NUMERICAL SIMULATION OF ENHANCED OIL RECOVERY USING A GUM ARABIC POLYMER

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By

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CERTIFICATION

This is to certify that the thesis titled “Numerical Simulation of Enhanced Oil Recovery Using a Gum Arabic Polymer” submitted to the School of Postgraduate Studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree, is a record of original research carried out by Akpan Emmanuel Akaninyene in the Department of Petroleum Engineering.

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ABSTRACT

Oil reserves are now located in hard-to-reach locations. This, combined with low oil prices, makes drilling for new reserves very expensive and risky. Enhanced oil recovery, which increases the amount of oil that can be recovered from a reservoir, should therefore be considered. This work uses numerical simulation to determine the suitability of gum arabic as a polymer for EOR operations. This was done by matching core-flooding experiments using Eclipse. Simulation gave a waterflooding oil recovery match of 53 % compared to the experimental recovery of 55 % while alkali-surfactant-polymer flooding gave an oil recovery match of 80.53 % compared to the experimental recovery of 82 %. Extrapolating from core to field simulation, the ASP slug formulated increased total field oil production by increasing recovery from 62.48 %, at the end of the waterflooding, to 85.8 %. This demonstrates the potential of gum arabic for EOR operations.

Keywords: enhanced oil recovery, numerical simulation, core-flooding experiments, waterflooding oil recovery, alkali-surfactant-polymer flooding, gum arabic for EOR operations

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DEDICATION

To God, and my family (The Akpans)

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CHAPTER ONE: OVERVIEW

1.1 INTRODUCTION

The average recovery factor using conventional primary and secondary production techniques to the economic limit is about 33 % (Gabriel, 1979; Wardlaw, 1996). This implies that more than 60 % of oil is not recovered either because it is bypassed by the injected water, or it is too viscous to be displaced by the water. Kevin and Raymond (1999) noted that recovery depended on a number of factors that include: the nature of crude oil, reservoir properties, existing technology and the prevailing economic climate. Water injection resuscitates the pressure of a depleted reservoir and displaces the oil.

However, due to its high mobility, water (which is less viscous than oil) tends to evade large volumes of the oil and breaks through to the producing well before adequately sweeping the reservoir (Green & Willhite, 1998). This challenging characteristic of waterflooding eventually results in only part of the reservoir being exposed to the water for a realistic amount of time and to the injection scheme. In addition, reservoir heterogeneity aggravates the injected water's tendency to mobilize only the oil in regions with high permeability, which leads to an early breakthrough in that region (Green & Willhite, 1998).

The mobility ratio is the ratio of the displacing fluid's mobility to that of the displaced fluid. When the mobility ratio is greater than one, the displacement is unfavourable. The required reduction in the mobility of the injected phase can be achieved by viscosifying the injected phase. Viscous fingering and frontal instabilities, which are undesirable, can be dampened by adding a polymer at the injected phase (Green & Willhite, 1998).

Over the years, flooding has been carried out in various forms; alkaline-surfactant (AS) flooding, surfactant-polymer (SP) flooding, alkaline-polymer (AP) flooding and alkaline-surfactant-polymer (ASP) flooding. Conventionally alkaline-surfactant-polymer flooding has been carried out using polymers like xanthan gum and partially hydrolysed polyacrylamide, which are not readily available in Nigeria.

The polymer used in this study is gum arabic because it is a polysaccharide and has a similar molecular structure to xanthan gum and it is commercially available in Nigeria.

There is plenty of research on alkaline-surfactant-polymer flooding using xanthan gum and other polymers, but very little ASP flooding using gum arabic. The purpose of studying these fluids is to develop an understanding of their intricate behaviours, which then can be applied in the field.

1.2 BACKGROUND TO THE STUDY

Chemical flooding methods are considered to be a special branch of enhanced oil recovery (EOR) processes to extract the oil that remains after waterflooding (Dong, Ma & Liu, 2009; Jamaloei, Asghari & Kharrat, 2012; Pei, Zhang, Ge, Tang & Zheng, 2012). The performance of these chemicals, however, varies depending on the particular reservoir's oil and rock properties. Therefore, laboratory core-flooding experiments are required in order to evaluate the performance of various chemicals and their impact on the properties of the reservoir rock and crude oil (Ansarizadeh, Mary & Strong, 2012). As all field operations are ultimately studied through simulation models in some form, it is important that the simulation technology is on a par with all relevant experimental findings. The objective of this particular work is to see if a realistic model, which simulates these experimental results, can be developed using a commercial simulator. This work also will discuss the laboratory and facility design required for implementing an ASP project.

1.3 AIMS AND OBJECTIVES

The aim of this research is to determine the suitability of gum arabic as a polymer for EOR operations using numerical simulation. The objectives of this study are:

- History matching of the simulation model to core flooding;
- Investigate effects of polymer concentration on oil recovery;
- Run a sensitivity study on slug parameters to study performance;
- ASP slug extrapolated and performance tested for a synthetic reservoir.

1.4 PROBLEM STATEMENT

Oil production from the primary and secondary recovery may result in an oil recovery between 20 % and 40 % of the original oil in place (OOIP), depending on the above-mentioned parameters. This leaves more than 60 % of the original oil in place (OOIP) to be recovered by tertiary recovery processes like alkaline-surfactant-polymer flooding. However, if the mechanisms of ASP are not fully understood, it would be difficult to optimize an ASP mixture or system. Very few authors have used gum arabic as a polymer for flooding, so there are very few works with which to compare results, hence, there is some degree of uncertainty in the prediction of results using gum arabic as a polymer.

The flow of ASP solutions in porous media is very complex. This complexity and the uncertainty of the reservoir characterization make the design and implementation of robust and effective ASP flooding to be quite challenging. Poorly designed and implemented ASP flooding may even cause a reduction in oil production. Therefore, accurate numerical simulation prior to the field flooding is essential to a successful design and to the field implementation.

Core analysis is fundamental to understanding the mechanisms. Properties derived from core analysis are extrapolated to reservoir scale, on the assumption that cores are homogenous. In reality, cores are heterogeneous at a micro level. This leads to an approximation of properties, thus leading to higher uncertainty.

1.5 JUSTIFICATION FOR THE STUDY

Description of a chemical process requires many parameters. Ideally, these parameters need to be measured in the laboratory. However, it is not always practical to measure all of these parameters, because of the limited time, high cost, and/or lack of laboratory equipment.

Sometimes, some of these parameters are obtained using numerical simulation by adjusting these parameters to history-matched experiments. Therefore, numerical simulation could be very useful.

A critical step to make ASP flooding more effective is to find the optimal values of design variables that will maximize a given performance measure (for example, net present value, and cumulative oil recovery) for a heterogeneous and multiphase petroleum reservoir.

CHAPTER TWO: LITERATURE REVIEW

2.1 INTRODUCTION

Depending on the production life of a reservoir, oil recovery can be divided into three stages: primary, secondary and tertiary (Neil, Chang & Geffen, 1983; Chang et al., 2006). The objective of EOR is to develop the reservoir after primary depletion.

***Primary recovery*:** The primary recovery is the first stage of recovery by natural drive energy initially available in the reservoir without injection of any fluids or heat into the reservoir. Oil is produced from the reservoir by using the natural energy of the trapped fluids in the reservoir. The efficiency of the oil displacement depends mainly on the existing natural pressure in the reservoir. This primary depletion mechanism can be rock and fluid expansion, solution gas, water influx, gas cap, or gravity drainage, or a combination of multiple sources of energy.

Secondary recovery: The second recovery is the injection of external fluids, such as waterflooding and/or gas injection, mainly for the purpose of pressure maintenance and volumetric displacement. When oil production declines because of hydrocarbon production from the formation, the secondary oil recovery process is employed to increase the pressure required to drive the oil to production wells.

Tertiary recovery: In the tertiary recovery, usually chemicals and/or thermal energy are introduced into the reservoir to improve oil recovery by fluid mobilities and/or interfacial tensions to improve flow. The application of EOR methods is meant to improve the sweep efficiency in the reservoir by the use of chemical injectants that help enhance reservoir energy and reduce the remaining oil saturation below the level achieved by conventional injection methods.

2.2 CONCEPTS ON ALKALINE-SURFACTANT-POLYMER FLOODING

Before describing the mechanisms of the ASP process, some principal concepts are discussed below.

2.2.1 Mobility ratio

The mobility ratio is expressed as:

$$MR = \frac{\lambda_{dispacingfluid}}{\lambda_{displacedfluid}} = \frac{K_w}{K_o}\frac{\mu_o}{\mu_w} \qquad (2.1)$$

Where:

K_w & K_o are effective water permeability (mD) and effective oil permeability (mD), respectively;

μ_w & μ_o are viscosities of water and oil, respectively (cp).

If a mobility ratio is greater than one, it is called an unfavourable ratio because the invading fluid will tend to bypass the displaced fluid. It is called favourable if it is less than one and called unit mobility ratio if it is one. An unfavourable mobility ratio could lead to viscous fingering which is a situation where the displacing fluid breaks through the fluid to be displaced in fingers across the reservoir.

2.2.2 Interfacial tension (IFT)

Interfacial tension is a force per unit length parallel to the interface, in other words, perpendicular to the local density or concentration gradient (Miller & Neogi, 1985):

$$\gamma = \frac{F}{L} \qquad (2.2)$$

Where F is the force per unit length and L is the length over which the force acts.

For a bubble:

$$P_i - P_0 = \frac{4T}{r} \qquad (2.3)$$

2.2.3 Wettability

This is the preference of one fluid to spread over or adhere to a solid surface in the presence of other immiscible fluids (Craig, 1971). The wettability of a crude oil-brine-rock system can have a significant impact on flow during oil recovery, and upon the volume and distribution of the residual oil (Morrow, 1991). Wettability depends on the mineral ingredients of the rock, the composition of the oil and water, the initial water saturation, and the temperature.

2.2.4 Capillary pressure

The capillary forces in a petroleum reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the pore size and geometry, and the wetting characteristics of the system. When two immiscible fluids are in contact, a discontinuity in pressure, which depends upon the curvature of the interface separating the fluids, exists between the two fluids. We call this pressure difference the capillary pressure and it is referred to as P_c.

Denoting the pressure in the wetting fluid by P_w and that in the non-wetting fluid by P_o, the capillary pressure can be expressed as:

$$P_c = P_o - P_w \qquad (2.4)$$

Capillary pressure is related to the interfacial tension, wettability and the curvature of boundaries between different homogeneous phases.

2.2.5 Drainage and imbibition

This section deals with the process of forcing a non-wetting phase into a porous rock. Oil migrates into most reservoirs at the non-wetting phase. Therefore, the initial charging of the reservoir is a drainage process.

Imbibition is a fluid-flow process in which the wetting-phase saturation increases and the non-wetting phase saturation decreases.

Imbibition is also defined as the process of increasing wetting-phase saturation into a porous medium. Spontaneous imbibition refers to imbibition with no external pressure driving the phase into the rock. In a water-wet reservoir, during waterflooding, water will spontaneously imbibe into smaller pores to displace oil, but in an oil-wet reservoir, capillary forces inhibit the spontaneous imbibition of water.

2.2.6 Fractional flow

The fractional flow of a fluid (in the presence of another immiscible fluid) is the ratio of its volume produced to the total volume of the two fluids per unit time. In immiscible displacement processes, the mobility ratio does not remain constant; it varies with the saturation of the flowing phase. Assuming that water and oil are flowing simultaneously through a porous medium, the fractional flow equations for water and oil can be written as:

$$f_w = \frac{q_w}{q_T} \tag{2.5}$$

$$f_w = \frac{q_w}{q_o + q_w} \tag{2.6}$$

Combining this with Darcy's equation gives (assuming neglecting gravitation and capillary pressure):

$$f_w = \frac{1}{1 + \frac{k_{ro}\mu_w}{k_{rw}\mu_o}} \tag{2.7}$$

$$f_w = \frac{1}{1 + \frac{1}{M}} \tag{2.8}$$

The ultimate aim of the EOR process is to increase the final oil recovery, which is a combined function of microscopic and macroscopic efficiencies:

$$Oil\ Recovery\ Efficiency\ (E_{ro}) = \frac{cummulative\ oil\ produced}{oil\ originally\ in\ place} \quad (2.9)$$

$$Ero = Volumetric\ Sweep\ Efficiency(E_{vo}) * Displacement\ Efficiency\ (E_D) \quad (2.10)$$

Where:

E_{vo} = macroscopic efficiency factor E_d = microscopic efficiency factor

$$E_d = \frac{Initial\ oil\ saturation\ S_{oi} - Final\ oil\ saturation\ S_{or}}{Initial\ oil\ saturation\ S_{oi}} \quad (2.11)$$

And:

$$Evo = Arial\ Sweep\ Efficiency * Vetical\ sweep\ Efficiency\ (E_D) \quad (2.12)$$

2.3 CHEMICALS USED FOR ASP (EOR) PROCESS

2.3.1 Role of alkali in ASP flooding

The concept of using alkali to increase oil production was introduced by Frederick Squires in 1917 (Squires, 1917). He observed that higher oil recovery could be achieved from oil sands if water was flooded in the presence of alkalis. It was assumed that the alkalis react with organic acids to generate in-situ soap, which decreases the oil-water interfacial tension. Later, Johnson Jr. (1976) summarized the mechanism as follows:

- Emulsification and entrainment;
- Wettability reversal (oil-wet to water-wet state, or vice versa);
- Emulsification and entrapment.

2.3.2 Role of surfactant in ASP flooding

The function of the surfactant in ASP is to reduce the interfacial tension (IFT) between oil and water, as a result, the capillary force is reduced and additional oil can be mobilized. Surfactants are molecules that will naturally tend to accumulate at the interface of oil and water. Normally they have a polar head group and a non-polar tail group, which have different affinities for polar and non-polar solutions.

As the surfactant is the most costly component of the ASP flood, different techniques are used to enhance the effectiveness of surfactants. The most common techniques are the use of pre-flux of AP drive, the use of a co-surfactant and co-solvents, or synergy of alkali-surfactant.

2.3.3 Role of polymer in ASP flooding

The objective of polymer flooding as a mobility control agent is to provide better displacement and volumetric sweep efficiencies during a waterflood (Lake, 1989). The two most commonly used types of polymers are synthetic polymers and biopolymers. Typical synthetic polymers include partially hydrolysed polyacrylamide (HPAM) and its derivatives.

HPAM is a polyelectrolyte with negative charges on the carboxylate groups with an average molecular weight in the range of 1 million to 20 million. To date, HPAM is the most widely used polymer in polymer flooding because of its availability in large quantities, customized properties (molecular weight, hydrolysis degree, etc.) and low manufacturing cost. However, this kind of polymer is susceptible to harsh reservoir conditions such as elevated temperatures, salinity and shear forces, which significantly affect their performance in EOR. A typical biopolymer is xanthan gum, a biologically produced polysaccharide, which is believed to be an alternative to HPAM due to the great tolerance to mechanical shear, temperature and salinity. Moreover, a series of modified copolymers, incorporating a small fraction of hydrophobic monomers into the backbone of poly-acrylamide, have been recently proposed in the market.

The hydrophobic interactions in aqueous solution can enlarge the hydrodynamic size of polymer chains and in turn render the polymer solution superior in viscosity and other related features.

2.4 GUM ARABIC

Gum arabic is defined as “a dried exudation obtained from the stems and branches of *Acacia senegal* [now called *Senegalia senegal*], Willdenow or *Acacia seyal* [now called *Vachellia seyal*] (Fam. Leguminosae)” (FAO, 1998). It is a polysaccharide with similar molecular structure to xanthan gum and is commercially available in Nigeria. It comes from the hardened sap of the *Senegalia senegal* and *Vachellia seyal* trees. Gum arabic, also called char gund, gum acacia, meska or char goond, is a natural gum usually free of colour, odour and taste. Though many believe that the gum is primarily used for chewing, it has many other viable uses.

Gum arabic is a pale white to orange-brown solid, see Figure 2.1, that breaks with a glasslike fracture and has a viscosity of 100 cps at 20 % aqueous solution and 55 % solubility at 25 °C (room temperature). The best grades are in the form of spheroid tears of varying size with a matt surface texture. When ground, the powder is paler than the solid and has a glassy appearance. (JECFA, 1995). Gum arabic is also available commercially in the form of white to yellowish-white flakes (Figure 2.2), granules or powder, roller-dried or spray-dried (JECFA, 1995).

Figure 2.1: Hardened sap of gum arabic

Figure 2.2: Gum arabic powder (ground)

Gum arabic has many non-food uses as well. It is utilized in cosmetics, photography, incense cones, shoe polish, postage stamps, cigarette paper adhesive, pyrotechnic operations, and, importantly for this study, gum arabic is used to control viscosity in polymer flooding. This last property is due to the presence of the hydroxyl group and its hydrophilic nature.

2.5 ALKALINE-SURFACTANT-POLYMER (ASP) FLOODING

Alkaline-surfactant-polymer (ASP) flooding is a process in which an alkali, surfactant and polymer are injected into the same slug. It has been considered the most promising chemical method because of its potential to achieve interfacial tension reduction, wettability alteration and mobility control effectively (Mamudu, Olalekan & Uyi, 2015). Although the method of surfactants and alkaline solution injection which converts naturally occurring naphthenic acids in crude oils to soaps has long been used to increase oil recovery, key concepts, such as the need to achieve ultralow interfacial tensions and the means for doing so using micro emulsions, were not clarified until after a period of intensive research between approximately 1960 and 1985.

Nelson, Lawson, Thigpen and Stegemeier (1984) recognized that, in most cases, the soaps formed by injecting alkali would not be at the optimal condition needed to achieve low tensions. They therefore proposed that a relatively small amount of a suitable surfactant be injected with the alkali so that the surfactant/soap mixture would be

optimal at reservoir conditions. With a polymer added for mobility control, the process would be alkaline-surfactant-polymer (ASP) flooding.

Hawkins, Taylor, Nasr-El-Din and Inst (1994) found that the simultaneous injection of alkali and polymer was more effective than the same chemicals injected sequentially with no contact between alkali and polymer. Tong et al. (1998) found that the main mechanisms of ASP flooding are interface producing, bridging between inner-pore and outer-pore, and oil-water emulsion.

Alkali substances have proven to be an appropriate means to improve the oil recovery from oil-wet reservoirs by reversing the rock wettability to a more favourable condition. Wettability alteration function is predominant at alkali concentrations lower than 1 % by weight, whereas IFT reduction is predominant at higher concentrations than 1 % by weight (Arihara, Yoneyama, Akita & Xiang Guo, 1999).

In 2013, Onuoha and Olafuyi conducted a laboratory study on the use of gum arabic for mobility control. In an ASP flooding that they conducted, the displacement efficiencies of two ASP slugs were compared and calculated to be 90.2 % for a sodium hydroxide (NaOH), lauryl sulphate and gum arabic slug and 77.9 % for a sodium hydroxide, polysorbate 80 and gum arabic slug. Their work was on light oil in a water-wet unconsolidated glass bead core. Many ASP flood laboratory tests and field tests or applications using other polymers such as xanthan, scleroglucan, polyachriamide and other cellulose derivatives have been carried out over the years.

Taiwo, Mamudu and Olafuyi (2016) showed that oil recovery by the imbibition process does not follow a regular pattern. It reveals some complexities in the oil mobilization process and an uneven pattern in the oil recovery due the simulated reservoir heterogeneity. They demonstrated that it is not only the grain size of the reservoir rock but also the arrangement of the grains in the core that affects oil recovery. They showed that waterflooding can recover about 70 % while ASP flooding can recover between 16 to 19 % of the original oil in place from the synthesized heterogeneous beads pack.

Bernheimer core gives the best results for ASP EOR flooding operations. Avwioroko, Taiwo, Mohammed, Dala and Olafuyi (2014) demonstrated that oil recovery increases as the formation becomes more water wet. They showed that the displacement efficiency of waterflooding and ASP flooding are markedly affected by the wettability of the core. Wettability is one of the important factors in determining the oil recovery of water and ASP flooding. Water-wet and oil-wet conditions with ASP flooding enhance high oil recovery.

2.6 PREDICTIVE MODELS FOR CHEMICAL FLOODING PERFORMANCE

Huh, Landis, Mayer, McKinney and Dougherty (1990) used a surfactant process simulator to evaluate the performance of a series of surfactant flood tests carried out at the Loudon field in Illinois. They carried out flooding experiments using Berea and Loudon cores and modelled surfactant and surfactant-polymer floods to evaluate and interpret their performances.

The process model, developed and calibrated with laboratory data, accounts for the detailed phase behaviour of the injected and resident fluid mixtures, relative permeabilities and rheology of the resulting phases, the oil displacement mechanism by low interfacial tension, and the retention of the surfactant and the polymer in the reservoir rock. When the surfactant retention is adjusted from the laboratory to field levels, the process model does a reasonable job of describing the field performance. The pilot tests matched by simulation included a 0.7-ac inverted five spot, a 40-ac pattern comprising nine 2.5-ac normal five spots and an 80-ac pattern with nine 5.0-ac normal five spots. The validity of the process model under field conditions was first tested using a simplified reservoir model – an octant of a confined five-spot pattern. The effects of various process parameters and reservoir stratification on process performance were examined.

For full pilot simulations, reservoir models were prepared from detailed reservoir description data for each pilot. This included analyses of cores from 43 pilot wells, induction logs, pressure falloff tests, and pulse tests.

For the small pilot, only minor corrections to the sand thickness and permeability outside of the pattern area were needed to match the production of oil, surfactant, polymer and nine different tracers. The tracers included one overall and four quadrant tracers for the micro-emulsion bank and four quadrant tracers for the polymer-drive water bank. For the two multi-pattern pilots with larger pattern sizes, reasonable matches were also obtained but required more substantial permeability adjustments overall.

Pandey, Beliveau, Corbishley and Kumar (2008) designed an ASP pilot for the Mangala Field, carrying out both laboratory evaluations and simulation studies. The field is the largest discovered oil field in the Barmer Basin of Rajasthan, India having a STOIIP of over 1 billion barrels in multiple-stacked fluvial clastic reservoirs. It contains medium gravity (20°-28° API), waxy, viscous crude (9-17 cp) in high permeability (1-25 Darcy) clean sandstone reservoirs. They used an advanced compositional simulator STARS^{TM} to model the core floods in an attempt to understand the process mechanisms and to generate chemical flood parameters, which were subsequently used in field-scale modelling of the process.

They performed four linear core floods using different polymers and different ASP formulations in native-state cores. The experiments involved saturating the cores to initial oil saturation, multiple pore volume waterflooding followed by multiple pore volume flooding using 1500 ppm, 1000 ppm and 500 ppm of polymer solutions, initially in normal injection water and later on with an alkali and a surfactant added to it. Each slug injection was done at three different frontal advance rates and each slug was separated from other slugs by an intermediate chase water slug of multiple pore volume. The resistance factor data helped in identifying suitable polymers that injected and flowed smoothly through the Mangala core. Polymers showing a high resistance factor indicated some injectivity problems and were not considered for further evaluation.

A series of radial core floods were performed with a core of 10 cm in diameter and 5 cm thick in order to generate and adjust a chemical model built using Computer Modelling Group's STARS^{TM}. All the radial core floods were history-matched to generate the chemical flood simulation parameters that were subsequently used for the pilot-scale simulations. A core flood match involved matching the waterflood behaviour by adjusting the relative permeability curve, using different relative permeability curves corresponding to different capillary numbers to match the chemical flood performance, matching chemical production by adjusting adsorption values, modelling shear-thinning behaviour to match observed injection pressures, and conducting sensitivities on core heterogeneity to see the impact on modelling parameters.

Al Sofi, Liu and Han (2013) conducted a series of surfactant-polymer core-flooding experiments and then compared the results with simulated results obtained from UTCHEM. Their work focused on constructing an SP simulation model using laboratory data and validating it by matching core-flooding results. A series of SP core-flooding experiments were performed in carbonate cores under reservoir condition while chemical injection was implemented in a tertiary mode with varying slug sizes and concentrations. The core-flooding result showed significant oil-recovery potential for SP formulations under the conditions investigated. The base SP flow resulted in 23.4 % incremental recovery after waterflooding, with the polymer and surfactant contributions being about the same. The results also demonstrated the effects of surfactant slug-size and concentration on the recovery performance.

A general SP simulation model was initiated, in which polymer viscosity dependence on concentration and salinity were established in the laboratory, surfactant-phase behaviour parameters were generated from test-tube results, and oil desaturation was based on additional core flooding. After matching water and polymer flooding results, the surfactant simulation model was fine-tuned through history matching the performance of a series of SP core floods. A subsequent sensitivity analysis established the confidence level of the input parameters. The sensitivity analysis also highlighted the significance of IFT reduction.

Finally, they numerically investigated the optimum chemical formulation. Optimization runs were performed under a fixed chemical consumption condition. In summary, their work provides a predictive SP simulation model that can be used to upscale laboratory results to field-scale predictions.

To enhance oil recovery, Sinha et al. (2015) carried out a numerical simulation of sand-pack flooding with an alkali-surfactant-polymer using an advanced compositional simulator named STARS^{TM} available from the Computer Modelling Group. Different chemical slugs such as alkali, polymer and surfactant were taken and their effects on water cut, oil cut, cumulative recovery and additional recovery were calculated. They used sodium dodecyl sulphate (SDS), sodium hydroxide, partially hydrolysed polyacrylamide (PHPAM) as a surfactant, alkali, and polymer with 98 % purity respectively.

The core holder was tightly packed with uniform sands (60-100 mesh) and saturated with 1.0 wt % brine. They built a model whose geometry size was L = 35 cm and r = 3.5 cm. The grid pattern used was $10*1*1$. The grid size in X direction was fixed at 3.5 cm and the grid thickness was taken as 7 cm. Thus, a Cartesian grid was prepared in all cases. In this grid system, the injection and production wells were located in blocks 1 and 10, respectively.

Sinha et al.'s (2015) work showed that the field surfactant and polymer flooding data agreed with the laboratory data. For alkali flooding, the deviation of comparison is slightly higher than the other two. This is due to the complex mechanism of oil recovery during alkali sand-pack flooding. In the case of ASP slug simulation the level of uncertainty is much higher, as a more complicated mechanism is associated with the oil recovery. Interfacial tension reduction, chemical adsorption, mobility control, wettability alteration and saponification of crude oil in the presence of alkali simultaneously occur during ASP slug flooding.

Therefore, the simulation results show a variation in the data. However, they showed that simulated and experimental results are well matched for EOR by chemical injection.

Schlumberger Eclipse is a commercially available reservoir simulator which has an inbuilt feature for ASP flooding. Table 2.1 summarizes the keywords used in Eclipse for polymer flooding.

Table 2.1: Polymer flooding keywords used in Eclipse

SECTION	KEYWORDS
RUNSPEC	POLYMER
PROPS	PLYADS
	PLYSHEAR
	PLYVISC
	PLYROCK
	PLMIXPAR
	PLYMAX
SCHEDULE	WPOLYMER

The polymer flooding keywords mentioned in the table above must be assigned appropriate values in order to run reservoir simulation for ASP flooding. Polymer adsorbs onto the rocks and gets lost, and hence the adsorption cannot be negligible in this model. Therefore, PLYADS keyword has to be modified to make adsorption reflect what is lost to the formation rocks.

Shear thinning occurs in polymers and there viscosity is reduced, but in fines-assisted waterflooding the velocity change is almost negligible therefore, the PLYSHEAR keyword is assigned a constant value which serves the purpose for this research.

Hussain and Zeinijahromi (2013) conducted some experiments on sandstone core plugs and tabulated the data, which showed that, by the injection of waterfloods of varying salinities, viscosity changed slightly. The PLYVISC keyword is, therefore, assigned values for this purpose. It must be noted, however, that the PLYVISC keyword has a condition that the concentrations and viscosities must increase monotonically down the column, which is obvious in the case of polymer flooding, where the sole purpose is to increase the viscosity of the flood by increasing the polymer concentration in order to induce damage to the formation.

This limitation has been dealt with by making an assumption that by injecting waterfloods of increasing salinity the viscosity of the flood would increase and therefore reduce the oil recovery. This would mean that a low salinity waterflood should decrease the viscosity and consequently increase oil recovery. This assumption is made just to deal with the limitation of the Eclipse keyword.

Inaccessible pore volume (IPV), resistance factor and residual resistance factors are important features of polymer flooding and are catered for in the keyword PLYROCK. A similar approach was used for the keyword PLMIXPAR. The actual values can be assigned by history matching, but the sole purpose here is just to use a polymer-flooding model for fines-assisted waterflooding.

A maximum salinity value has been assigned to the PLYMAX keyword at maximum concentration. It must be noted here that salinity is used in terms of equivalent NaCl concentrations, as there is a limitation in Eclipse for multi-ion models to be used with the POLYMER keyword.

Similarly, due to the limitations of Eclipse in handling salinity with polymer flooding, the BRINE keyword is avoided and the WATER keyword is used. If the BRINE keyword had been used, the keyword PLYVISC should have been replaced with PLYVISCS.

Goudarzi, Delshad and Sepehrnoori (2013) carried out an assessment of several reservoir simulators for modelling chemically enhanced oil recovery processes. Data collected from core floods were used as benchmark tests comparing numerical reservoir simulators with CEOR modelling capabilities such as STARS™ of CMG, ECLIPSE-100 of Schlumberger, REVEAL of Petroleum Experts, and UTCHEM from the University of Texas at Austin. Mechanistic simulations of chemical EOR processes will provide predictive capability and can aid in the optimization of the field injection projects.

They found that different parameters such as polymer concentration, viscosity, adsorption on rock minerals, permeability reduction, inaccessible pore volume, etc., are key parameters for controlling an efficient polymer flood. The polymer viscosity in ECLIPSE (ECLIPSE Technical Manual, 2009) is modelled using an effective polymer viscosity $\mu_{p,eff}$ based on the Todd-Longstaff model. The model includes both the effect of dispersion and fingering:

$$\mu_{p,eff} = \mu_m\left(C_p\right)^w . \mu_p{}^{1-w} \qquad (2.13)$$

Where $\mu_m\left(C_p\right)^w$ is polymer solution viscosity as an increasing function of polymer concentration, C_p, μ_p is polymer viscosity at maximum polymer concentration (i.e. injected polymer viscosity) as an input parameter and ω is the Todd-Longstaff mixing input parameter. The model, however, lacks the effect of salinity and hardness on polymer viscosity. That is why the effect of salinity and hardness on viscosity cannot be modelled with Eclipse.

Polymer adsorption in ECLIPSE is calculated using modified Langmuir function as:

$$C_{ads} = \frac{aC^m}{1+bC} \qquad (2.14)$$

$$a = (a_1 + a_2 C_{SE}) \left(\frac{K_{ref}}{K}\right)^n \qquad (2.15)$$

Where C is the polymer concentration, m is the exponent for concentration dependence, C_{SE} is the salinity, k is grid block permeability, k_{ref} is the reference permeability, n is the exponent for permeability dependence, and a_1, a_2 and b are the adsorption coefficients.

Polymers can reduce the water-effective permeability where the degree of permeability reduction depends on the polymer type, molecular weight, shear effects and rock properties. The model used in ECLIPSE is:

$$R_k = 1 + (RRF - 1)\frac{C_p^{\propto}}{C_p^{\propto max}} \qquad (2.16)$$

Where: RRF, $C_p^{\propto}$ and $C_p^{\propto max}$ are the residual resistance, polymer adsorption and maximum adsorption capacity of the rock for polymer in phase α.

The viscosity of the polymer decreases by increasing the shear rate, especially near the injection wellbore. At low shear rates, μ_p is independent of shear rate, however, at higher shear rates the viscosity is reduced and finally a second plateau value, close to the water viscosity, will be achieved (Lake, 1989). For ECLIPSE, there is a table to input the shear thinning or thickening polymer viscosity as a function of water velocity where:

$$V_w = b_w \frac{F_w}{\phi A} \qquad (2.17)$$

$$\mu_{sh} = \mu_{w,eff}\left[\frac{1+(P-1)M}{P}\right] \qquad (2.18)$$

Where: b_w is the water formation volume factor, F_w is water flow rate, A is the flow area between a pair of wells, $\mu_{w,eff}$ is the water viscosity, μ_{sh} is polymer shear viscosity, P and M are viscosity thinning or thickening multipliers provided as input.

Relative permeability strongly depends on saturation of the wetting and non-wetting phases. A commonly used approach is to express the relative permeability and capillary pressure as a function of the normalized saturation. In 1964, Brooks and Corey proposed the following equations for relative permeabilities:

$$K_{rw} = K_{rw(s_{orw})} \left[\frac{s_w - s_{wcr}}{s_{w,max} - s_{wcr} - s_{orw}}\right]^{N_w} \quad (2.19)$$

And the relative permeability for the oil phase is calculated as:

$$K_{ro} = K_{ro(s_{w,min})} \left[\frac{s_{w,max} - s_w - s_{orw}}{s_{w,max} - s_{wi} - s_{orw}}\right]^{N_w} \quad (2.20)$$

Where: $S_{w,min}$ is minimum water saturation, S_{wcr} is critical water saturation, S_{wi} is initial water saturation and S_{orw} is residual oil saturation. N_o & N_w are Corey oil exponents.

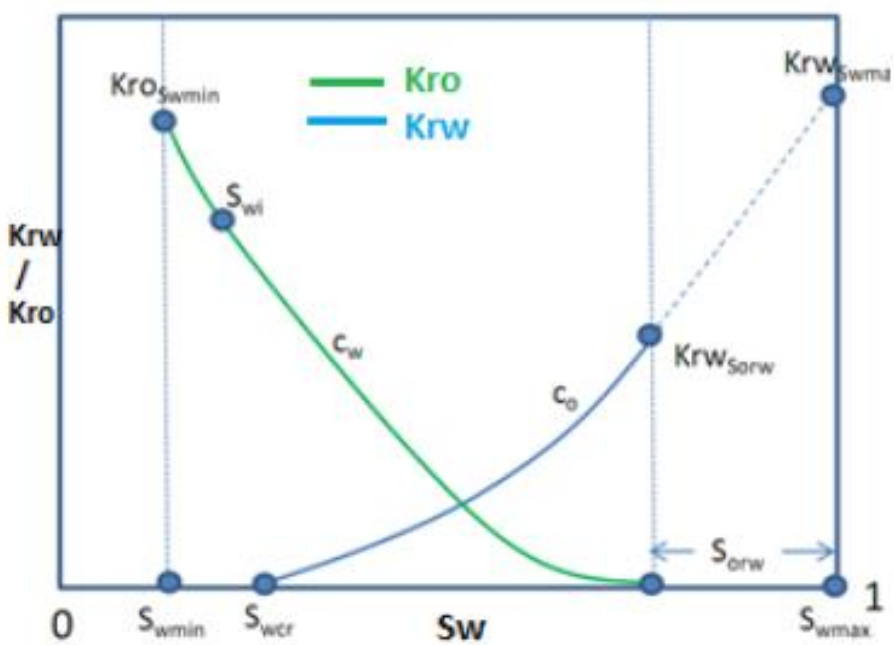


Figure 2.3: Standard Relative Permeability Curve

These saturation values are determined by core analysis, and the curve in between is generally interpolated with the default values of N_o and N_w. This results in uncertainty in simulations.

CHAPTER THREE: MATCHING LABORATORY EXPERIMENTS USING NUMERICAL SIMULATION

3.1 INTRODUCTION

Studies have shown that better displacement efficiency can be achieved within a range of polymer concentration and that the performance of ASP flood programmes is dependent on the right slug formulation, the injection rate and the overall project design (Taiwo et al., 2016). Therefore, the appropriate formulation of this slug needs to be determined and its formulation verified with the core flood experiment. The core flood experiment is described, and then followed by the methodology for its simulation.

The core flood experiment, which this work hopes to simulate, was done at the EOR laboratory at the University of Benin, Nigeria. The composition of the ASP slug used for the experiment is given in Table 3.1 below:

Table 3.1: Chemical slug composition

Materials	Names	Concentration
Alkaline	Sodium hydroxide (NaOH) (98 %)	1.0 wt %
Surfactant	Sodium dodecyl sulphate (SDS)	0.3 wt %
Polymer	Gum arabic	5000 ppm

A synthetic core was used for the core-flooding experiment. A core holder was packed with class IV soda lime glass spheres, washed with dilute NaH_2SO_4 to remove the polar charges present in them and then rinsed with warm water and dried. The core holder was vibrated with each incremental addition of beads. The core holder continued to be vibrated until the all the granular material was evenly and tightly packed. When no more glass beads could be loaded, the loading was stopped and the core holder was secured properly. The core holder was then saturated with brine to eliminate air. The properties of this core are given in Table 3.2 below.

Table 3.2: Core properties

Core properties	Values
Core type	Class IV soda lime glass spheres
Length (cm)	25.6
Bulk volume (cm^3)	112.93
Porosity (%)	0.3367
Pore volume (PV) (cm^3)	38
Permeability (mD)	1540
Oil flow rate (cm3/h)	60
Waterflood rate (cm^3/h)	60

3.2 CORE-FLOODING EXPERIMENT

Once the core was ready for flooding, the following steps were taken to chemically flood the EOR:

- Initial waterflooding was performed until a steady state was achieved. Secondary oil recovery was determined easily with gravity separation of the effluent. This was done at a constant flowrate of 60 cm^3/hr to achieve general residual oil saturation after waterflooding.
- The effluent fluids were collected in a burette and the waterflooding was stopped when the oil cut was less than 5 %. The residual oil saturation was then estimated based on the volume of oil in the burette.
- ASP flooding while close monitoring concentrations in the effluent was performed in order to check the performance of the formulation and to recover residual oil in the core as a form of tertiary recovery.
- Oil recovery and residual oil saturation were determined after chemical flooding by material balance and measuring the volumes of oil produced.
- Finally, the waterflooding was performed till residual oil saturation (S_{or}) was attained.

Table 3.3 below gives a summary of the results obtained from the core-flooding experiment.

Table 3.3: Core-flooding experimental results

Initial oil saturation	82 %
Initial water saturation	18 %
Waterflood	
Oil recovered	19.5 cm^3
Recovery	55 %
Residual oil	45 %
ASP flood	
Additional oil recovered	11.5 cm^3
Cumulative oil recovered	31 cm^3
Recovery	36.9 %
Residual oil	8.1 %
Residual recovery	82 %

Figure 3.1 below shows the system assembly for the flooding process with the high pressure core holder, measuring cylinder, heating jacket, dual pumps (for injecting crude oil and chemical slug) and pressure transducer, etc.

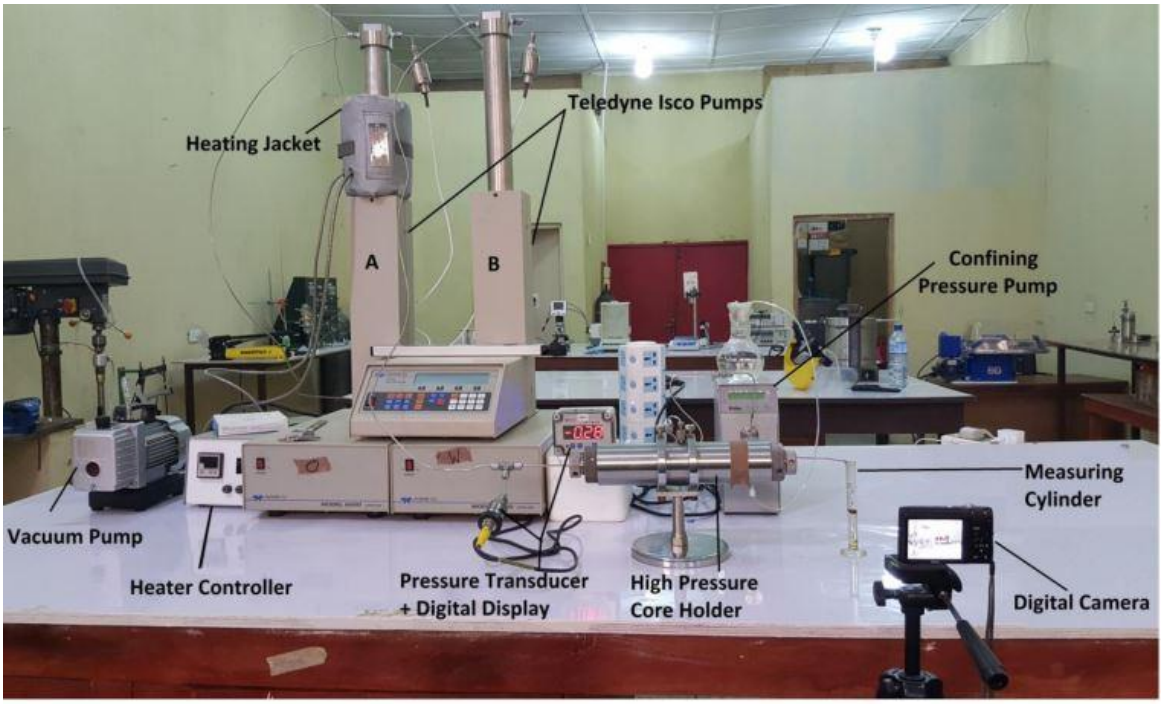


Figure 3.1: Experimental setup

Table 3.4 below gives the PVT properties of the reservoir fluid used for the core-flooding experiment.

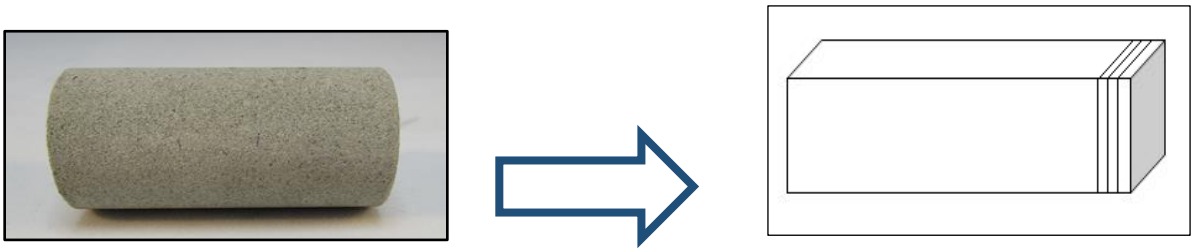
Table 3.4: Core-flooding PVT properties

PVT properties	Values
Initial water saturation	0.18
Residual oil saturation	0.45
Krw_max	0.8
Kro_max	0.4
Water viscosity (cp)	0.32
Water density (lb/ft^3)	62.37
Oil density (lb/ft^3)	57.76
Water compressibility (psi^{-1})	3.03E-06
Reference pressure (psia)	118

The values of maximum relative permeability (Krw_{max} and Kro_{max}) were used in plotting the relative permeability curves using the Corey equation.

3.3 CORE-FLOODING SIMULATION

A 1D model was developed in Eclipse™ by approximating a cylindrical plug in a cuboidal rock sample. The cuboid was then divided into 100 grid cells, as shown Figure 3.2:



Real core dimensions:
Diameter: 2.37 cm
Length: 25.6 cm

Cartesian model (1D): 100 X 1 X 1
Dx = 0.256 cm
Dy = Dz = 2.1004cm

Figure 3.2: Scheme for approximating a cylindrical plug in a cuboidal rock sample

The Eclipse™ model gave a pore volume of 38 cm^3, which is the same as the experimental pore volume. This model was maintained at a simplistic level to ensure a short simulation time along with ease of modification and debugging. Grid cells of 20, 50, 100, 200 and 500 were used to check for the optimum grid cells to use.

3.3.1 Dynamic simulation constraints

The dynamic model was bound with the following constraints, as per the laboratory experiments:

3.3.1.1 Initial constrains

- Constant bottom-hole pressure at the producing well = 118 psia = 8.02945 atma. This pressure is lower than in the actual reservoir. However, due to the absence of any gas in the reservoir, this difference in pressure did not alter flooding to any large extent.
- Constant inlet flow rate = 1 ml/min = 60 cm^3/hr.

3.3.1.2 Assumptions

- Core is completely homogenous;
- Corey law is applicable for relative permeability curves.

Corey Law:

$$K_{rw}\,(S_w) = K_{rw,or}\left(\frac{S_w - S_{cw}}{1 - S_{cw} - S_{or}}\right)^{n_w}$$

$$K_{ro}\,(S_w) = K_{ro,cw}\left(\frac{1 - S_w - S_{or}}{1 - S_{cwi} - S_{or}}\right)^{n_w}$$

Where: $K_{ro,cw}$ is oil-relative permeability at minimum water saturation;

S_{cw} is critical water saturation;

S_{cwi} is initial water saturation;

S_{or} residual oil saturation;

N_o & N_w are Corey oil exponents.

- Residual oil saturation values were found with terminal values of waterflooding and ASP.
- In the simulator all the grid blocks were set at initial saturations. The waterflooding and ASP processes were simulated to generate the oil production curve and oil recovery.

Table 3.5: Dynamics of flooding

Component	Concentration (ppm)	Approximate slug size (PV)
Initial waterflooding		7
ASP flood		0.3
Alkali	10,000	
Polymer	5000	
Surfactant	3000	
Final waterflooding		8

3.4 RESULTS AND DISCUSSION

A simple 100*1*1 model was built (using Eclipse™) with injection in the first cell and production in the last cell. Figures 3.3 and 3.4 show the saturation map for the water and oil flooding respectively in the core as shown by Floviz™ at the beginning of the flooding simulation.

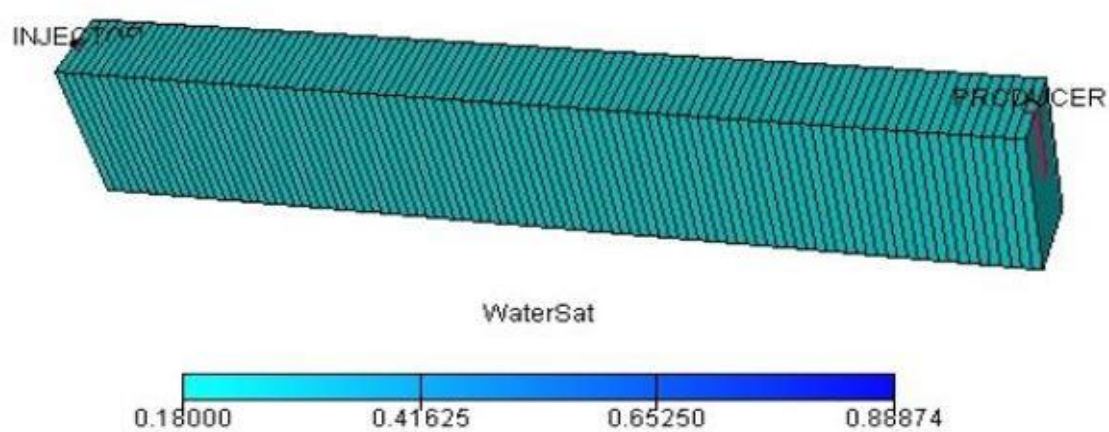


Figure 3.3: Water saturation map in flooding experiment

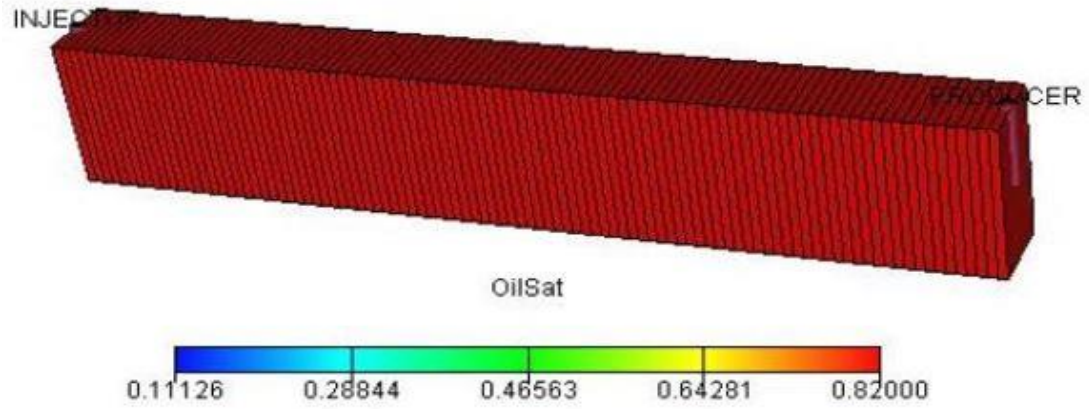


Figure 3.4: Oil saturation map in flooding experiment

The simulation results showed that, after injecting 7 PV of water into the core model, continual injection doesn't bring about additional recovery as the model is now producing at almost 100 % water cut, i.e., producing only water.

History matching is a common reservoir engineering technique used to update a geological model. The reservoir model was modified to match the response of the field during the production phase, and further extrapolated to predict the future response of the reservoir. This method is commonly used to fit oil production trends and bottom-hole pressure (BHP).

The simulation model was able to show a total oil production of 19.17 cm^3. This gives a waterflood recovery of 53 % as compared with a total oil production of 19.5 cm^3 and recovery of 55 % from the experimental core flood. (However, during the experiment the results of oil production and the pressure trend were not taken per PV of fluid injected, it was done only at the end of the experiment. Therefore a match of the pressure profile cannot be shown).

Figures 3.5, 3.6 and 3.7 plot the oil recovery vs pore volume of water injected, the water cut vs pore volume of water injected, and the total oil produced vs pore volume of water injected respectively.

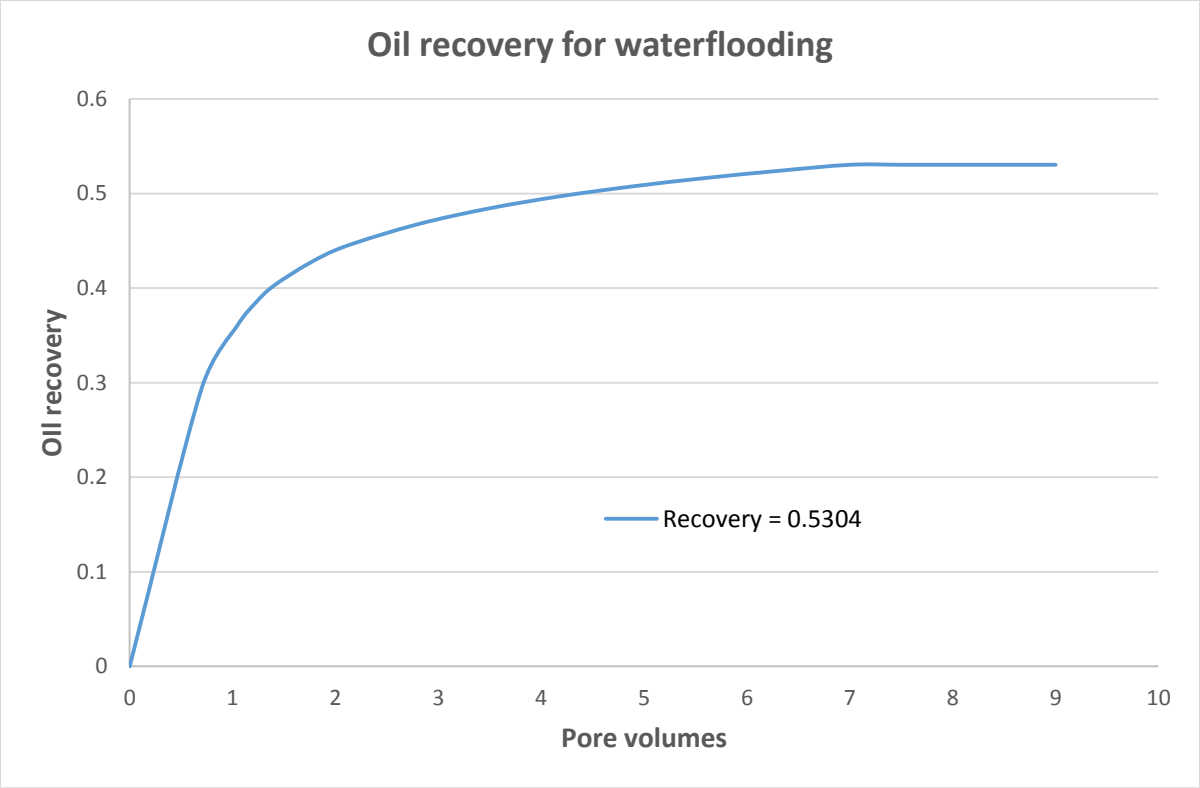


Figure 3.5: Oil recovery match for waterflooding

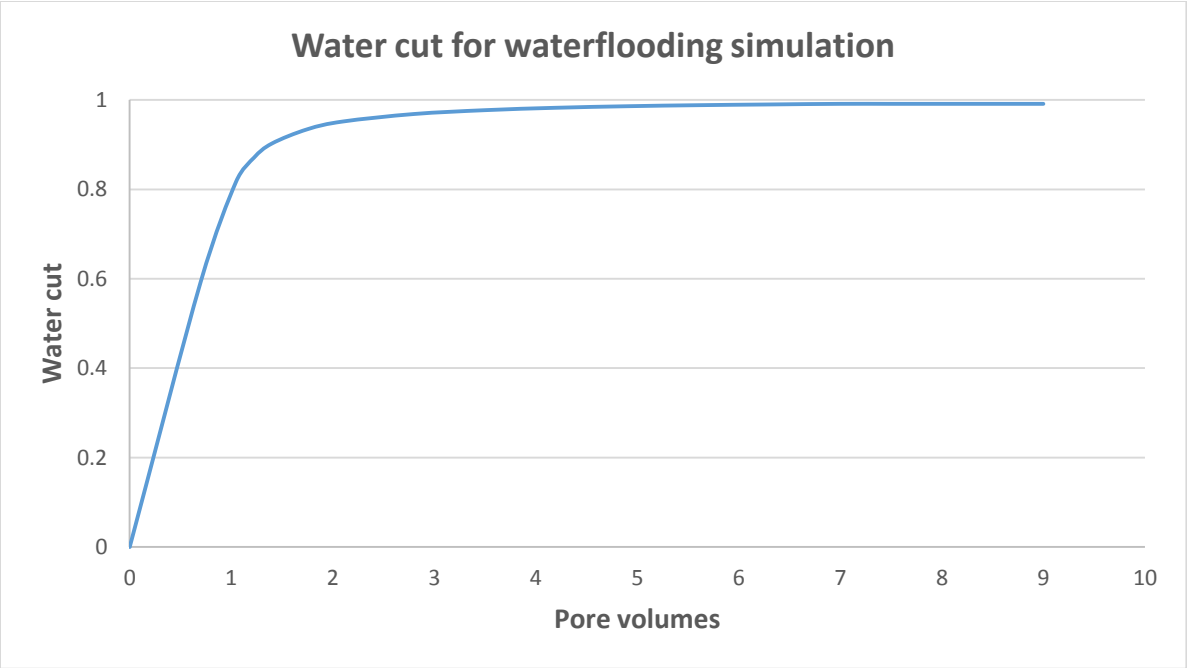


Figure 3.6: Water cut match for waterflooding

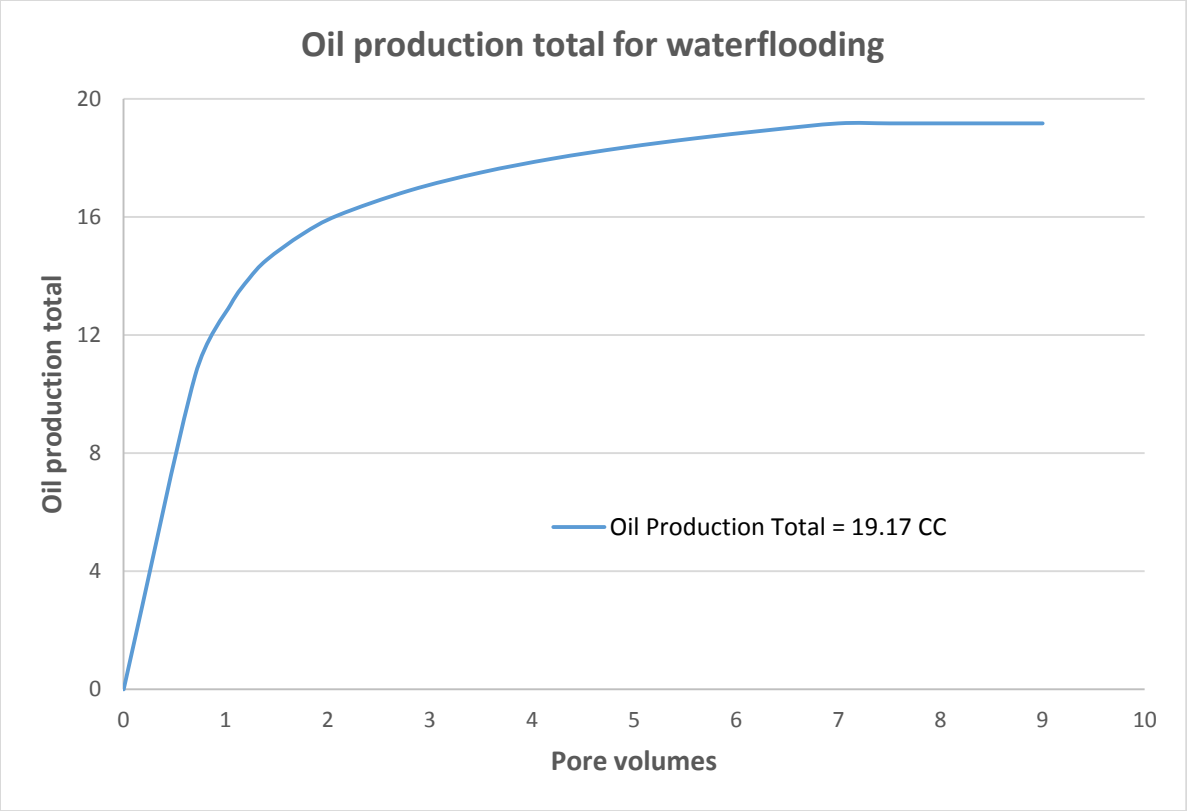


Figure 3.7: Oil production total match for waterflooding

Before beginning the simulation work, a sensitivity analysis was performed to see which number of grid cells would give a result closest to the experimental results. Grid cells of 20, 50, 100, 200 and 500 were used to establish the optimum number of grid cells to use. From Figure 3.8 it was concluded that, for this simulation model, grid cell variation has little to no effect on the oil recovery as the recovery ranged from 52 % to 53 %.

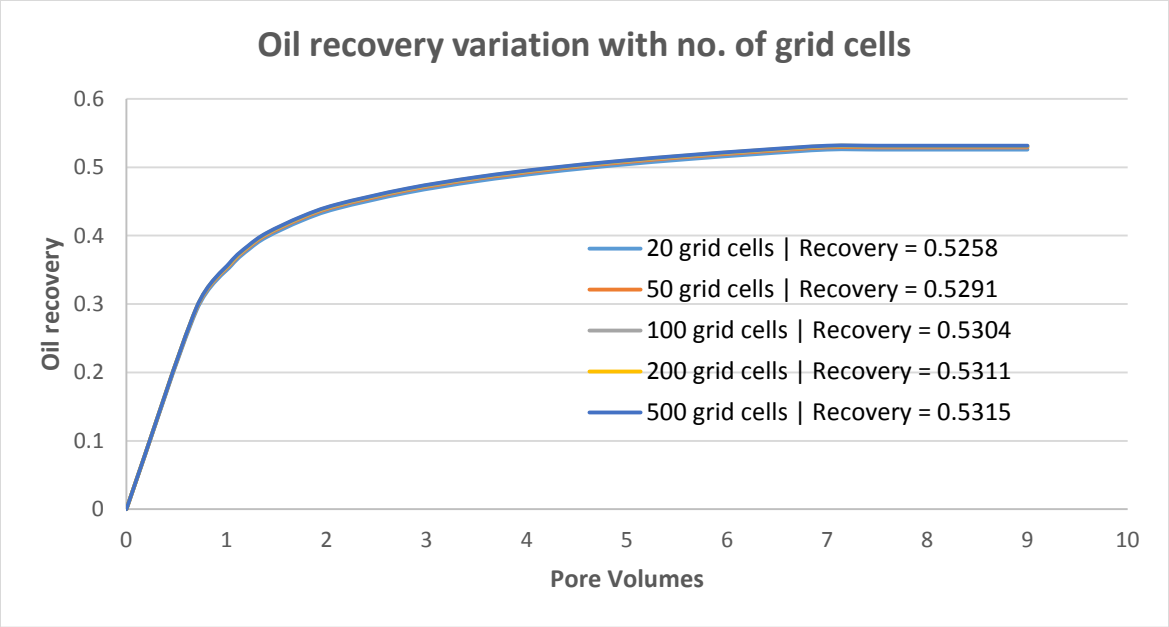


Figure 3.8: Oil recovery variation with number of model grid cells

Having matched the waterflood simulation of the ASP flooding started. The concentration of the ASP injected is shown in Table 3.6. The simulation model was able to show a total oil production of 29.12 cm^3, this gives an ASP flood recovery of 80.53 % compared with a total oil production of 31.0 cm^3 and recovery of 82 % from the experimental core flood.

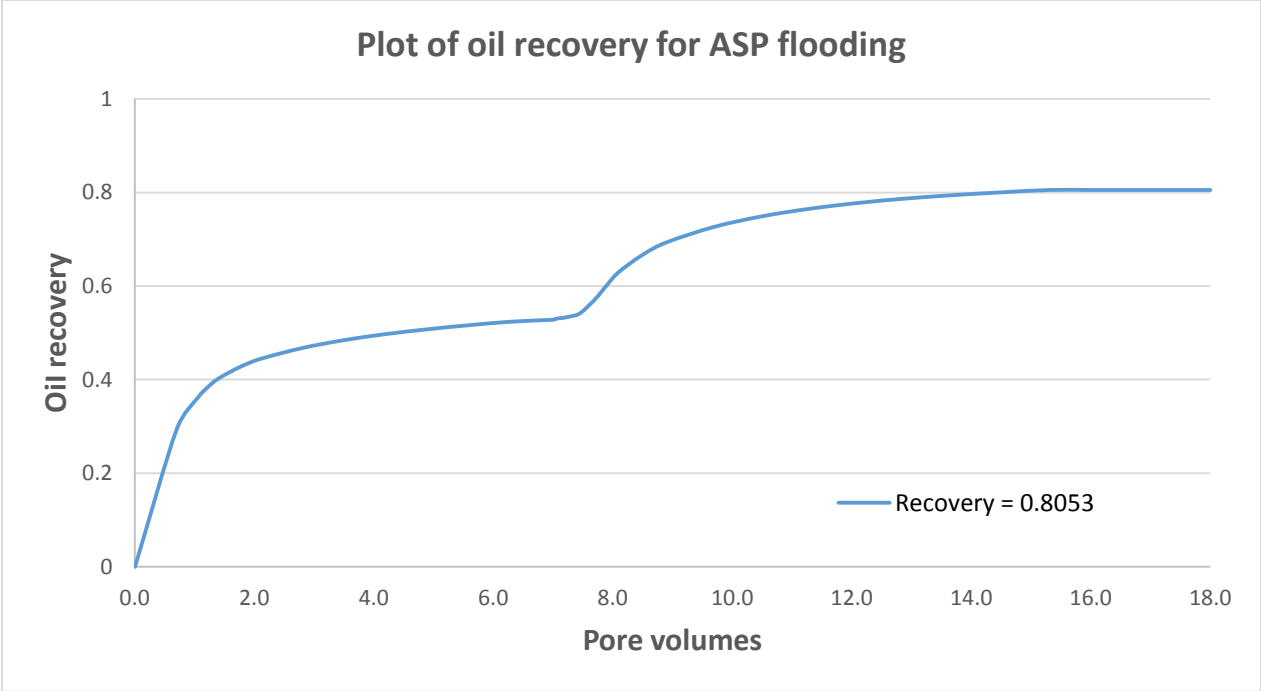


Figure 3.9: Oil recovery for ASP flooding

The rise in oil recovery is due to alterations of the contact angle between the oil-water-rock equilibrium, which mobilizes more oil. These alterations in the contact angle are due to the presence of the alkali and the surfactant.

Table 3.6: Flooding results summary

Parameter	Core-flooding model	Simulation model
Water flood		
Oil recovered	19.5 cm^3	19.17 cm^3
Recovery	55 %	53.04 %
ASP flood		
Oil recovered	31 cm^3	29.12 cm^3
Recovery	82 %	80.53 %

3.4.1 Sensitivity analysis

This involves the study of the effect of alterations in individual parameters of the system on final outputs. Trends of variations of output parameters with marginal change of an input parameter were plotted. In addition, extreme cases were generated to rectify boundary assumptions. Sensitivity analysis plays an important role in understanding systems with multiple variable parameters. Core flooding is dependent on different parameters therefore sensitivity analysis is often used to explore optimized flooding in reservoirs as well as plugs.

Table 3.7: Sensitivity analysis parameters summary

Parameter	Base case	Sensitivity analysis values / multipliers
Injection rate	60 cm^3/hr	Keeping injection time constant: cm^3/h Keeping injected PV constant: 30 cm^3/h, 90 cm^3/h and 120 cm^3/h
PV of ASP injected	0.3 PV	PV variation at 0.1, 0.5, 1.0 and 1.5 PV of ASP injected
Viscosity (polymer concentration)	5000 ppm	Viscosity variation with polymer concentration variation: 0 ppm, 500 ppm, 2500ppm, & 10000 ppm

3.4.1.1 Injection rate

Initially, models that were generated for sensitivity analysis of the injection rate had equal pore volumes injected at each phase, as the base case. This was achieved by adjusting injection time. One model was developed with half of the volume injected at each stage of injection, without altering total injection time. Therefore, total pore volume injected became half. Injection rate is one of the important parameters to be adjusted in reservoir engineering because of the following pros and cons:

- Injection rates are limited by fracking pressure. Above a certain pressure, there is a risk of fracking the reservoir, thus losing injection water to some unknown point of the reservoir.

- Higher injection rates will increase the production rate; saving money in terms of time.
- Higher injection rates have a higher risk of unswept oil volume (poor volumetric sweep efficiency) if not monitored well.

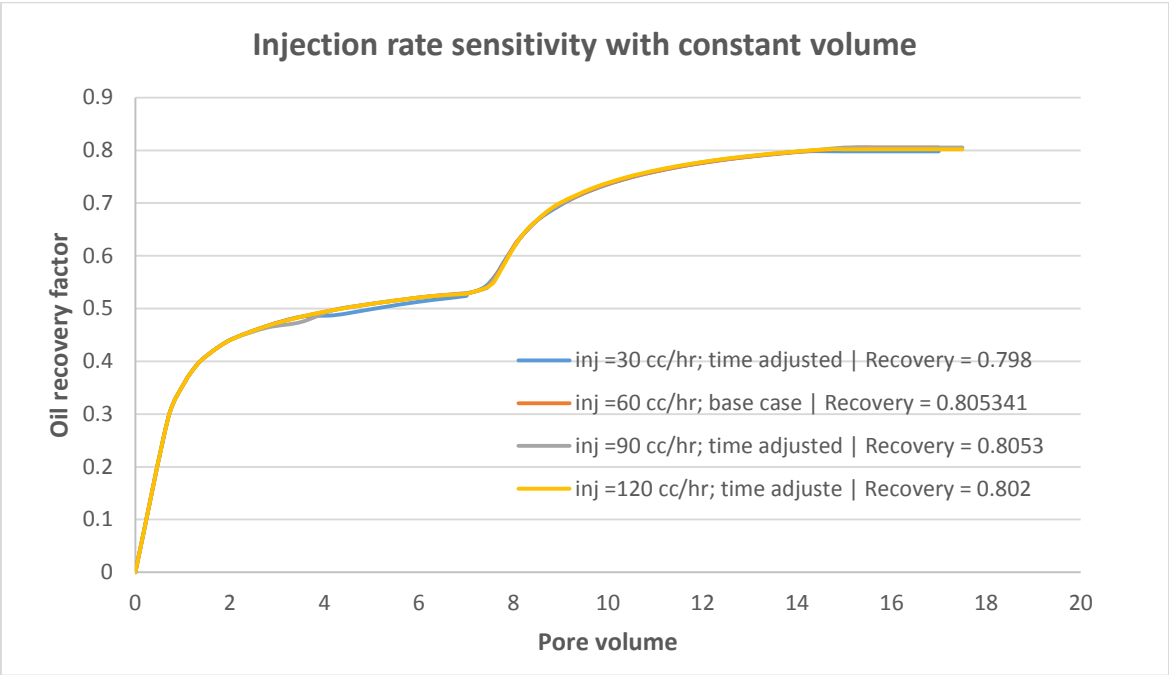


Figure 3.10: Injection rate sensitivity with constant volume

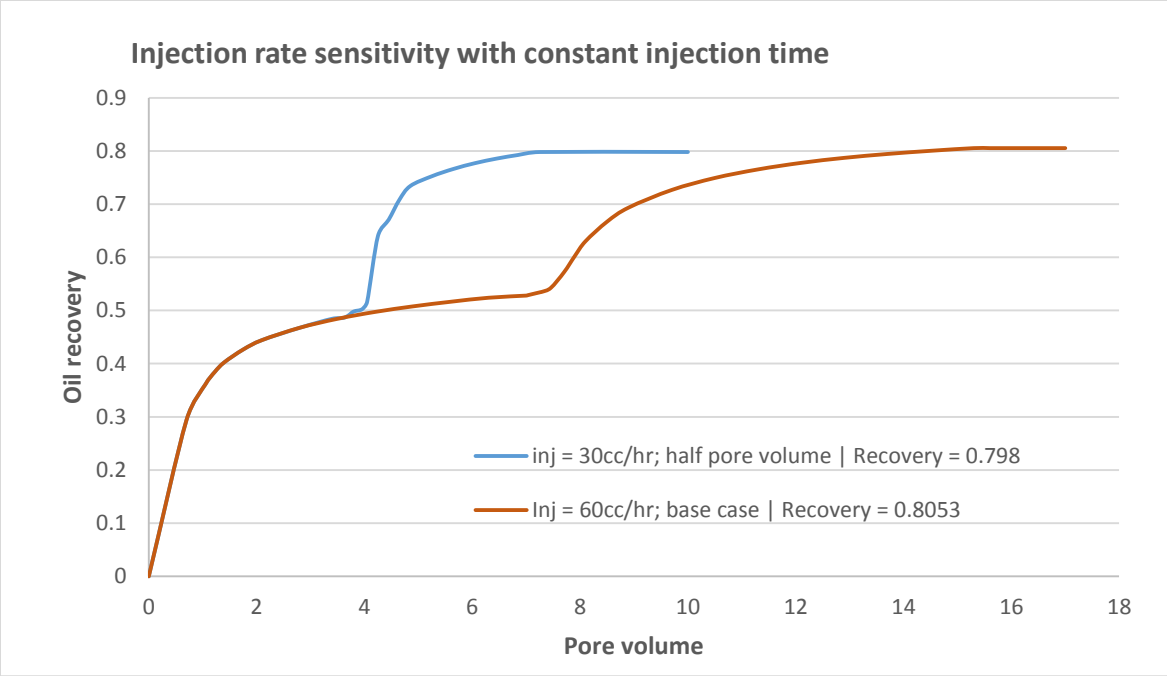


Figure 3.11: Injection rate sensitivity with injection time

All injection rates (for constant pore volume injection) show similar production behaviour. Despite injecting lower injection volumes, the simulation of an injection rate of 30 cm^3/hr nearly reached a similar total oil recovery factor. This can be explained with long injection of waterflooding to achieve a steady state.

3.4.1.2 Viscosity (polymer concentration)

Viscosity variation is mainly caused by the polymer concentration. As discussed earlier, polymers give a stable waterfront to flooding. This results in higher volumetric sweep efficiency. Following are the pros and cons of the polymer concentration variation:

- Higher polymer concentration will increase injection pressure; resulting in increased injection cost.
- Lower polymer concentration will not create a stable waterfront and might cause a fingering effect.

- Higher polymer viscosity can cause blockage of small pores at the injection point, resulting in reduced efficiency of the injector well.

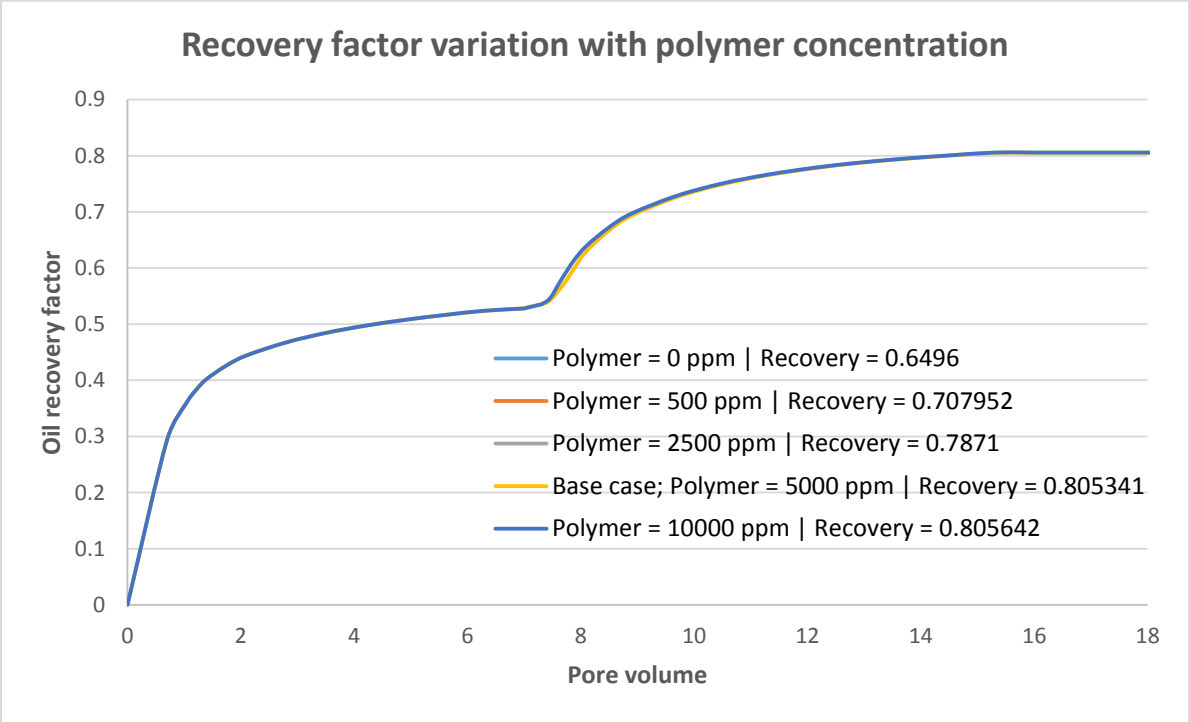


Figure 3.12: Results of sensitivity analysis for polymer concentration

With the increasing polymer concentration, the recovery factor increased. However, at a lower range of polymer concentration, there was a marginal increase in the recovery factor compared to a marginal increase in the higher concentration of polymer. This can be attributed to the stabilization of the waterfront. Due to a stable waterfront above 5000 ppm, polymer concentrations above it resulted in an almost equal recovery factor but at a higher injection cost.

3.4.1.3 PV of ASP injected

Sensitivity analysis on the pore volume of the ASP injected was carried out to identify the optimum value of the ASP slug that should be injected. With increasing pore volume of ASP slug injected, the recovery factor also increased, although the increase was minimal.

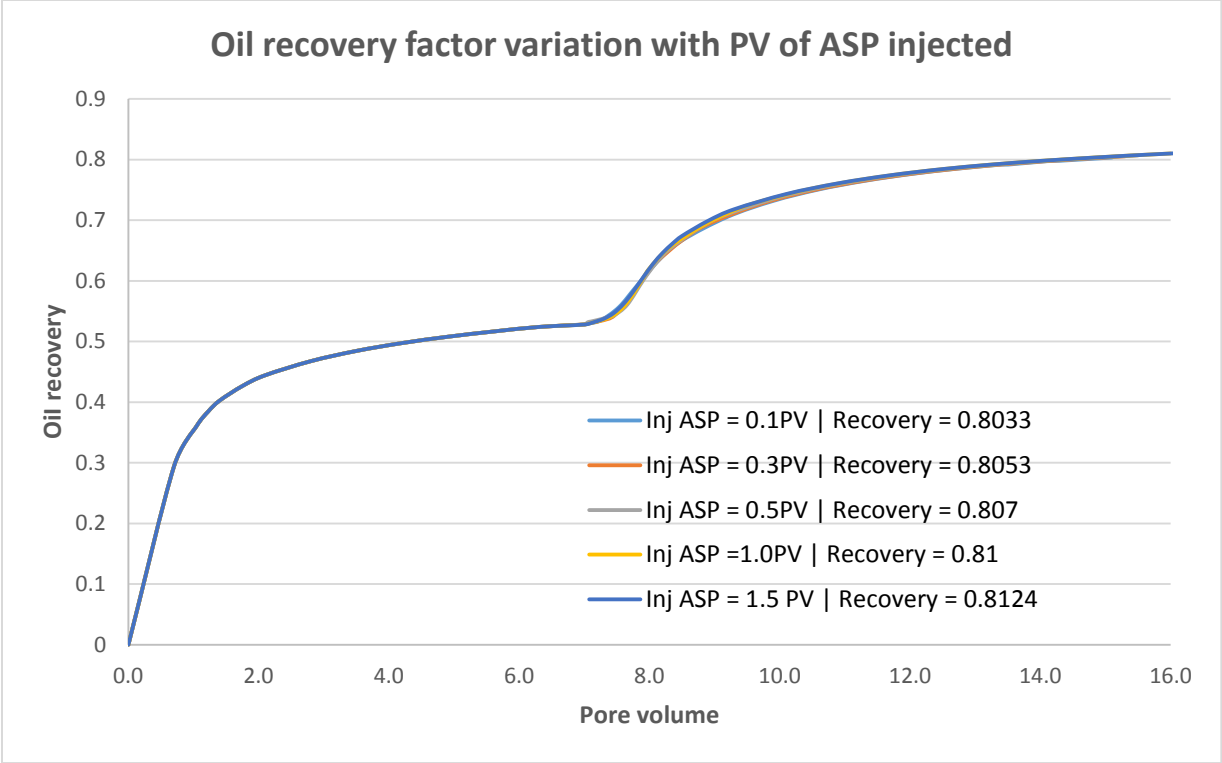


Figure 3.13: Results of sensitivity analysis for PV of ASP injected

3.5 FIELD SIMULATION MODEL

Assuming a synthetic reservoir of three layers with varying permeabilities, a 10 x 10 x 3 grid was built in Eclipse™ with negligible capillary pressure to run a 3D field scale reservoir simulation. The flow rates of both the injection and production wells were set at 1258 stb/d. All the characteristics of the model have been summarized in the table below:

Table 3.8: Eclipse model characteristics

	Layer 1	**Layer 2**	**Layer 3**
Blocks	100	100	100
Reservoir top depth	2600 ft	2600 ft	2600 ft
Layer depth	0.58 ft	0.84 ft	0.47 ft
Porosity	25 %	25 %	25 %

Permeability X and Y	4500 md	3300 md	2400 md
Permeability Z	1050 md	1800 md	500 md

Table 3.9: Reservoir PVT properties (SI units)

PVT properties	Values
Initial water saturation	0.2
Residual oil saturation	0.3
Krw_max	0.8
Kro_max	0.5
Water viscosity	0.88
Water density	998
Oil density	850
Water compressibility	4.6E-06
Reference pressure	270

Table 3.10 Dynamics of ASP flooding for reservoir

Component	Concentration (ppm)	Approximate flooding duration (days)
Initial waterflood		600
ASP flood		50
Alkali	10 000	
Polymer	5 000	
Surfactant	3 000	
Final waterflood		600

The saturation maps below show the end of the reservoir during the simulation process. Figure 3.14 shows the initial oil saturation before the flooding started. On injecting water it can be observed how the saturation profile changed as the injected fluid moved towards the producer (Figure 3.15).

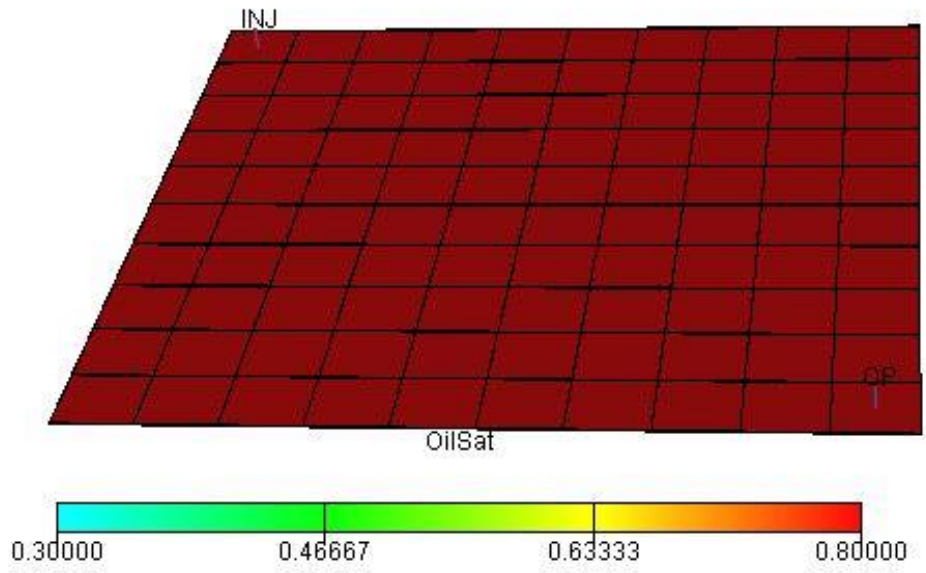


Figure 3.14: Oil saturation map in reservoir at beginning of simulation

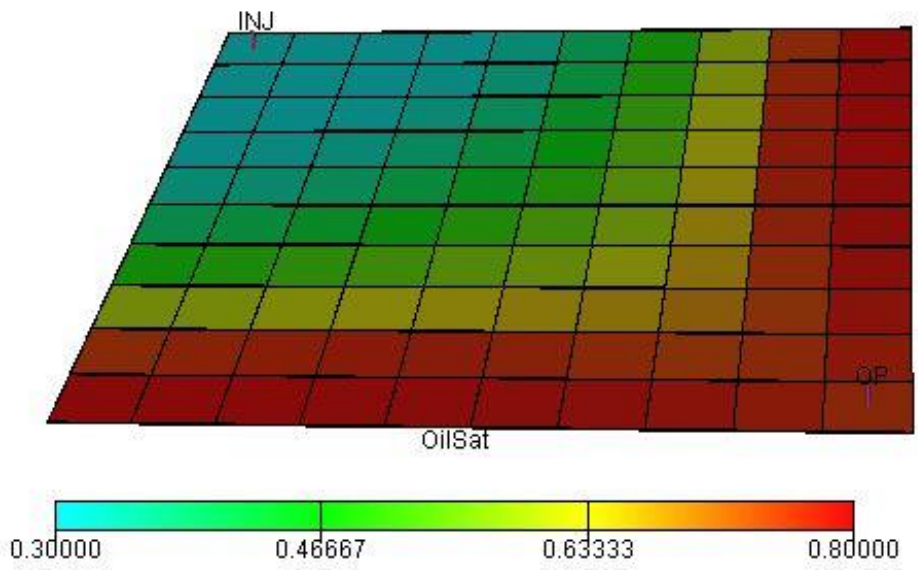


Figure 3.15: Oil saturation map in reservoir during the waterflood simulation

After about 400 days of water injection, the oil saturation in the reservoir no longer changed with the continual injection of water (Figure 3.16).

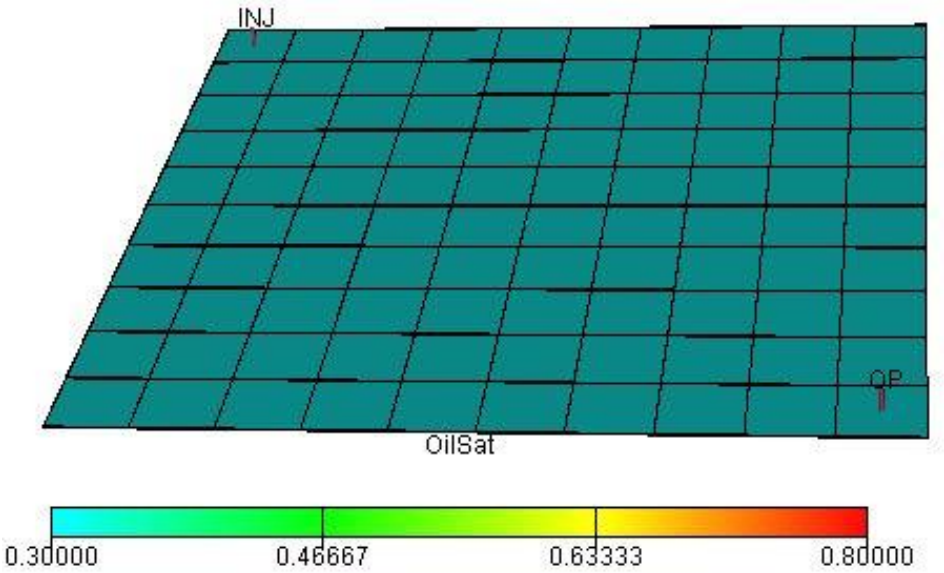


Figure 3.16: Oil saturation map at the end of the waterflooding simulation

The ASP slug was injected, followed by waterflooding. The field study proved that the formulated ASP slug was effective as it had reduced the oil left in the reservoir, as shown in the saturation maps (Figure 3.17).

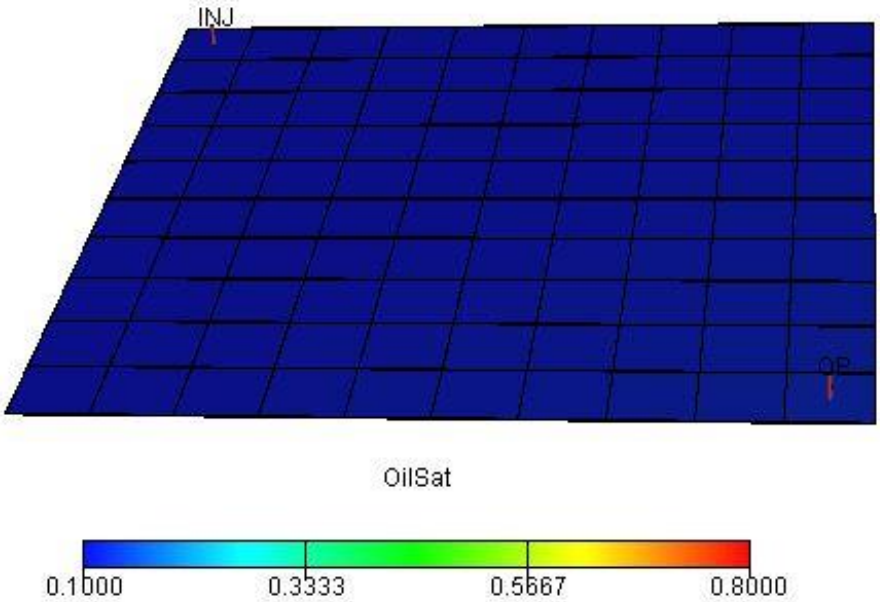


Figure 3.17: Oil saturation map at the end of the ASP flood simulation

The total oil production and oil recovery increased from 10 516.51 STB and 62.48 % at the end of the waterflooding to 14 387.325 STB and 85.8 % respectively on addition of an ASP slug. This was an additional recovery of 3870.815 STB.

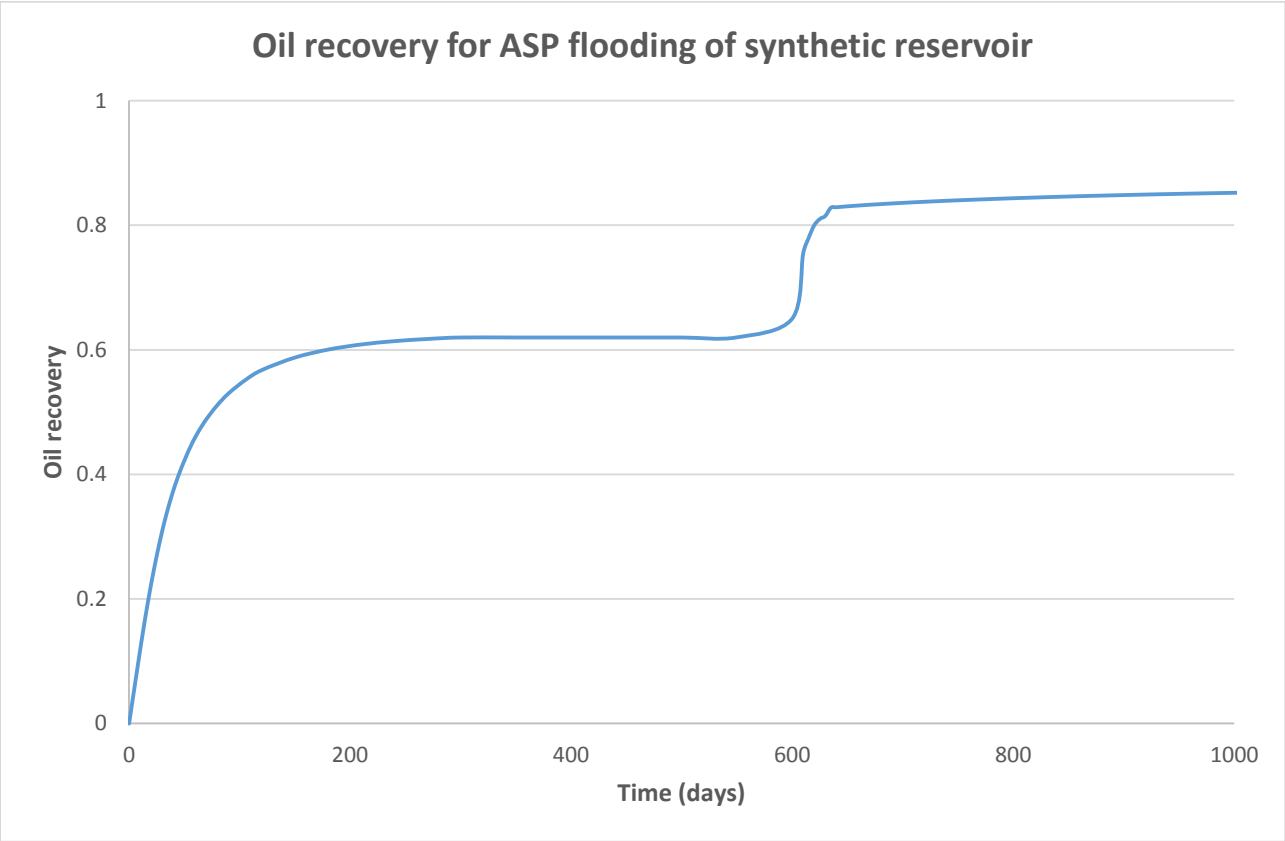


Figure 3.18: Oil recovery profile for ASP flooding of the synthetic reservoir

CHAPTER FOUR: CONCLUSION AND RECOMMENDATIONS

4.1 SUMMARY

This study shows that the numerical simulation of ASP core flooding using gum arabic as a polymer can be done using Eclipse™ as simulator. It was done by matching a core-flooding experiment using gum arabic and formulating an optimal ASP system that reduced residual oil saturation to a minimum to improve oil recovery.

It is important that the ASP slug injected in a core or reservoir is clear and aqueous-stable in order to achieve high residual oil recovery (Onuoha & Olafuyi 2013). This was validated in core-flood experiments conducted in their study. They also showed that the addition of co-solvents helps in achieving aqueous phase stability that ensures the injected mixture is clear. Stability helps with the problem of phase separation and transport in the reservoir over long distances with low retention.

The aim of this research work was to determine the suitability of gum arabic as a polymer for EOR operations using numerical simulation. The objective of this study includes:

- History matching the simulation model to match the core flooding;
- Investigating the effects of polymer concentration on oil recovery;
- Running a sensitivity study on slug parameters to study the slug's performance;
- ASP slug extrapolation & performance testing for a synthetic reservoir.

The entire work was done using the following workflow:

- A linear ASP coreflooding was done using gum arabic as the polymer of the core (Class IV Soda Lime Glass Spheres). The various parameters necessary for building the simulation model were obtained from this core-flooding experiment.
- A 1D model of grid 100*1*1 was built using the parameters obtained from the core-flooding experiment.

The waterflooding and ASP flooding were simulated using this model, and the result agreed with the experimental result by changing certain parameters, especially the relative permeability curve.

- After the matching, a sensitivity analysis was carried out on: injection rate, PV of ASP injected and viscosity (polymer concentration). The effect of alterations in these parameters of the system on final outputs was studied. Trends of variations of output parameters with marginal change of an input parameter are plotted. Sensitivity analysis plays an important role in understanding systems with multiple variable parameters.
- After an optimum slug formulation was identified, reservoir testing of gum arabic as a polymer for ASP flooding was carried out. A synthetic reservoir of three layers with varying permeabilities was assumed, then a 10 x 10 x 3 grid was built in Eclipse™ with negligible capillary pressure to run a 3D field scale reservoir simulation. The flow rates of both the injection and production wells were set at 1258 stb/d.

4.2 CONCLUSIONS

At the end of this work, the following conclusions were drawn:

- A simulation model that matches the gum arabic core flooding was built using a black oil simulator Eclipse™.
- Grid cell variation has little to no effect on the oil recovery on the core as recovery ranged from 52 % to 53 % with waterflooding.
- Sensitivity analysis of injection rates (at constant pore volume injected) showed similar production behaviour. Despite a lower injection volume, over a similar time, the lower injection rate almost reached the same total oil recovery factor as the long injection of waterflooding.
- Sensitivity analysis of viscosity showed the expected trend of increasing the viscosity of the injected flooding resulting in increased oil production.
- Sensitivity analysis of the pore volume of the ASP injected showed that the recovery factor increased with increasing pore volume of ASP-injected slug, although the increase was minimal.

- Extrapolating from core to field simulation, the ASP slug formulated was able to increase the total field oil production by increasing recovery from 62.48 % at the end of the waterflooding to 85.8 %.
- Gum arabic has proved to be an effective polymer for EOR operations.

4.3 FUTURE WORK:

All models in this work were simulated with a black oil simulator, ECLIPSE 100 (2010.1). Although black oil simulators give reliable simulation results for core-flooding experiments, pore scale simulators are ideal for core-flooding simulations.

One of the prominent advantages of the pore-scale simulator is generating relative permeability curves for the given plug as an output, on the basis of petro-physical properties of the rock-oil-water system. On the contrary, black oil simulators need a relative permeability curve as an input for simulations. Developing the same dynamic model in pore scale simulators will help to understand different aspects of core flooding.

Sensitivity analysis should be extended to other properties or variables of the flooding while, for more detailed sensitivity analysis, atomization of the history matching should be made with Matalb or Python.

APPENDIX: ECLIPSE INPUT FILE FOR ASP FLOODING

```
--AFRICAN UNIVERSITY OF SCIENCE AND TECHNOLOGY
--EMMANUEL AKANINYENE AKPAN
--COREFLOODING 1D MODEL, AUGUST 2017

RUNSPEC
==============================================================
--NOSIM
TITLE
ASP Flood
DIMENS
-- size of the grid i,j,k
100 1 1 /
OIL
WATER
POLYMER
SURFACT
ALKALINE
NOECHO
LAB
TABDIMS
-- to account for tables inserted in the data file
 2 1 30 30 /
REGDIMS
-- connected to FIPNUM | the maximum number of fluid-in-place regions
 1 /
WELLDIMS
-- initiating well geometry
 2 1 2 1 /
START
 1 AUG 2017 /
NSTACK
 10 /
UNIFOUT
-- to have a single output file for restart and summary
UNIFIN
-- to have a single input file for restart and summary
```

```
GRID
==============================================================
INIT
-- to produce file with initial conditions which can be read in PETREL
OLDTRAN
GRIDFILE
-- detailed output file
 1 1 /
DXV
 100*0.256 /
DYV
 2.37 /
EQUALS
-- function used to same value for many grid points
 TOPS 0 0 1 100   1 1    1 1 /
 'DZ' 2.37 1 100   1 1    1 1 /
/
PERMX
100*1540 /
PORO
100*0.3367 /

COPY
   PERMX   PERMY /
   PERMX   PERMZ /
/
MULTIPLY
-- change Kv/Kh
-- prop   multiplier i1 i2  j1 j2  k1 k2
   PERMZ 0.1  1  100  1  1  1  1 /
/
RPTGRID
 DX DY DZ PORO PERMX PERMY PERMZ POLYMER /
EDIT
-- This is where fluid and rock properties are specified

PROPS
==============================================================
SWFN
-- Sw     Krw     Pc
0.05     0                          0
```

0.1	0	0
0.15	0	0
0.2	0.010518472	0
0.25	0.047297078	0
0.3	0.090309649	0
0.35	0.137168809	0
0.4	0.186906273	0
0.45	0.238975389	0
0.5	0.293019576	0
0.55	0.348785747	0
0.6	0.406083936	0
0.65	0.464765723	0
0.7	0.524711609	0
0.75	0.585823093	0
0.8	0.648017431	0
0.85	0.711224034	0
0.9	0.775381896	0
0.95	0.840437711	0
1	0.906344459	0 /

/

SOF2

-- So	Kro
0.05	0
0.1	0
0.15	0.00079295
0.2	0.007102445
0.25	0.017938837
0.3	0.032566557
0.35	0.050596379
0.4	0.071770062
0.45	0.095897792
0.5	0.122831362
0.55	0.152450301
0.6	0.184653812
0.65	0.219355715
0.7	0.256481059
0.75	0.295963769
0.8	0.337744936
0.85	0.381771549

```
0.90     0.427995521
0.95     0.476372935
1        0.526863443   /
/

PVTW
-- water PVT

--  Pref (atm)   Bw (rcc/scc)   Cw (1/atm)   Vw (cP)   Cvw (1/atm)
     1  1.0019   4.451E-05  0.32  0.0 /

PVDO
-- dead oil PVT
--  Poil (atma)   Bo (rcc/scc)      Vo (cP)
   4.01471   1.0470     5.354
   4.55908   1.0458    5.360
   4.76322   1.0454    5.362
   5.44368   1.0443    5.370
   6.8046     1.0427     5.391
   13.6092   1.0396    5.548
/
ROCK
-- Pref (atma)    rock compressibility (1/atm)
127.246 0.000441 /

DENSITY
-- oil (g/cm3)   water (g/cm3)  gas  (g/cm3)
 0.8115 0.99907156 0.0009878586363 /
------------------------------------------------------------
--Alkaline keywords:
--Polymer adsorption multipliers as a function of alkaline concentration - no data available
ALPOLADS
-- Alkaline                polymer adsorption
-- concentration (g/cm3)       multiplier
 0.00           1.00
 0.029957     0.99 /
 0.00            1.00
 0.029957    0.99 /

-- Surfactant adsorption multipliers as a function of alkaline concentration
```

```
ALSURFAD
-- alkaline concentration (g/cm3)        adsorption multiplier
0.00          1.00
 0.029957   0.99 /
 0.00          1.00
 0.029957     0.99 /

-- Alkaline adsorption
ALKADS
-- Alkaline concentration (g/cm3)     Alkaline adsorbed on rock (g/g)
0.000           0
0.000999       5.2E-04
0.005991       5.2E-04 /
0.000           0
0.000999       5.2E-04
0.005991       5.2E-04 /

-- Alkaline-rock properties
-- 1 for desorption and 2 for no desorption
ALKROCK
 2 /
 2 /

ALSURFST
-- alkaline concentration (g/cm3)        water-oil IFT multiplier
0.00            1.00000
0.000999     0.95833
0.002996     0.91667
0.004993     0.87500
0.00699       0.83333 /
------------------------------------------------------------
--POLYMER KEYWORDS
PLYVISC
-- g/cm3    water viscosity multiplier
  0.0         1.0
  0.160185     10.0 /

-- Polymer-Rock Properties
-- adsorption index = 1 for desorption      adsorption index = 2 for no desorption
```

```
PLYROCK
0.02 1.2 1.95454 2 0.000005 /
0.02 1.2 1.95454 2 0.000005 /

-- Polymer Adsorption--data is not available
PLYADS
-- polymer conc. (g/cm3)       polymer adsorbed by rock
0.000      0.000E+00
0.000399      5.000E-09
0.001198      5.000E-09 /
0.000      0.000E+00
0.000399      5.000E-09
0.001198      5.000E-09 /

-- Polymer Todd-Longstaff mixing parameter, defines desegregation between water and
polymer solution (w = 1 completely mixed)
TLMIXPAR
 1.0 /

-- Polymer shear behaviour
PLYSHEAR
-- (cm/hr)
0.0000                    1
0.03              1
0.0599            1
0.1181            1
0.1500            1
0.4500            1
0.5999            1
1.5000            1
3.0000            1
4.5000            1
6.0000            1
15.000            1
29.999            1 /

-- Polymer-Salt Concentrations for mixing - maximum polymer and salt concentrations
PLYMAX
-- poly conc       salt conc
0.000999  0 /
```

```
------------------------------------------------------------
-- SURFACTANT KEYWORDS
--Surfactant solution viscosity function (NTPVT)
SURFVISC
-- surfactant conc. (g/cm3)        solution water viscosity (cp)
0.00            0.32
0.029957      0.32 /

--Surfactant adsorption functions Berea
SURFADS
-- surfactant conc. (g/cm3)    conc of surfactant adsorbed by the rock (g/g)
0.000            0.000E+00
0.005991       0.000115 /
0.000             0.000E+00
0.005991       0.000115 /

SURFST
-- surf conc  (g/cm3)   water-oil surface tension (dynes/cm)
0.00        1751268
0.000029    875634
0.000043    350253
0.000057    175126
0.000071    17512 /

--Surfactant capillary de-saturation functions
SURFCAPD
--log of the capillary number         miscibility function

-8    0.0
-7    0.0
-6.7  1.0
-1    1.0 /
-8    0.0
-7    0.0
-6.7  1.0
-1    1.0 /

-- Specifies the surfactant-rock properties - desorption, mass density rock (NTSFUN)
-- index = 1 for desorption       index = 2 for no desorption
SURFROCK
```

```
----desorption index     mass density of this rock (g/cm3)
2  1.95454  /
2  1.95454  /

SOLUTION
==============================================================
PRESSURE
-- initial pressure in all blocks  (atm)
 100*8.02942 /
SWAT
-- initial water sat
 100*0.18 /
RPTSOL
  RESTART=1  FIP=3  /

SUMMARY
==============================================================
-- This keyword asks Eclipse to output wct
WWCT
/
-- This keyword asks Eclipse to output water rate
WWPR
/
-- This keyword asks Eclipse to output oil production rate
WOPR
/
FOIP
FOE
FOPT
WPI
/
-- This keyword asks Eclipse to output water saturation rate
BSWAT
100     1        1/
/
-- This keyword asks Eclipse to output oil production total
WOPT
/
-- This keyword asks Eclipse to output block oil saturation
-- well pressures
BPR
```

```
1 1 1  /
 /
BPR
100 1 1  /
/
BSOIL
100     1         1/
/
-- field pressure
FPR
-- water injection rate
FWIR
-- Requests a neat tabulated output of the summary file data at the end of the run.
RUNSUM
-- Requests RUNSUM output to be in Microsoft Excel format.
EXCEL

SCHEDULE
==============================================================
RPTSCHED
 'SGAS'  'RS'  'RESTART'  'FIP=2'  'WELSPECS'  'WELLS=2'  'SUMMARY=2'  'AQUCT'
'NEWTON' /
RPTRST
 BASIC=3 FREQ=5 /

WELSPECS
 INJECTOR  I    1  1  0.00  WATER 3* NO  /
 PRODUCER  P  100  1  0.00  OIL   3* NO /
/

COMPDAT
 INJECTOR    1  1  1  1  OPEN  2*  0.001 /
 PRODUCER  100  1  1  1  OPEN  2*  0.001 /
/
--WATERFLOODING 1
WCONPROD
 PRODUCER  OPEN  BHP  5*  8.0158145 /
/
WCONINJE
 INJECTOR  WATER  OPEN  RATE  60 1* 20 /
/
```

```
TSTEP
10*0.44333333 /


--EOR ASP FLOODING
WPOLYMER
INJECTOR       0.209696         0 /
/
WSURFACT
 INJECTOR       0.125818 /
/
WALKALIN
INJECTOR       0.419392 /
/
TSTEP
10*0.019 /



--WATEREFLOODING 2
WCONPROD
 PRODUCER  OPEN  BHP  5*  8.0158145 /
/
WCONINJE
 INJECTOR  WATER  OPEN  RATE  60 1* 20/
/
TSTEP
10*0.50666667  /
END
```

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