is continuous high salinity water flooding (HS). Regarding LS as secondary recovery, as the earlier starting continuous flooding, the higher oil recovery. After HS flooding 200 days, the continuous LS flooding results 5.5% compared to reference case.

From the combination of LS and alkaline flooding, based on alkaline properties used in this study, the oil recovery increase as alkaline concentration increase while salinity in alkaline solution decrease. This is an effect of IFT reduction in the system. However, the alkaline concentration at 1.5%wt is not high enough to influence the recovery; thus alkaline concentration at 3%wt is needed. The high-/low salinity in the first phase still act as changing the wettability become more favorable water-wet, but it does not give the important different on recovery as all cases are stronger affected from the alkaline concentration changing than the salinity in the first phase.

In the combination of LS and surfactant flooding, based on surfactant properties used in this study, increase of surfactant concentration can improve oil recovery because of IFT reduction but the surfactant concentration 2%wt is too much, since the oil recovery is almost the same to the case with concentration 1%wt. Lowering salinity in surfactant solution can also affects producing more oil and salinity 1000 ppm is supposed to be either optimum salinity or type II(-) in this system. The low salinity in the first phase gives a better recovery than high salinity but still not significantly better. As surfactant concentration 2%wt is too high, resulting effect of salinity in surfactant solution is stronger than effect of surfactant itself and effect of wettability changing in primary recovery phase.

From combination of LS and polymer flooding, based on polymer properties used in this study, increasing polymer concentration can influence higher oil recovery due to increasing viscosity in water flooding, resulting the improvement of sweep efficiency.

The lower salinity in the first phase still can change the system become more water-wet, while lower salinity in the polymer solution can cause even higher viscosity polymer solution. The high salinity in polymer solution makes the polymer flooding results almost the same to formation water flooding because the viscosity of high salinity in polymer solution is similar to formation water flooding; thus it does not help the sweep efficiency at all. However, the low salinity in polymer solution can cause too high viscosity, particularly with also high polymer concentration, so that it moves difficultly and block the flow path, resulting decrease of permeability in the reservoir as it can be observed that field pressure increase a lot and this cannot apply to the reality because it can fracture the reservoir. Therefore, the optimization is needed to find the suitable condition of salinity and polymer concentration used in polymer flooding.

In the combination of low salinity and AP flooding, alkaline impacts significantly in decreasing the polymer adsorption on the rock surface. Moreover, as there is no high field pressure problem when alkaline concentration is high enough, even in the same polymer concentration and salinity as the combination of low salinity and polymer alone flooding; thus, IFT caused by alkaline can drives the AP solution move easier through the system. The polymer major effect is increasing the viscosity of AP solution, results to higher sweep efficiency and oil recovery. The salinity in AP solution also plays an important role to both alkaline and polymer as low salinity in AP solution increase higher oil recovery in all aspects. The alkaline in AP solution still need to be in optimum condition and optimum salinity condition to get the lowest IFT. There is no evidence that low salinity in this case has reached the optimum salinity condition, however, the low salinity in AP solution results to additional recovery compared to high salinity. So that, it can be assumed that low salinity is in either under-optimum or optimum condition that is the preferable state. The low salinity in AP solution also increases AP solution viscosity much higher than high salinity. Therefore, the higher concentration of both alkaline and polymer with lower salinity are preferable to improve oil recover. However, due to the side effect such as high field pressure, the optimization of these three parameters is important.

In the combination of low salinity and AS flooding, Even though it is observed that alkaline concentration at 1.5%wt is too low, the surfactant adsorption on the rock surface still becomes less due to the alkaline effect. The higher alkaline concentration influences absolutely to even lower IFT and surfactant adsorption. Surfactant still acts as reducing IFT and when combining with alkaline effect, it results to reach the ultralow IFT. Moreover, surfactant in AS solution can extend the period of low dynamic IFT due to increase interfacial resistance to mass transfer. However, surfactant concentration 2%wt is too high that is considered as above the CMC value; thus it does not give much different in result compared to the lower surfactant concentration. The salinity is concerned to be in the optimum salinity condition that impact to the lowest IFT. In order to achieve the major effect of combination of AS, which is ultralow IFT condition, the optimum alkaline and optimum surfactant concentration with optimum salinity is preferable that is high alkaline concentration and low surfactant concentration in, low salinity in this study.

In the combination of low salinity and SP flooding, the surfactant main effect is reducing IFT and the polymer main effect is improving sweep efficiency. Since the low salinity and high polymer concentration causes too high viscosity that move difficultly and block the permeability in the reservoir problem, however, in combination with surfactant, surfactant also acts as reducing polymer viscosity; thus the SP solution flow easier but still more viscous than surfactant alone, resulting in improve the sweep efficiency. Surfactant concentration 2%wt is still too high, and then does not affect much differently from surfactant 1%wt concentration. On the other hand, polymer increases IFT of the surfactant solution because of interaction of the functional group of both polymer and ionic surfactant. But due to the strong effect of surfactant, so that polymer does not influence much on IFT. Therefore, the optimum surfactant concentration is considered importantly. The polymer concentration is needed to be aware of too high viscosity and results to high field pressure. Low salinity is still preferable in all aspects in order to attain the optimum salinity condition in surfactant and increase polymer viscosity. In this test, the low surfactant and the high polymer concentration in low salinity is preferable.

In term of tertiary phase water flooding following low salinity water flooding in the secondary phase, the longer of secondary injection causes the higher recovery. However, there is a certain injection range that there is no longer effect of low salinity in wettability changing; thus, the low salinity injection is inefficient and better to change to tertiary high salinity water flooding. In case of tertiary water flooding flowing the chemical flooding in the secondary phase, both injection ranges of secondary phase and salinity in the tertiary water flooding is important. For alkaline flooding, there is a delay of alkaline effect in the system that caused by trapped in-situ surfactant. The low salinity flood can remove the trapped in-situ surfactant and also change the system become more water-wet. Low salinity in tertiary water flooding influences the recovery more than the secondary injection range; thus the middle case, which is 800 days of the mixed low salinity in high alkaline solution, followed by low salinity water flooding enhances highest oil recovery. For surfactant flooding, the main issue is optimum surfactant concentration and optimum salinity, hence; optimization of these two factors is very important. So that, the range 600 days of mixed low salinity in low surfactant solution, also followed by low salinity water flooding is the preferable solution. In case of polymer flooding, the viscous polymer solution can impact longer with the increasing polymer injection range. At the same time, the LS flooding can improve more favorable wettability of the system after polymer flooding and also be the driving fluid for polymer solution. The low salinity in tertiary water flooding, still, influence to the result more powerful than the range of polymer injection. Therefore, the optimal case is by using middle polymer concentration mixed with low salinity for 400 days and followed by low salinity water flooding.

Chapter 6

Conclusions and Recommendations

In this study, the models of low salinity water flooding and the combination of low salinity water and alkaline flooding, surfactant flooding, polymer flooding and ASP flooding have been simulated by using Eclipse 100 (2009.1) simulator in order to study the effect of the combination of low salinity and each chemical flooding type.

On the basis of the simulation results, the following conclusions have been achieved.

1. The wettability modification from oil-wet to water-wet plays a significant role to increase oil recovery from low salinity water flooding. The threshold of salinity between 1000 ppm – 5000 ppm gives strongly effect compared to the sea water with 40000 ppm salinity. Applying the continuous low salinity water flooding in the secondary phase after high water flooding in the first phase can improve higher oil recovery compared to only high water flooding, while little less than only low salinity water flooding. However, at a certain injection range of secondary low salinity flooding, there is no longer effect of wettability changing, leave only pressure maintaining. Therefore, it is better to change to tertiary high salinity water flooding.

2. In all single chemical flooding type as secondary recovery phase, the effect from low salinity water flooding in the phase is seemed to be small. The high-/low salinity in the first water flooding still act as changing the wettability become more favorable water-wet but do not give much different compared to overall recovery.

3. Each chemical flooding type performs its effect well in the simulation. For alkaline flooding and surfactant flooding influence generally in reduction of IFT between oil and water, while polymer flooding increases displacing fluid viscosity and results to increase sweep efficiency. The effects of ASP mainly come from individual chemical effects. However, alkaline does not strongly affect to polymer directly, while it can combined with surfactant to establish the ultralow IFT condition that can reduce amount of surfactant required to reach the same performance. Between polymer and surfactant, polymer increases IFT of surfactant solution, whereas surfactant decreases viscosity of polymer concentration. The combined effect in ASP should be balanced with the single chemical flooding effect as reducing IFT by alkaline flooding and surfactant flooding and increasing sweep efficiency by polymer flooding. Mostly the oil

recovery increases as a function of chemical concentration. In case of, alkaline and surfactant flooding, they need the optimum concentration that gives highest efficiency. In polymer flooding, too high concentration causes high viscosity and can block the permeability in the formation.

4. The low salinity in chemical solution that used as secondary phase recovery influences a positive effect to oil recovery in every case, although it gives different impacts to each type of chemical flooding. Mainly, low salinity increases polymer solution viscosity that can improve sweep efficiency of polymer flooding. The salinity in polymer is also needed to consider with polymer concentration in order to prevent too high viscose solution problem. In alkaline flooding and surfactant flooding, the salinity is need to be optimized to optimum salinity condition corresponding to optimum alkaline concentration and surfactant concentration, where creates the lowest IFT.

5. In term of tertiary water flooding considering the range of combination of low salinity and chemical flooding in secondary phase recovery, the range where makes the alkaline and surfactant flooding reach the optimum concentration is preferable. In case of polymer, the viscous polymer solution can impact longer as the polymer injection range.

6. The low salinity in tertiary water flooding influences better than high salinity water flooding in all combination of chemical flooding in the secondary phase. Apart from wettability changing effect, it can be driving fluid and remove trapped surfactant and polymer left in the formation. The optimum salinity condition is still important to alkaline and surfactant flooding system.

From this study, low salinity water flooding gives a positive effect to overall result when combined with chemical flooding. However, some recommendations are made to continue in further study.

1. Since there is too high field pressure in Polymer flooding part since the reservoir volume has been control, the control mode should be changed to pressure control in polymer part.

2. Due to ASP gives quite high recovery, it is interesting to study the tertiary phase of low salinity flooding after the ASP flooding. We proposed that the low salinity water flooding in the tertiary phase should give similar or even more recovery.

3. The Economics analysis should be performed in order to get the best case with economics consideration.

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Appendix

The reference case data file

```
RUNSPEC
===============================================================
TITLE
LOW SALINITY - ASP INJECTION /

DIMENS
   50   50    6  /

OIL
WATER
POLYMER
SURFACT
ALKALINE
BRINE
LOWSALT
-- automatically turns on Brine option


METRIC

TABDIMS
-- num num  max  max      max     max
-- sat pvt  sat  press    fip     Rs
-- tab tab nodes nodes   regions nodes
    3    1   50   20       2      20 /

WELLDIMS
-- max    max max    max
-- wells conn groups wells/gr
    5        10      1        5 /

START
   1 'JAN' 2012  /

UNIFIN
UNIFOUT

NSTACK
  50 /

--NOSIM
```

```
GRID
================================================================

INIT
DX
  15000*3   /
DY
  15000*3   /
DZ
  15000*3   /

NOECHO
INCLUDE
'./INCLUDE/permx15000.dat' /

INCLUDE
'./INCLUDE/permy15000.dat' /

INCLUDE
'./INCLUDE/permz15000.dat' /

INCLUDE
'./INCLUDE/poro15000.dat' /

TOPS
 2500*2600 /

ECHO

PROPS
================================================================
-- connate water is 40,000 PPM = 40 kg/m3

LSALTFNC
-- F1 = 0 for high salinity
-- F1 = 1 for low salinity
--Salt          F1
--conc         factor
--conc         F1            F2
--kg/sm3       factor        factor
    0.0        1.0           1*
    0.01       0.9           1*
    0.1        0.8           1*
    1          0.7           1*
    5          0.3           1*
    10         0.2           1*
    20         0.1           1*
    40         0.0           1*  /
/
/
```

```
--  High salinity relative permeability curves as function of water saturation

SWOF
--     SWAT        KRW         KROW               PCOW

         0.12          0            1             0
         0.1625        0            0.825         0
         0.2           0            0.68          0
         0.25          0            0.52          0
         0.3           0.0001       0.37          0
         0.325         0.001        0.31          0
         0.375         0.005        0.2           0
         0.4           0.01         0.15          0
         0.43          0.02         0.11          0
         0.5           0.04         0.055         0
         0.55          0.06         0.035         0
         0.6           0.08         0.02          0
         0.65          0.11         0             0
         0.675         0.125        0             0
         0.7           0.14         0             0
         0.75          0.19         0             0
         0.8           0.35         0             0
         0.85          0.51         0             0
         0.9           0.68         0             0
         0.95          0.84         0             0
         1             1            0             0       /

--  Low salinity curves  relative permeability curves as function of water saturation
--     SWAT        KRW         KROW               PCOW
         0.12          0            1             0
         0.1625        0            0.85          0
         0.2           0            0.71          0
         0.25          0            0.56          0
         0.3           0            0.42          0
         0.325         0            0.36          0
         0.375         0.0001       0.24          0
         0.4           0.001        0.19          0
         0.43          0.007        0.14          0
         0.5           0.025        0.08          0
         0.55          0.04         0.055         0
         0.6           0.055        0.035         0
         0.65          0.075        0.015         0
         0.675         0.09         0.01          0
         0.7           0.1          0.001         0
         0.75          0.135        0             0
         0.8           0.19         0             0
         0.85          0.375        0             0
         0.9           0.6          0             0
         0.95          0.8          0             0
         1             1            0             0   /
```

```
-- Table-2 Misible Curves – SURFNUM
--      SWAT        KRW               KROW        PCOW
          0.0             0.0              1.0              0.0
          0.95            0.95              0.0             0.0
          1.0             1.0              0.0              0.0  /

PVTW
-- Ref P    FVF       Water Compress      Water Vis  Viscosibility
   270.0    1.0          4.6E-05                 0.5        0.0 /
-- basic connate water viscosity is 0.5 cP

PVDO
  200             1.0              2
  280             0.999            2
  300             0.998            2
/

ROCK
 270.0  .3E-5 /

DENSITY
-- o      w        g
 850.   1000.   1.2 /

------------------------------------------------------------

--Alkaline keywords

ALSURFST
--Water/oil surface tension multipliers as a function of alkaline concentration
--Alkaline              Water/oil Surface
--concentration           Tension Multiplier
--kg/m3
   0.0                   1.0
   6.0                   0.5
  15.0                    0.3
  20.0                    0.1
  30.0                    0.0 /


ALPOLADS
--Polymer adsorption multipliers as a function of alkaline concentration
--Alkaline multipliers for polymer adsorption
--Alkaline conc.          Polymer Adsorption
--Kg/m3                  Multiplier
  0.0                     1.0
  3.0                     0.7
  6.0                     0.5
  9.0                     0.3 /
```

```
ALSURFAD
--Alkaline multipliers for surfactant adsorption
--Alkaline             Adsorption
--concentration        Multiplier
--Kg/m3
   0.0                 1.0
   3.0                 0.7
   6.0                 0.5
   9.0                 0.0 /
/
/

ALKADS
--Alkaline adsorption
--Alkaline             Alkaline Adsorbed
--concentration        on rock
--Kg/m3 (kg/kg)
   0.0                 0.000000
   3.0                 0.000005
   6.0                 0.000007
   9.0                 0.000008
  10.0                 0.000009 /
/
/

ALKROCK
-- No desorption
   2 /
/
/

----------------------------------------------------------
-- POLYMER KEYWORDS

SALTNODE
0.0
0.01
0.1
1
5
10
20
40
/
```

```
PLYVISCS
-- Polymer solution Viscosity Function
-- Ply conc.    Wat. Visc. mult.
-- kg/m3
0.0             1.0
                1.0
                1.0
                1.0
                1.0
                1.0
                1.0
                1.0  /

1.0             119
                116
                92
                49
                15
                11
                8
                6  /

2.0             147
                140
                121
                67
                26
                18
                12
                9  /
/

-- Polymer Adsorption Function
PLYADS
-- Ply conc.                    Ply conc. Adsorbed by rock
-- kg/m3                        kg/kg
0.0                             0.0
1.0                             0.0000017
2.0                             0.0000017 /

0.0                             0.0
1.0                             0.0000017
2.0                             0.0000017 /
/

TLMIXPAR
-- Todd-Long staff Mixing Parameters
1        1* /
```

```
PLYMAX
-- Polymer-Salt concentration for mixing maximum polymer and salt concentration
-- Ply conc.     Salt conc.
-- kg/m3         kg/m3
     2.0         40.0 /


PLYROCK
--Polymer-Rock Properties
--dead pore      residual        resistance      mass            Ads.
-- space         factor          density   I     ndex            adsorption
     0.16        1.0              2650.0         2               0.000017 /
     0.16        1.0              2650.0         2               0.000017 /
     0.16        1.0              2650.0         2               0.000017 /


-----------------------------------------------------------
-- SURFACTANT KEYWORDS --YUGAL S PROPERTIES

SURFVISC
--Surfactant solution viscosity function
--surfactant             water
--concentration          viscosity
--Kg/m3                  Centipoise
   0.0                   0.5
  10.0                   0.540
  20.0                   0.600 /

SURFADS
--Surfactant Adsorption Function by rock
--surfactant             concentration of
--concentration          surfactant adsorbed by the rock
--Kg/m3                  (kg/kg) = kg surf /kg rock
   0.0                   0.00000
   1.0                   0.00017
   5.0                   0.00017
  10.0                   0.00017 /
/
/
```

```
SURFST
--Water/oil surface tension versus surfactant concentration
--surfactant            water-oil
--concentration         surface tension
--kg/m3                 N/m
   0                    30.0E-03
   0.1                  10.0E-03
   0.25                 1.60E-03
   0.5                  0.40E-03
   1.0                  0.07E-03
   3.0                  0.006E-03
   5.0                  0.004E-03
  10.0                  0.006E-03
  20.0                  0.01E-03 /

SURFCAPD
--Surfactant capillary de-saturation functions
--log of the            miscibility
--capillary number      function
--Log10                  0 = immiscible, 1= miscible
  -8                    0.0
  -7                    0.0
  -6                    0.0
  -5.0                  0.0
  -2.5                  1.0
   0                    1.0
   5                    1.0
  10                    1.0/
/
/

SURFROCK
--Specifies the surfactant-rock properties - desorption, mass density rock
--desorption      mass density
--index          of this rock
   2             2650/
/
/

-- Index values:
--If a value of 1 is selected, then the surfactant
--adsorption isotherm is retraced whenever the
--local surfactant concentration in the solution decreases.
--If a value of 2 is selected,
--then no surfactant desorption may occur.

------------------------------------------------------------------
```

```
RPTPROPS
   'PLYVISC'
   'SURFVISC' /

REGIONS
==============================================================
SATNUM
-- immiscible, high salinity = 1
   15000*1 /

FIPNUM
   15000*1 /

MISCNUM
   15000*1 /

SURFNUM
   15000*3 /

LWSLTNUM
-- low salinity curves
   15000*2 /

RPTREGS
 24*0 /

RPTREGS
'SURFNUM' 'LWSLTNUM' 'LSLTWNUM'
'MISCNUM'
/

SOLUTION
==============================================================

EQUIL
-- Datum   Pressure   WOC
2680       270        2680 1*  2000/

SALTVD
-- depth                salt
-- meters               conc
--   m                  kg/m3
   5000.0               40.0
   5500.0               40.0 /

--RPTSOL
--  RESTART=1  FIP=3  /

RPTRST
'BASIC=2'   'VELOCITY' 'RK' 'VISC'
```

```
'FIPSALT'
/

SUMMARY
==========================================================
RUNSUM

-- polymer injection total
-- and FOPT for economics calculation
FOPT
WBHP
/
WOPR
/
WOPT
/
WLPR
/
WWPR
/
WWPT
/
WWCT
/
WWIR
/
WWIT
/
TIMESTEP
DATE
FWIR
FOPR
FOPT
FPR
FOPV
FWIT
FOE
FWCT
TCPU

--SALT
FSPR
FSPT
FSIR
FSIT
FSIP
FSPC
FSIC
WSPR
/
```

```
WSPT
/
WSIR
/
WSIT
/
--POLYMER
FCIT
FCIR
FCPR
FCPT
FCIP
FCAD
WCPR
/
WCPT
/
WCIR
/
WCIT
/
BCCN
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BCIP
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BCAD
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
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12 12 1 /
14 14 1 /
15 15 1 /
/
BSCN
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BSIP
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BEPVIS
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BEWV_POL
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BEMVIS
 1 1 1 /
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 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BEWV_SAL
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
--SURFACTANT
FTITSUR
FTIRSUR
FTPRSUR
FTPTSUR
FTIPTSUR
FTADSUR
WTPRSUR
/
WTPTSUR
/
WTIRSUR
/
WTITSUR
/
BTCNFSUR
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BTIPTSUR
 1 1 1 /
 1 1 2 /
 4 4 1 /
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 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BTADSUR
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BTCASUR
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
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BEWV_SUR
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
--ALKALINE
FTPTALK
FTPRALK
FTIRALK
FTITALK
FTIPTALK
WTPRALK
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WTPTALK
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WTIRALK
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WTITALK
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BTCNFALK
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BTADSALK
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BTSTMALK
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BTPADALK
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
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BTSADALK
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 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
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BPR
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
 /
BOSAT
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BOVIS
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BWSAT
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
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12 12 1 /
14 14 1 /
15 15 1 /
/
BWVIS
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BOKR
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
BWKR
 1 1 1 /
 1 1 2 /
 4 4 1 /
 5 5 1 /
 7 7 1 /
10 10 1 /
12 12 1 /
14 14 1 /
15 15 1 /
/
RPTSMRY
1 /

ALL
SEPARATE
RUNSUM
MSUMLINS
MSUMNEWT
--RPTONLY
```

```
SCHEDULE
================================================================

RPTSCHED
 'FIP=1' 'WELLS'  'SUMMARY=2'  /

RPTRST
  'BASIC=2'  /

TUNING
  .01   20.  .0001 .0001  /
  /
 20 1*  50    /

MESSAGES
2* 100 5*  100 1* 20 /

-- WELL SPECIFICATION DATA
--
-- WELL         GROUP LOCATION
-- NAME         NAME    I  J    DEPTH
WELSPECS
    OP           G       50 50   2600     'OIL'      3*    'NO'  /
   INJ           G       1    1   2600     'WAT'     3*    'NO'  /
/

COMPDAT
-- COMPLETION SPECIFICATION DATA
--
-- WELL         -LOCATION-                   OPEN/   SAT  CONN    WELL EFF SKIN
-- NAME         I        J        K1       K2      SHUT    TAB  FACT     ID   KH
--   1          2        3         4        5      6           7       8          9
    OP          1*       1*        1       6        'OPEN'    0       0        0.5 /
    INJ         1*       1*       1        6        'OPEN'    0       0        0.5 /
/

WCONPROD
-- PRODUCTION WELL CONTROLS
--
--  WELL       OPEN/          CNTL                   RES
--  NAME       SHUT           MODE                   RATE
     OP        OPEN           RESV           4*       100       0.0 4* /
/

-- INJECTION WELL CONTROLS
WCONINJE
-- Well         inj      current          cntl              Surf      RESV
-- Name         Phase  Status             Mode              rate      rate   p
    INJ         WAT    OPEN              'RESV'            1*        100  /
```

```
--First Phase Injection
-- inject alkaline
WALKALIN
--well    alkaline injection
--name    concentration kg/m3
   INJ        0.0 /
/

-- inject surfactant
WSURFACT
--well    surfactant injection
--name    concentration kg/m3
   INJ           0.0 /
/

-- inject polymer
WPOLYMER
--well    polymer injection                 Salt
--name    concentration kg/m3           concentrations
    INJ       0.0                               40.0 /
 /

TSTEP
 0.01 /

TSTEP
-- 200 days
    6*30            20 /


-- Secondary CONTINOUS INJECTION OF ASP
-- inject alkai + polymer + surfactant
--
-- inject alkaline
WALKALIN
--well    alkaline injection
--name    concentration kg/m3
   INJ         0.0 /
/
-- inject surfactant
WSURFACT
--well    surfactant injection
--name    concentration kg/m3
   INJ           0.0 /
/
-- inject polymer
WPOLYMER
--well             polymer injection                  Salt
--name             concentration kg/m3      concentrations
    INJ              0.0                              40.0 /
```

```
TSTEP
  1.  /

TSTEP
-- The rest of production life until 5 years
  54*30   5 /

END
```