

بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ



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**Designing Of An ASP Flooding In A Well Pair For
Sudanese Oilfields (Case Study Hegilg Main)**

**تصميم غمر ASP في بئرین في الحقول السودانية (حقل هجليج
الرئيسي)**

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Dedication

This study is wholeheartedly dedicated to our beloved parents, who have been our source of inspiration and gave us strength when we thought of giving up, who continually provide their moral, spiritual, emotional, and financial support.

To our supervisor **Eng. Husham Awadelssed Ali** for his guidance and support.

To our brothers, sisters, relatives, mentor, friends, and classmates who shared their words of advice and encouragement to finish this study.

To Eng. Musab Fathalrahman for help us throughout this study and all Bisco staff for their help throughout the course.

There are many more people we could thank, but time, space, and modesty compel us to stop here.

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We would like to express our deepest appreciation to all those who provided us the possibility to complete this report.

A very special thanks to our families , fathers and mothers who were there for us always ,for encouraging us ,for just being there to picks us up every time we fall, this could not have happened without them.

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Abstract

Chemical Enhanced Oil Recovery (cEOR) can increase the recovery factor for many oilfields. Heglig oilfield is a suitable candidate for cEOR operations but, no study has been implemented to optimize ASP injection and production parameters in only two wells for this field.

The field is located at the southeast and middle of Block 2B, Muglad Basin, and it is one of the largest oilfields in Sudan, it has been producing oil since 1999, its oil production was reported to have peaked in 2006, and declined ever since. The field is composed of a sequence of massive and continuous sandstones interceded with shales.

The most water production problems in Sudan were observed in this field, and the water cut has reached 95% . This study aims to study the possibility of increasing the recovery factor and to optimize the cEOR injection and production parameters for a well pair in a sector of Heglig main oilfield.

An ASP model was studied using a computer simulation software (computer modeling group CMG).

The optimization of the ASP flooding increased the cumulative oil production by 0.482 MMbbl and, decreased the cumulative water production by 66.3 MMbbl .

الخلاصة

إن الطرق الكيميائية للاستخلاص يمكنها أن تزيد معامل الاستخلاص للعديد من حقول النفط ، ويعتبر حقل هجليج من الحقول التي يمكن زيادة معامل الاستخلاص لها بتنفيذ هذه الطرق، ولكن لم تجرى دراسة من قبل للتوصل للمعايير المثالية للحقن والإنتاج باستخدام الطريقة الكيميائية (ASP) في بئرين لهذا الحقل.

يقع الحقل في وسط وجنوب شرق تكتل 2B في حوض المجلد ، وهو من أكبر حقول النفط في السودان ، وظل ينتج الزيت منذ العام ١٩٩٩ م ، وتشير التقارير إلى أن إنتاج الحقل بلغ ذروته في العام ٢٠٠٦ م ، ثم أخذ ينقص منذئذٍ. يتكون الحقل من سلسلة طبقات حجر رملي كبيرة تفصل بينها طبقات طينية.

إن أكبر المشاكل التي ووجهت في السودان بسبب الماء المنتج ووجهت في هذا الحقل، وقد وصلت نسبة الماء إلى ٩٥% ، وتهدف هذه الدراسة لدراسة إمكانية زيادة معامل الاستخلاص، وللتوصل للمعايير المثالية للحقن والإنتاج بالطريق الكيميائية (ASP) لنموذج بئرين في مقطع من حقل هجليج الرئيسي.

دُرس نموذج غمر الـ (ASP) باستخدام برنامج تمثيل حاسوبي وهو برنامج Computer Modeling Group CMG.

تطبيق الحقن الكيميائي المثالي أدى إلى زيادة مقدارها ٠,٤٨٢ مليون برميل من الزيت المنتج، وإلى نقصان مقداره ٦٦,٣ مليون برميل من الماء المنتج.

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Chapter 1 Introduction

1.1 General Introduction

1.1.1 Oil Recovery Mechanisms

The term recovery refers to the total volume of hydrocarbons that has been or is anticipated to be produced from a well or field. In other words recoverable oil is the percentage of hydrocarbons that can be recovered from the formation under planned production methods. Often depends strongly on the revenue received from the oil and the operating cost.

The oil recovery methods fall mainly into three categories, depending on the reservoir conditions (i.e. Pressure, Drawdown, Permeability, ... etc.).

- Primary recovery.
- Secondary recover.
- Tertiary recovery (Enhanced Oil Recovery).

1.1.1.1 Primary Recovery:

The amount of the reserves recovered by primary production (in the first stage of oil production) i.e., without injected fluid pressure support, in which natural reservoir drives are used to recover oil, although some form of artificial lift may be required to exploit declining reservoir drives.

Oil can be recovered from the pore spaces of a reservoir rock by expansion or only to the extent that the volume originally occupied by the oil is invaded or occupied in some way. There are several ways in which oil can be produced from a reservoir, and these may be termed mechanisms or drives, and where one replacement mechanism is dominant, the reservoir may be said to be operating under a particular

drive. The analysis of drive mechanisms using a method of material balance follows the general form described by Schilthuis.

Possible sources of replacement for produced fluids are:

- a) Expansion of undersaturated oil above the bubble-point.
- b) The release of gas from solution in the oil at and below the bubble-point.
- c) Invasion of the original oil-bearing reservoir by gas from a free gas cap.
- d) Invasion of the original oil-bearing reservoir by water from an adjacent or underlying aquifer.

All replacement processes involve a reduction in pressure in the original oil zone, although pressure drops may be small if gas caps are large, and aquifers large and permeable, and pressures may stabilize at constant or declining reservoir offtake rates under favorable circumstances. The compressibility of oil, rock and connate water is generally relatively small, so that pressures in undersaturated oil reservoirs will fall rapidly to the bubble-point if there is no aquifer to provide water drive. As a result, these expansion mechanisms are not usually considered separately, and the three principal categories of reservoir drive are:

- Solution gas drive (or depletion drive) reservoirs.
- Gas cap expansion drive reservoirs.
- water drive reservoirs.

Frequently two or all three mechanisms (together with rock and connate water expansion) may occur simultaneously and result in a combination drive.

Some of the primary drive mechanisms are:

Water Influx:

Many reservoirs are bounded on a portion or all of their peripheries by water bearing rocks called aquifers. The aquifer may be so large compared with the reservoir they adjoin as to appear infinite for all practical purposes and they may range down to those so small as to be negligible in their effect on reservoir performance.

Solution Gas Drive :

They are forms of primary drive that exist as a result of the expansion of gases due to pressure depletion, percentage of oil that can be recovered 5 – 25%.

Gas Cap Drive :

This is the one of the most efficient of primary drives that is provided with gas cap i.e. accumulation of gas over oil column. It is characterized by slow pressure decline. Percentage of Oil recovery: 10 – 35%.

Gravity Drainage Drive :

This is one of the least efficient primary drives and it commonly exists in reservoirs that has sloppy configuration.

Expansion / Compaction:

Rock and connate water expansion drive that result from the expansion of rock matrix and the compaction of pore volume. Ultimate recovery: 1 – 5%.

1.1.1.2 Secondary Recovery:

The use of water flooding or gas injection to maintain formation pressure during primary production and to reduce the rate of decline of the original reservoir drive. When this is done such that average reservoir pressure is held constant, i.e. reservoir volumetric rate of production is equal to reservoir volumetric rate of fluid replacement, then the process is known as pressure maintenance. The level of pressure maintenance in oil

production is usually just above bubble-point pressure such that injection costs are minimized. Since production rate is also dependent on reservoir pressure gradient, then the choice of pressure maintenance level will also include rate consideration. In order to provide the capability for natural flow to surface under high water cut, the selection of pressure maintenance level might be determined from simple diagrammatic correlation. When the reservoir condition volumetric rate of fluid displacement is equal to the reservoir condition volumetric rate of production, the technique is known as complete voidage replacement. Nowadays, often initiated at or near the beginning of production, which involves adding external energy but without any fundamental changes to the physical properties of the fluids. This energy is added by either water or gas injection. In secondary recovery an appreciable amount of oil can still be trapped in the pores of the reservoir rock by capillary forces or in areas bypassed by the displaced fluid. Reservoir heterogeneity in the form of permeability changes is the main cause of capillary entrapment and bypassing, as the displacing fluid does not pass through areas of differing permeability evenly, resulting in some areas not being swept.

Water Injection:

Secondary recovery requires the injection to take place through one set of wells (the injectors) and the oil to be produced from others (the producers). The quantities injected attempt to keep the reservoir pressure high (pressure maintenance) and maintain economic production rates. Under residual conditions the stock tank oil left in place is S_{or}/B_o , and the smaller the factor is, the greater will be the oil recovery, i.e. B_o as large as possible (near bubble point) and the residual oil saturation, S_{or} small. At the bubble point, the hydrocarbon thermodynamics dictate that the oil will have its lowest viscosity and largest formation volume factor, so that the least oil (converted to stock tank conditions) will be left in the

reservoir and the most oil will be displaced under smallest pressure gradients. Also keeping the reservoir pressure at about that of the bubble point ensures that no gas blocks the pores. In the past, secondary recovery was often adopted late in the life of a field, when primary production by natural depletion was ending. Reservoir pressure maintenance by water injection can avoid the problems associated with solution gas drives of declining well production rates and increasing gas-oil ratios as reservoir pressure drops.

Gas Injection:

Oil recovery by water injection can be remarkably effective but much higher recoveries may, in theory and from observations of laboratory tests, be reached by immiscible or miscible gas injection, alone or in combination with water. This is achieved through reduction of microscopic residual oil saturation and/or the stabilization of the displacement of gravity forces. Gas injection is currently usually only applied to reservoirs which have a gas cap or have a large angle of dip, where the gas drive can use the effects of gravity.

1.1.1.3 Tertiary Recovery (Enhanced Oil Recovery):

Enhanced Oil Recovery (EOR) produces a portion of the oil unrecoverable by primary recovery methods. To store formation pressure and fluid flow to a substantial portion of a reservoir, fluid or heat is introduced through injection wells located in rock that has fluid communication with production wells. It is the use of certain recovery methods that not only restore formation pressure, but also improve oil displacement or fluid flow in the reservoir. These methods may include chemical flooding, gas injection, microbial injection, and thermal recovery (which includes cyclic steam, steam flooding, and fire flooding).

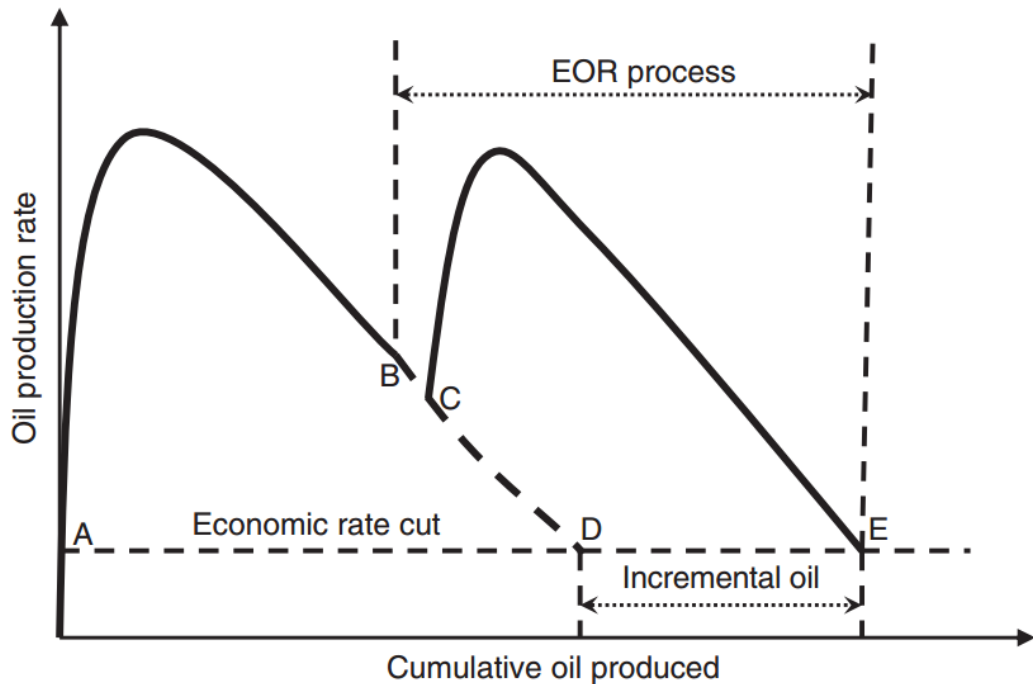


fig.1.1: Incremental oil recovery from an EOR process (Sheng 2010)

It is a generic term for techniques for increasing the amount of crude oil that can be extracted from an oil field. Using EOR, 30-60 %, or more, of the reservoir's original oil can be extracted compared with 20-40% using primary and secondary recovery. Enhanced oil recovery is also called improved oil recovery or tertiary recovery (as opposed to primary and secondary recovery). (OSE, A. T., 2011).

Chemical Enhanced Oil Recovery (cEOR)

chemical enhanced oil recovery (cEOR) is a type of EOR where the recovery enhancement is achieved by injecting chemical substances into the reservoir.

cEOR Methodology

The injection of various chemicals, usually as dilute solutions, have been used to aid mobility and the reduction in surface tension. Injection of alkaline or caustic solutions into reservoirs with oil that have organic acids naturally occurring in the oil will result in the production of soap

that may lower the interfacial tension enough to increase production. Injection of a dilute solution of a water-soluble polymer to increase the viscosity of the injected water can increase the amount of oil recovered in some formations. Dilute solutions of surfactants such as petroleum sulfonates or biosurfactants such as rhamnolipids may be injected to lower the interfacial tension or capillary pressure that impedes oil droplets from moving through a reservoir. Special formulations of oil, water and surfactant, microemulsions, can be particularly effective in this. Application of these methods is usually limited by the cost of the chemicals and their adsorption and loss onto the rock of the oil containing formation. In all of these methods the chemicals are injected into several wells and the production occurs in other nearby wells.

reduction of interfacial tension, spontaneous emulsification and wettability changes. The oil can then be more easily moved through the reservoir to production wells.

As in the two preceding methods, a polymer-thickened water solution process is introduced after the chemicals are injected to help obtain a more uniform movement or "sweep" through the reservoir. Fresh water is then injected behind the polymer solution to prevent contamination from the final drive water which may be salty or otherwise incompatible with the chemicals.

Alkaline flooding is usually more efficient if the acid content of the reservoir oil is relatively high. A new modification to the process is the addition of surfactant and polymer to the alkali, giving rise to an alkaline-surfactant-polymer (ASP) EOR method .

This method has shown to be an effective, less costly form of micellar-polymer flooding. (SPEIGHT, J. G., 2016).

1.2 Problem Statement:

Heglig oilfield holds large amount of STOIIP (577.95 MMSTB), but with low recovery factor (22.2 %) , and a high water cut (94.24 %) .as per previous studies, A proper chemical enhancement method is recommended. Designing of an ASP Flooding model in a well pair will be conducted to improve the recovery factor for this unit.

1.3 Objectives of the Study:

- To study the possibility to increase the recovery factor for Heglig.
- To Design an ASP Flooding model in a well pair in Heglig.
- To propose optimum chemical injection parameter.
- To propose optimum production parameter.

1.4 Introduction to the Case Study

Previous screening of EOR methods for Sudanese oil fields show that Heglig Main oil field is suitable candidate for cEOR operation; the Stock Tank Original Oil in Place (STOOIP) for this field is about 577.95 MMSTB where only 22.2 % was produced through naturally depletion.

The Greater Heglig Oilfield is located in the southeast and middle of Block 2B, Muglad Basin. The oilfield consists of 8 major fields, namely Heglig, Toma, El Bakh, El Ful, Laloba, Kanga, Barki and Simbir East. The average distance between the fields is about 3 to 5 km; this study will focus on Heglig Main field mainly because its STOIP reaches as high as 577.95 MMSTB, which is 63.2 % of the total STOIP of Greater Heglig. (29th DTR, GNPOC, 2012)

Heglig Main started production in June 1999; the main reservoirs are Aradeiba Main, Bentiu 1, Bentiu 2 and Bentiu 3, the drive mechanism is bottom and edge water with moderate to strong aquifer strength, the critical challenges of development are the high water cut and most of the remaining oil is located at the lower quality reservoirs, the current depletion strategy is adopting selective interval for the new infill wells whereas conducting sidetrack or workover for the existing wells, the previous studies in screening of EOR methods for the Sudanese oil fields 3 show that Heglig main oil field (B1a) is suitable candidate for EOR Chemical methods (ODIN, Norway, 2011) The figure below illustrates the Structure Map of Heglig Main-Bentiu-1 formation.

As per December 2012, there are total 70 producers and 5 suspended wells, i.e. by reservoir - Aradeiba Main (4 wells), Bentiu 1 (47 wells), Bentiu 2 (4 wells), and Bentiu 3 (14 wells including 8 commingle wells); the field performance is summarized in the table below:

Table 1.1:Heglig Main Performance Data (29th DTR, GNPOC, 2012).

Liquid Rate, STB/Day	Oil Rate, STB/Day	Water Cut, %	Cumulative Oil, MMBBL
203053.25	11695.29	94.24	126.469

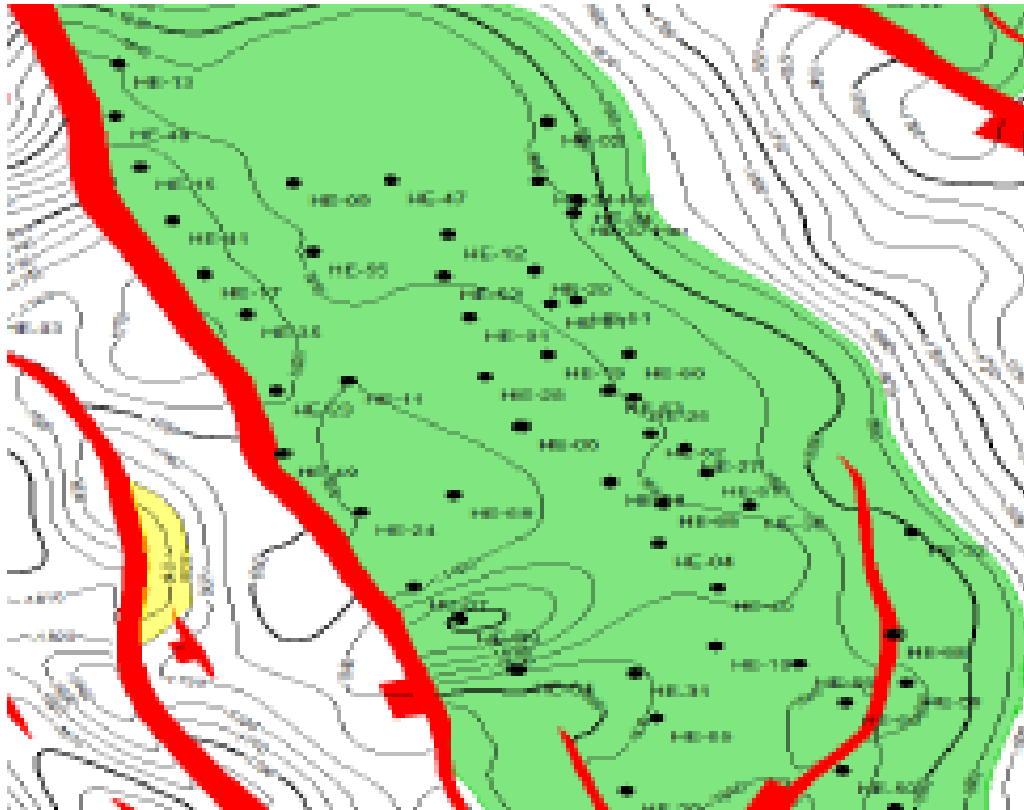


Fig.1.2: Structure Map of Heglig Main-Bentiu-1(Husham 2015)

Chapter 2 Theoretical Background and Literature Review

2.1 Theoretical Background

2.1.1 Oil recovery processes:

Oil reservoirs run through series of production stages classified as primary (natural drive mechanism), secondary and tertiary recovery techniques. These stages designate production from a reservoir in a sequential pattern with different recovery efficiencies over time Oil recovery is predominantly influenced by capillary number (Nc) at the microscopic scale and mobility ratio (M) at the macroscopic scale. Capillary number denotes the ratio of viscous forces to interfacial tension (IFT) forces , Eq. (2.1) (Green 1998)

$$Nc = V\mu / \sigma \quad (2.1)$$

where Nc represents capillary number; V is Darcy's velocity; μ is viscosity of displacing fluid; and σ is the interfacial tension (IFT) between the displaced and the displacing fluid. It has been experimentally shown that an increase in capillary number (from a typical value around 10^{-7}) decreases residual oil saturation. This can be accomplished by an increase in the velocity of the injected fluid (i.e. Darcy's velocity, V) and/or viscosity of the displacing fluid (μ) and/or a reduction in IFT (σ). However, substantial increase in capillary number is required, thus, surfactant or alkaline flooding is recommended as the most feasible option for microscale displacement. Mobility ratio (M) is the ratio of the mobility of the displacing fluid to the mobility of the displaced fluid Eq. (2.2) (Thomas, 2008).

$$M = \lambda_{ing} / \lambda_{ed} \quad (2.2)$$

And

$$\lambda = k / \mu \quad (2.3)$$

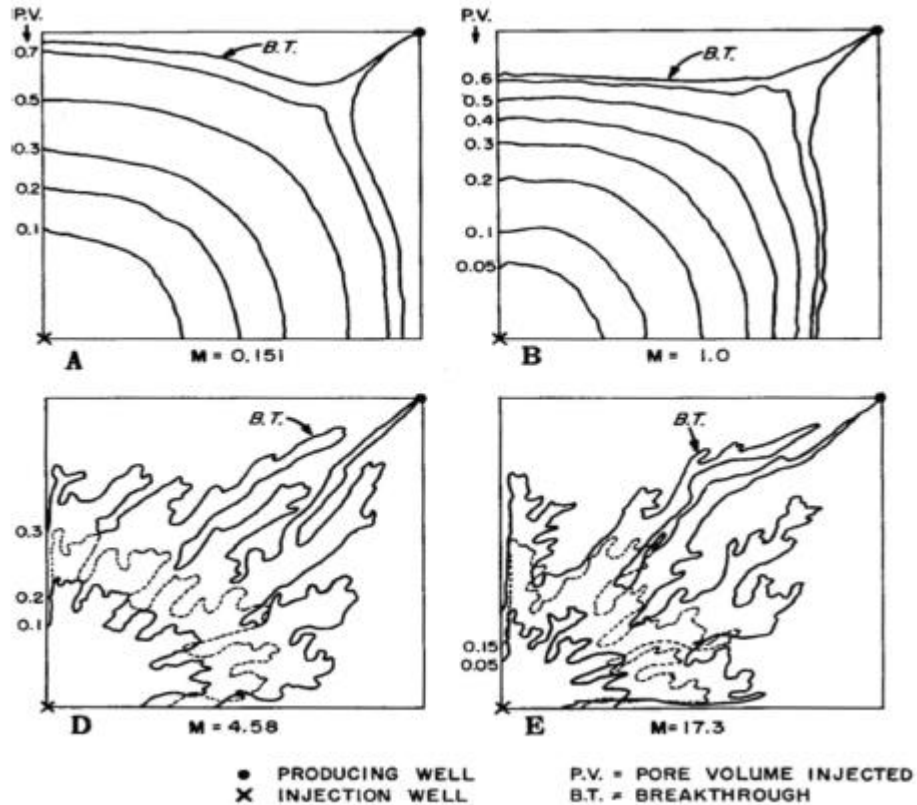


Figure 2.1: Displacement fronts

where M is mobility ratio; λ_{ing} is displacing fluid mobility; λ_{ed} is displaced fluid mobility; k is effective permeability (m^2); and μ is fluid viscosity (Pa s). The stability of displacement, which is of key importance for macroscopic displacement efficiency, is ultimately determined by the mobility ratio (M). If M is less than or equal to 1 ($M \leq 1$), it is considered favourable, and displacement efficiency increases (Figure 2.1); however, if $M > 1$, the mobility ratio is seen as unfavorable and residual oil will be inefficiently displaced. during waterflooding for different mobility ratios and pore volumes injected until breakthrough . (Romero 2016)

Oil recovery efficiency is greatly dependent on the microscopic and macroscopic displacement efficiency. Generally, microscopic displacement efficiency measures the extent to which the displacing fluid mobilises the residual oil once in contact with the oil, and it is greatly controlled by factors such as rock wettability, relative permeability, IFT and capillary pressure; note that a decrease in oil viscosity, IFT or capillary pressure of the displacing fluid can increase the microscopic efficiency.

Macroscopic displacement efficiency, otherwise known as volumetric sweep efficiency, measures the extent to which the displacing fluid is in contact with the oil-bearing parts of the reservoir (metre to hectometre scale, Eq. (2.4)), and it is influenced by the rock matrix heterogeneities and anisotropy, displacing and displaced fluid mobility ratio and injection and production well(s) positioning. The product of microscopic (E_d) and macroscopic (EV) displacement efficiency yields the overall displacement efficiency (E) of any oil recovery displacement process.

$$E = E_d E_v \quad (2.4)$$

and

$$E_v = E_i E_a \quad (2.5)$$

where E_i is the vertical sweep efficiency and E_a is the areal sweep efficiency.

Natural drive mechanisms recover oil during the initial or primary production stage of a reservoir by means of the natural energy present in the reservoir without the need of supplying any additional energy. These

natural mechanisms use the pressure difference between the reservoir and the producing well bottom. The total recoverable oil using this method is considered inefficient, as recovery is usually less than 25% of the original oil-in-place (OOIP).

Secondary recovery techniques are applied when the natural reservoir drive is depleted ineffectively and inadequately for augmenting production. This technique involves injection of either natural gas or water to stimulate oil wells and maintain reservoir pressure in the injection wells. The injected fluids act as an artificial drive to supplement the reservoir energy. Such fluids boost the flow of hydrocarbon towards the wellhead. If the injected fluid is water, the process is usually termed waterflooding; if the injected fluid is gas, the process usually involves pressure maintenance operations. Gas-cap expansion into oil columns (wells) displaces oil immiscibly due to volumetric sweep-out. Diverse methods are used for fluid injection into oil reservoirs to support the natural forces.

Recovery efficiencies in the secondary stage vary from 10 to 40% of the original oil-in-place. Other gas processes, whose mechanisms entail oil swelling and viscosity reduction, or favorable phase behavior, are enhanced oil recovery (EOR) processes. Tertiary recovery techniques otherwise called enhanced oil recovery (EOR) processes demonstrate enormous potential in recovering stranded oil trapped at the pore scale after primary and secondary recovery techniques by capillary pressure-driven snap-off, which leaves behind in the reservoir about one-third of OOIP. The stranded oil is often located in regions considered inaccessible. EOR methods can extract more than half of the total OOIP and significantly more than the primary and secondary recovery methods. Notably, the impact of EOR on oil production is colossal as an increase in recovery factor by only 1% can yield 70 billion barrels of conventional

oil reserves globally without the exploitation of unconventional resources. In comparison to primary and secondary recovery methods, EOR undeniably is a better alternative as its contributions to global oil production entails a more economically feasible process. (Romero 2016)

2.1.2: Enhanced oil recovery (EOR):

Improved oil recovery (IOR) is often erroneously used in place of enhanced oil recovery (EOR). IOR and EOR are two different concepts: IOR is a wider concept that embroils ultimate recovery of oil by any means. The EOR is mainly driven by the ability to recover more oil at an economically feasible production rate. The EOR can be described as a subset of IOR. EOR uses several processes and technologies to increase or uphold recovery from existing fields. These processes often involve the injection of fluid(s) and most recently microbes into a reservoir. These fluids, in turn, supplement the reservoir natural energy for effective oil displacement into the producing well thus yielding an interaction between injected fluid and the reservoir rock/oil system that creates a favorable condition for oil recovery. The key drive for EOR spins around its capability of turning residual cumulative oil into reserves with oil (million barrels) produced from existing fields, which is achieved by overcoming the physical forces confining hydrocarbons underground

2.1.2.1: Chemical EOR techniques (CEOR)

In chemical EOR (CEOR) techniques, oil is recovered through the injection of chemicals. CEOR is predominantly suitable for heavily depleted and flooded formations (i.e. mature reservoirs). Typical chemicals are polymers, surfactants, alkalis and formulated mixtures thereof. The efficiency of such formulations is normally screened in laboratory studies and each chemical has different effects on oil

production. For example, the application of surfactants or alkali or its mixtures can substantially reduce the interfacial tension between brine and oil; significantly improving the microscopic sweep efficiency at the pore scale. Mobility ratios can be considerably improved by adding polymers to the injected water. The addition of polymer to the injection brine increases the viscosity of the aqueous phase, which leads to an improved macroscopic displacement, as water under-riding is lessened. The addition of surfactants improves the microscopic displacement efficiency through: (a) the reduction of the oil-water interfacial tension and (b) the production of oil-water emulsions, which mobilises residual oil. The addition of alkalis induces the *in situ* formation of natural surfactants by reacting with the acidic components contained in the crude oil (generally heavy oils). These natural surfactants function in the reservoir in the same fashion as synthetic surfactants. (Adasania A. A., Bai B. (2011))

Evolution of chemical EOR

In the last few years, CEOR has been undergoing a rebirth. Since the 1960s, polymer flooding has been globally the most widely used of the three types of CEOR techniques. CEOR has experienced significant chemical developments since its first applications in the 1960s and 1970s. For example, micellar flooding in the 1970s and 1980s was very effective in light and medium oil reservoirs, where CEOR processes applied micellar floodings at surfactant concentrations ranging from 2 to 12%. However, the concentrations of surfactant used have notably decreased to values ranging from 0.1 to 0.5%; while at the same time, micellar floodings at these low surfactant concentrations have demonstrated significantly increased efficiency. In the face of the current oil price instability, interest in surfactant for CEOR processes, have maintained a

constant growth trend. However, at present, the high cost of surfactants makes very difficult the economic justification for field applications of surfactant flooding.

Polymer flooding:

For several decades, hydrogel polymers have been used for mobility control. Likewise, polymers in combination with surfactants and alkalis have been applied over the years to improve both the microscopic and macroscopic sweep efficiency. In recent times, several new polymers for EOR have been developed such as synthetic polymers (i.e. polyacrylamide or PAM) (Figure 2.2), hydrolysed polyacrylamide (HPAM), biopolymers (i.e.xanthan gum) and superabsorbent polymer composite (SAPC).

Among these polymers, HPAM (Figure 2.2) remains the most effective and commonly used polymer for enhanced oil recovery.

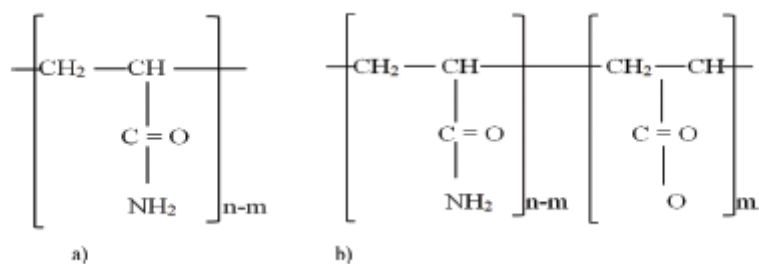


Fig 2.2: Structure of: (a) polyacrylamide (PAM), and (b) partially hydrolysed polyacrylamide (HPAM) (Romero 2016)

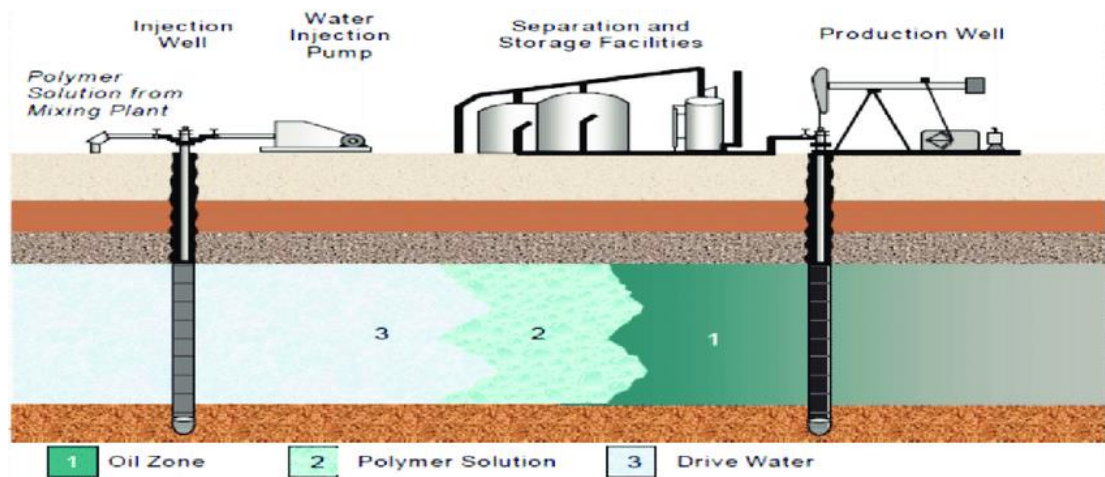


Fig 2.3 : Polymer flooding (ResearchGate 2018)

Process benefits.

Polymers are effective brine viscosifying agents and successfully reduced the effective permeability to brine (i.e. polymer retention). Overall, polymer flooding is a cost-effective EOR process.

Process limitations.

Some of the limitations of polymer flooding are their susceptibility of polymers to thermal (i.e. high temperature reservoirs), chemical (i.e. high salinity and hardness concentration in the injected and formation brine), mechanical and bacterial degradation. Some polymer systems are incompatible with the reservoir fluids and conditions (i.e. temperature). The application of polymer flooding in low permeability rocks may cause problems of injectivity and formation plugging.

Surfactant Flooding

Surfactants are amphiphilic in nature (hydrophobic and hydrophilic) and are soluble in water and organic solvents. Surfactants effectively reduce the interfacial tension (IFT) between oil and water (i.e. brine).

Four basic categories of surfactants exist: anionic, cationic, nonionic and zwitterionic.

In surfactant flooding applications, a dilute aqueous surfactant solution is injected into the reservoir. Mechanistically, the injected surfactant migrates to the oil-water interface reduces the interfacial tension (IFT) between oil and water and essentially increases the miscibility of these phases. To put this into perspective, in a typical waterflooding process, IFT is approximately 30 mN/m; the addition of small concentrations of surfactant (in the range of 0.1–5.0 wt%) to the injected water can significantly reduce IFT to values of 0.01 mN/m or lower. The critical micelle concentration (CMC), phase behavior and oil solubilisation ratio are key parameters for the characterisation of the efficiency of the surfactant formulation. For effective oil displacement:

- Dilute aqueous surfactant solutions are injected in slugs.
- The injected slugs must attain ultra-low IFT.
- This leads to the mobilisation of the residual oil and creation of oil banks, which allows the continuous phase flow of oil and water. (Romero 2016)

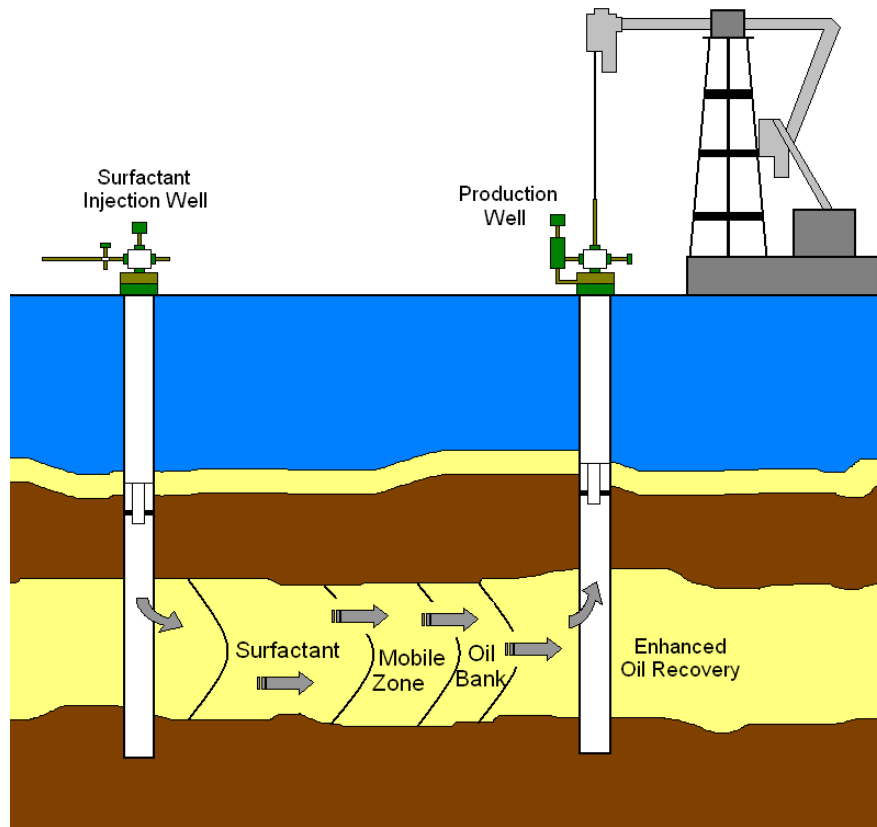


Fig 2.4 : surfactant flooding (ResearchGate 2018)

Process Benefits.

Effective reduction of the interfacial tension between brine and water that significantly enhances the microscopic sweep efficiency.

Process Limitations.

The achievement of ultra-low IFT for effective residual oil mobilisation is a complex process. Large amounts of surfactants are required to achieve substantial oil recovery. The viscosity of the surfactant formulation is often lower than that the viscosity of the oil, thus, to augment the viscosity of the surfactant slug, the addition of polymers to the surfactant formulation is required. The high cost of surfactants makes its deployment in the field highly dependent on oil price.

Alkaline flooding

Alkaline flooding involves the injection of an aqueous solution of alkaline chemical such as sodium hydroxide, sodium carbonate or sodium orthosilicate in a slug form. The most commonly used alkaline chemical is sodium hydroxide.

During alkaline flooding, the alkaline solution and organic acids present in the crude oil react to form natural surfactants in situ, which cause the reduction of IFT between the brine and oil. Natural surfactants induce the formation of oil and water emulsions and wettability alteration of the reservoir rock. All these physicochemical interactions occur at the oil-water rock interfaces, which invariably improves oil recovery.

Process Benefits.

Alkaline flooding shows potential for heavy oil recovery in thin formations. This process promotes effective IFT reduction and crude oil emulsification. Overall, alkaline flooding is characterized for low operational costs.

Process limitations.

Scale formation is a serious issue during alkaline flooding. Furthermore, the low viscosity of the alkaline solution is associated with the occurrence of unfavorable fingering and poor volumetric sweep efficiency.

Surfactant-polymer (SP) flooding

In surfactant-polymer flooding, separate surfactant and polymer slugs are injected into the reservoir. The alternate injections of surfactant and polymer slugs have the potential to sweep larger reservoir volumes and to increase oil displacement efficiency. The mobility control is

established during SP flooding by injecting the chemical slugs according to the following injection scheme: surfactant slug, polymer slug, polymer buffer (to protect the integrity of the polymer slug) and chase water.

Accurate formulation of the surfactant-polymer (SP) mixture can promote capillary number increase (due to the presence of surfactants through IFT reduction) and reduction in mobility ratio. However, an incompatible SP formulation can cause surfactant and polymer phase separation even when oil is not present [103]. Two essential factors for consideration during SP flooding are: (a) IFT reduction and (b) viscosity increase . In addition, the effective permeability to water is reduced due to polymer retention in the formation rock. Therefore, an overall improvement of mobility ratio and sweep efficiency is achieved rendering incremental oil recovery.

Process benefits.

Accurate SP formulation can achieve ultra-low oil-brine IFT, which promotes effective displacement of residual oil saturation.

Process limitations.

The main limitation of the SP flooding process is chemical incompatibility among the additives and brine (injection and formation brine).

Alkaline-surfactant-polymer (ASP) flooding

ASP flooding uses alkali-surfactant-polymer cocktails for further improvement of oil recovery efficiency. The key reasons for the

combination of the three chemicals are IFT reduction and mobility ratio improvement. Alkali decreases surfactant adsorption onto rock surface through an increase of the negative charge density at the rock surface yielding a more water-wet surface. Surfactant decreases the IFT between oil and brine, which promotes oil mobilisation and oil bank formation, whereas polymer offers mobility control. The amount of chemical consumed per unit volume of oil produced during ASP flooding is usually low when the three chemical slugs (alkaline, surfactant and polymer) are injected in sequence or as a single slug .

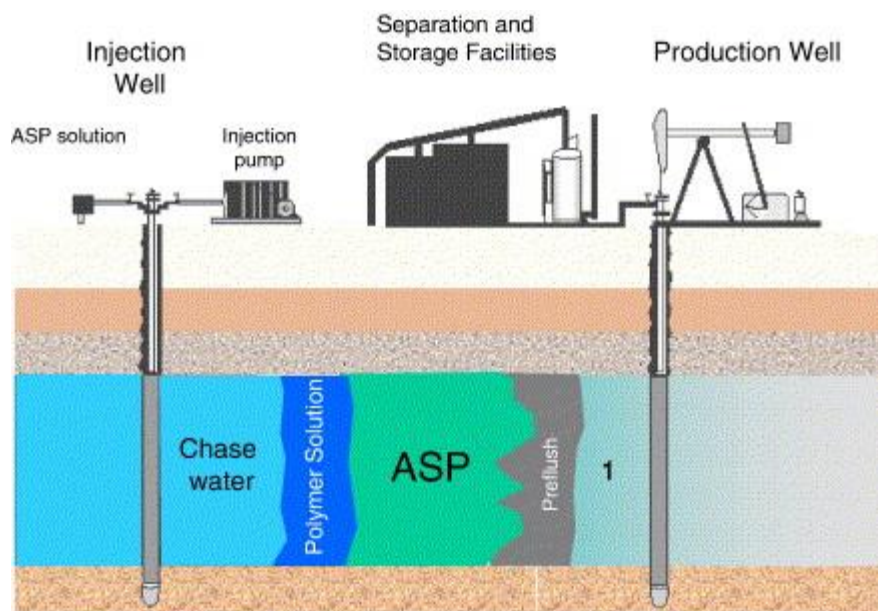


Fig 2.5: ASP Flooding (Zerpa 2005)

Process benefits.

ASP is a cost-effective process. The synergistic effects of the ASP mixture make this process attractive for EOR applications.

Process limitations.

Some of the limitations of the ASP process are related to issues with chemical separation, emulsions instability and scale formation that could make the process complex. (Romero 2016)

Displacement Mechanisms

In ASP flooding, when surfactant mixes with alkali, crude oil, and formation water, emulsification can occur. The important mechanisms are the alkali emulsification and soap generation owing to its reaction with the crude oil. Surfactant makes emulsions stable through reduced IFT, increases interface (film) strength, and generates charge at the interface. More importantly, added surfactant makes the low IFT salinity range wider because of the synergism with in situ generated soap. Polymer increases water viscosity. In turn, higher external viscosity can reduce the diffusion of droplets, resulting in less probability of coalescence. Thus, emulsion stability is improved. When the number of dispersed droplets increases, emulsion viscosity is increased and stability is improved.(Sheng 2010)

2.2 Literature Review

2.2.1 Case Study Worldwide:

Shutang et al., (1996) studied the effect of ASP flood on the performance of the west central suertu Daqing oil field. They conducted core flood analysis and numerical simulation followed by actual performance test on the pilot area. The ASP flooding increased the sweep efficiency, oil production, oil rate, and decreased water cut. And it was found that the incremental oil will exceed 20 % OOIP.

Barreau et al.,(1997) performed numerical simulation to study the effect of polymer adsorption on relative permeability and capillary pressure. The simulation results showed that the presence of the polymer will increase the residual water saturation (SOR) and capillary pressure. Also it showed that the polymer have a selective effect on relative permeability, it decreases the relative permeability to water as much as twice the reduction of the relative permeability to oil which is consistent with previous experiments.

Delshad, M., et al., (1998) conducted a Coreflood and a 3-D field-scale ASP simulations to predict the effect and to optimize the performance of Alkaline/Surfactant/Polymer flooding in Karamay oil field in China, it was found that an ASP flooding can result in 23.6% ROIP, and 663% Incremental oil recovery compared to waterflooding.

Jay Vargo, et al., (1999) discussed the performance and the factors which made Cambridge Minnelusa field ASP flood successful. The aim was to increase the amount of produced oil by reducing the water flood residual oil saturation. ASP injection implemented increased the oil cut

by 36% and the recovery by 27% OOIP. ASP flooding has produced 65% more oil compared to a water flood.

Werner Shinagel, et al., (2007) provided case study about application of surfactant in three wells located in the North Sea Gas field. All three wells succeeded in lifting the liquid with surfactant, two of them could be kept online longer comparing to without using surfactant. The other one's produced liquid was too much to be handled by the topside facilities. The surfactant treatment were highly successful in a way that exceeded expectations.

Hunky, R.M, et al., (2010) studied the effect of alkaline-surfactant flooding for the Pennsylvanian Warner sand in Western Missouri. Several surfactants and Alkaline have been. the AS flood showed an ability of reducing viscosity of the heavy oil from 18518 cp to 2.5 cp at 25 °C. Also it was found that the solution can alter the sand wettability from oil-wet sand to water-wet sand and achieve oil recovery of 11% from ROIP.

Ibrahim, Z., et al., (2006) investigated the feasibility of increasing oil recovery through chemical EOR processes for Malaysian oil fields. They conducted a laboratory evaluation processes on linear and radial cores. Several Chemical EOR processes investigation were made, among which were alkaline-surfactant, and alkaline-surfactant-polymer corefloods. The average recovery for AS corefloods was 14.6% OOIP, while that for ASP corefloods was 28.6% OOIP.

2.2.2 Case Study In Sudan:

Farog, et al., provided a case study about implementation of cEOR as a huff and puff, the goal was to improve oil recovery for heavy oil using chemical treatment (SEMAR) in Bamboo oil field in Block 2A Muglad Basin. From Imbibition test, the results showed that the oil recovery by using SEMAR is two times more than that by using Brine, and the Mix between SEMAR and Oil resulted in reducing Oil viscosity from 76 cp to nearly 2 cp .

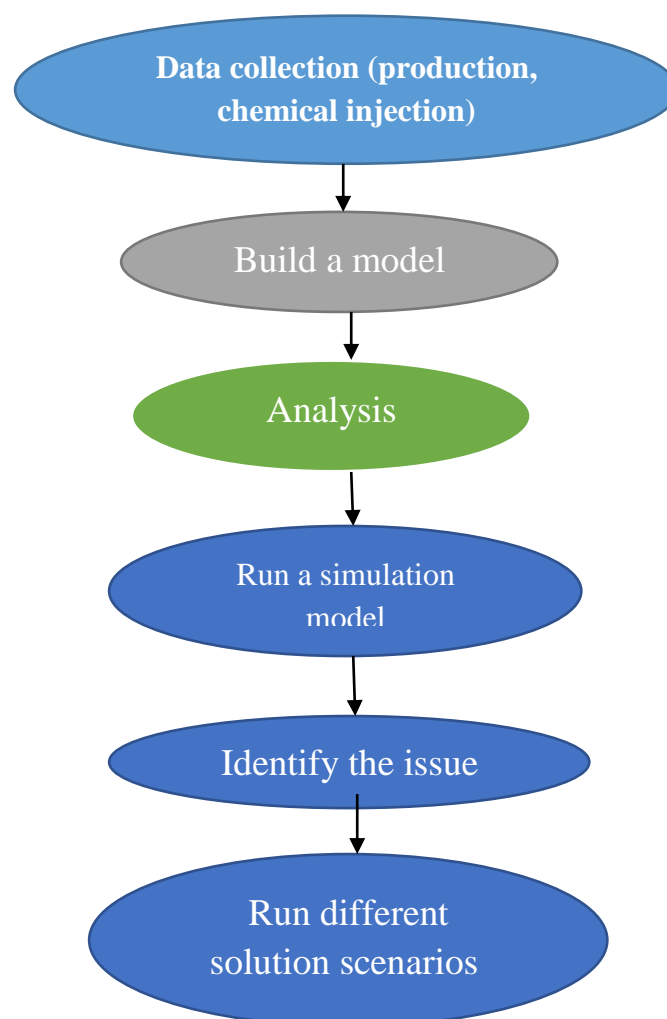
Husham A. Ali, Tagwa A. Musa, and Abe Doroudi (2015), Conducted a pilot design in Heglig Main Oil Field. The results show that a combination of 0.4wt% of Alkaline, 0.1wt% of Surfactant, and 0.1wt% of Polymer in an ASP flooding process can increase the recovery factor of Heglig main up to 43.54%

From research side, Optimization of cEOR for Heglig oilfield hasn't been implemented for a well pair. this study focuses on optimization of injection and production parameters for a well pair in a sector of Heglig main oilfield.

Chapter 3 Methodology

3.1 Introduction

The Geological data, reservoir data and production data of Heglig main Oilfield had been collected and used to analyze the effect of the ASP flooding in the field, and to design the optimum injection and production parameters, in order to increase the recovery factor. The Reservoir Properties (i.e. porosity, permeability, depth, initial formation pressure etc...) had been analyzed. All these analysis will be implemented and presented in steps in order to find the optimum flooding scenarios. The analysis steps are summarized in the chart below:



The study is a s implemented through computer simulation using CMG software .

3.2 Steps To Build A Simulation Model

To start building the model double click on Builder icon, a window will pop up that allows you to specify the proper simulator, the working units, the porosity type, and the simulation start date (figure 3.1)

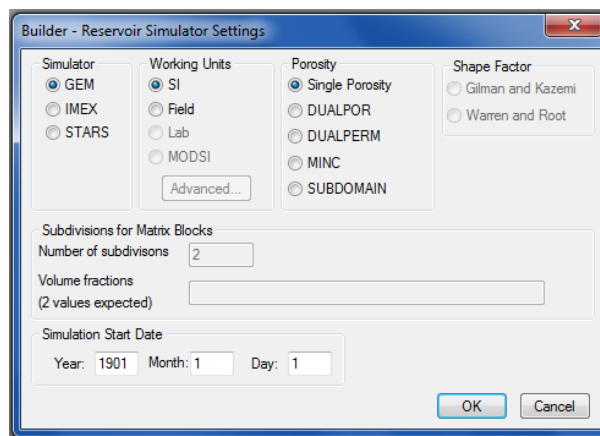


Figure 3.1:Reservoir Simulation Settings

To build an advanced model of recovery processes choose STARS and the proper specifications then click OK then OK in the next window Then the builder interface will appear (figure 3.2)

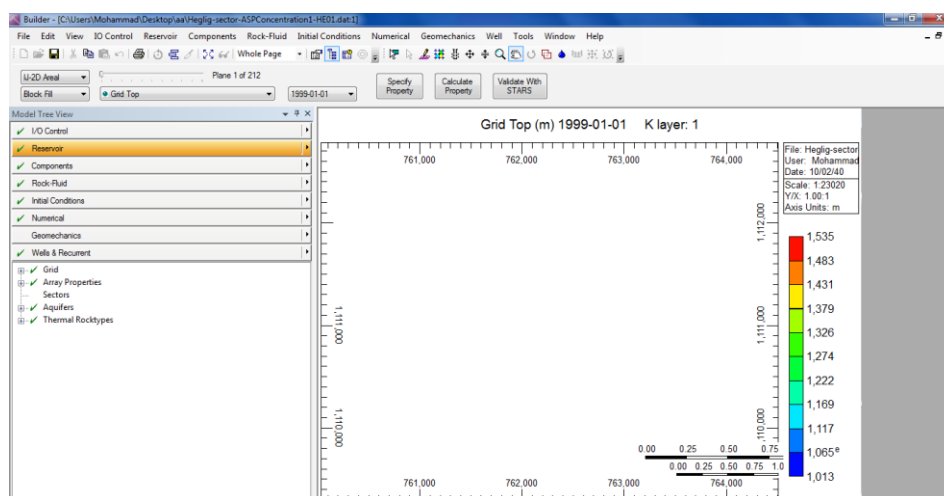


Fig 3.2: Builder interface

On the left side of the screen you can see the Model Tree View, this is where you can enter the model data

Creating the Simulation Grid (structural data)

To import a map Click on file then Open Map File, from reservoir list you can create the grid system (figure 3.3)

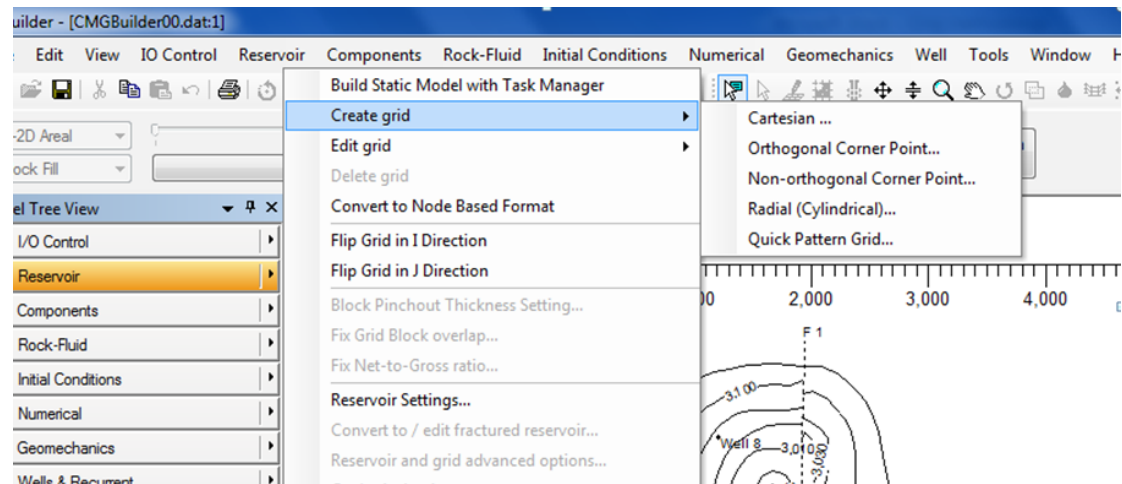


Fig 3.3: Grid selection

- From **components** you can Import the PVT data
- From **Rock-Fluid** you can specify the relative permeability and the rock property data
- From **Initial Conditions** you can create initial conditions
- From **Numerical** you can control the timestep
- From **wells & recurrent** you can specify the data related to the wells such as number of wells, location, trajectories,...etc

3.3 Steps to Build A Chemical Flooding Model

- From the tree view on the left side of the screen click on components then click on process wizard (figure 3.4)

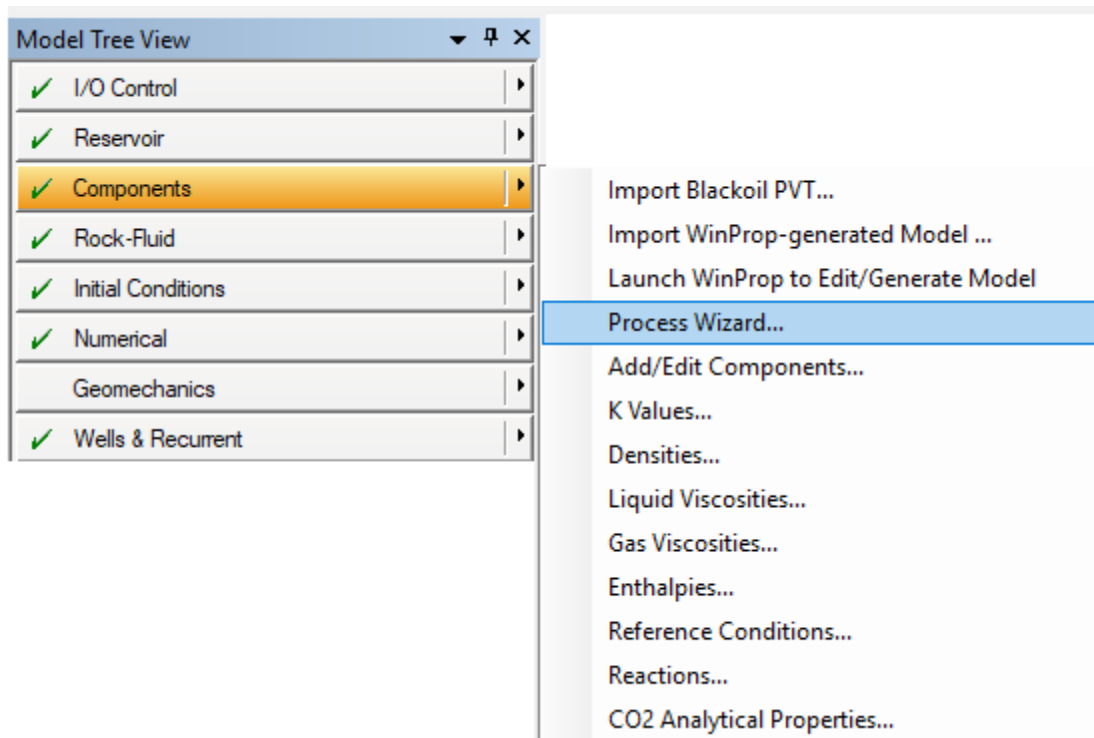


Fig.3.4: Opining Process wizard

In process wizard window, choose Alkaline, surfactant, foam, and/or polymer model (figure 3.5)

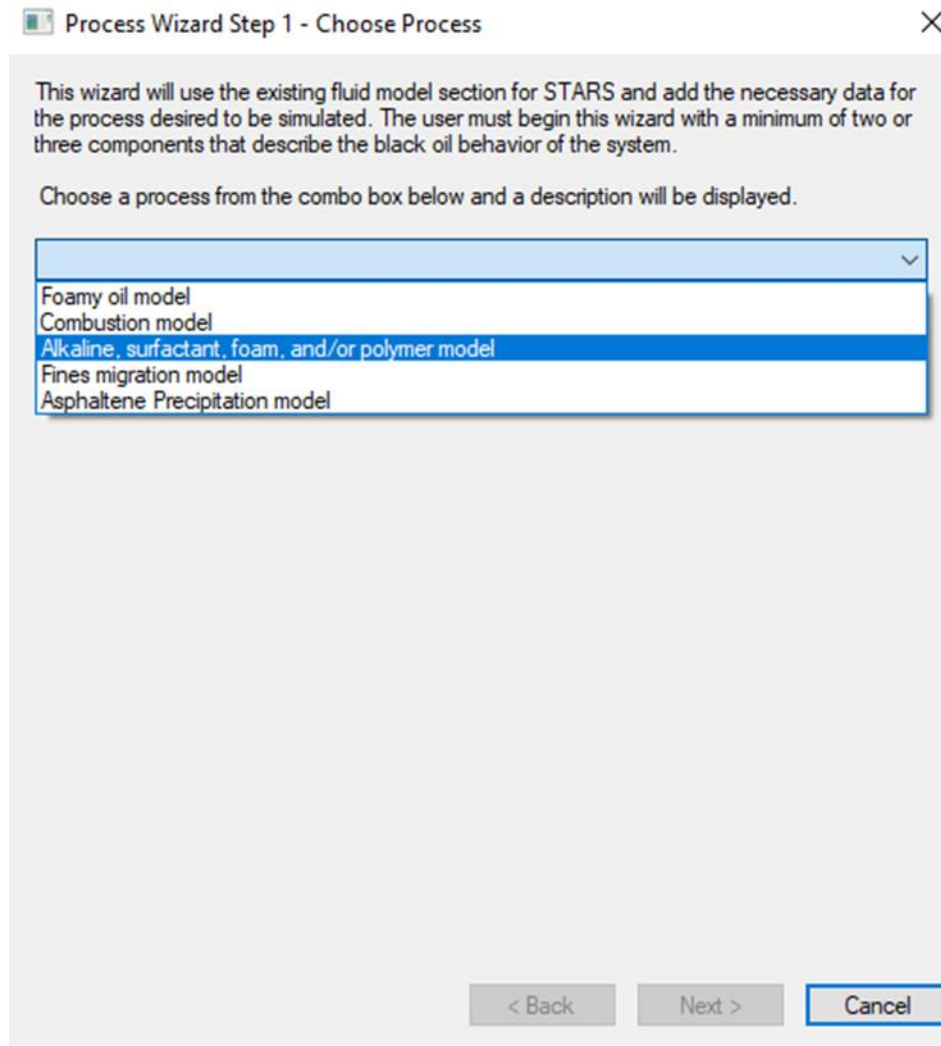


Fig.3.5: Process selection

- Click next

In flood model screen, select options for the selected model In Flood models screen choose alkaline, surfactant, polymer flood (add 3 components) then click next (figure 3.6)

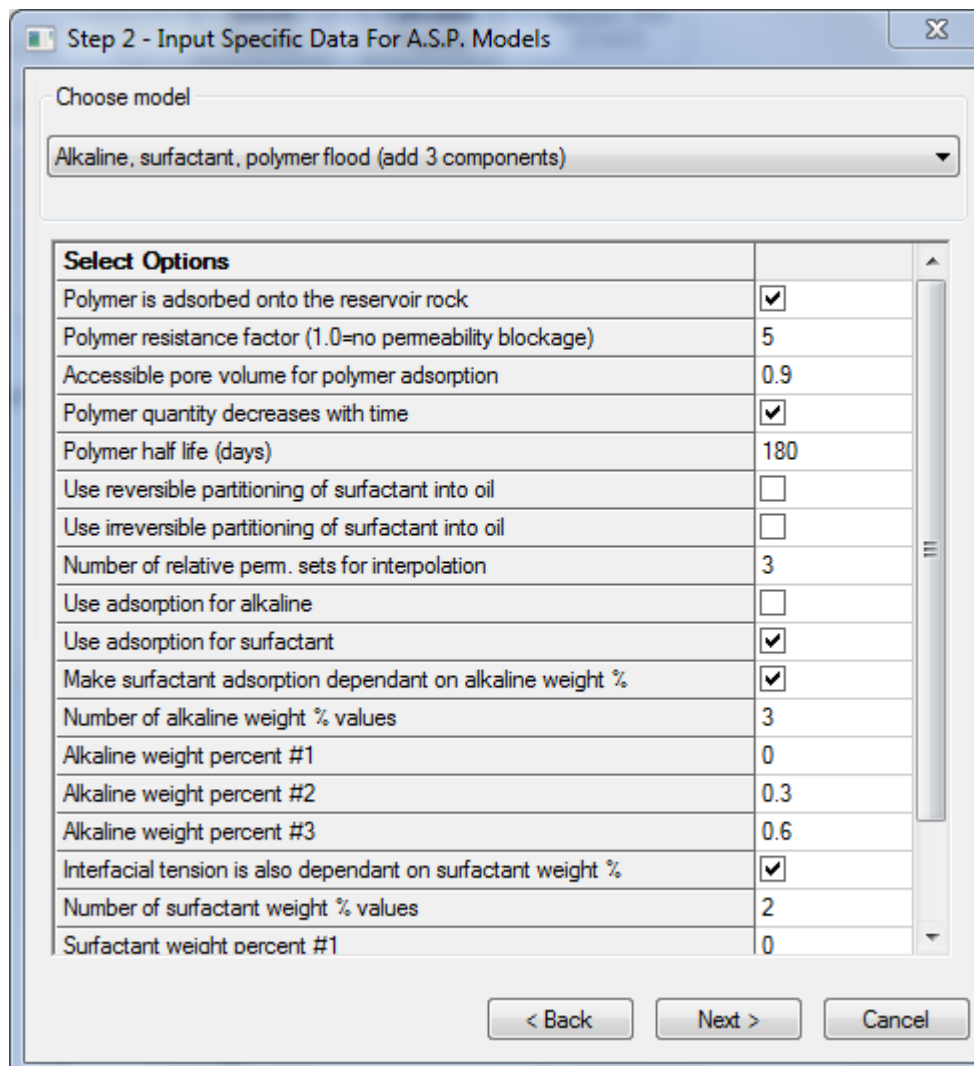


Fig.3.6: flood mode selection

In the next window add a new component if no components had been defined, or just select the components that had already been defined then click next (figure 3.7)

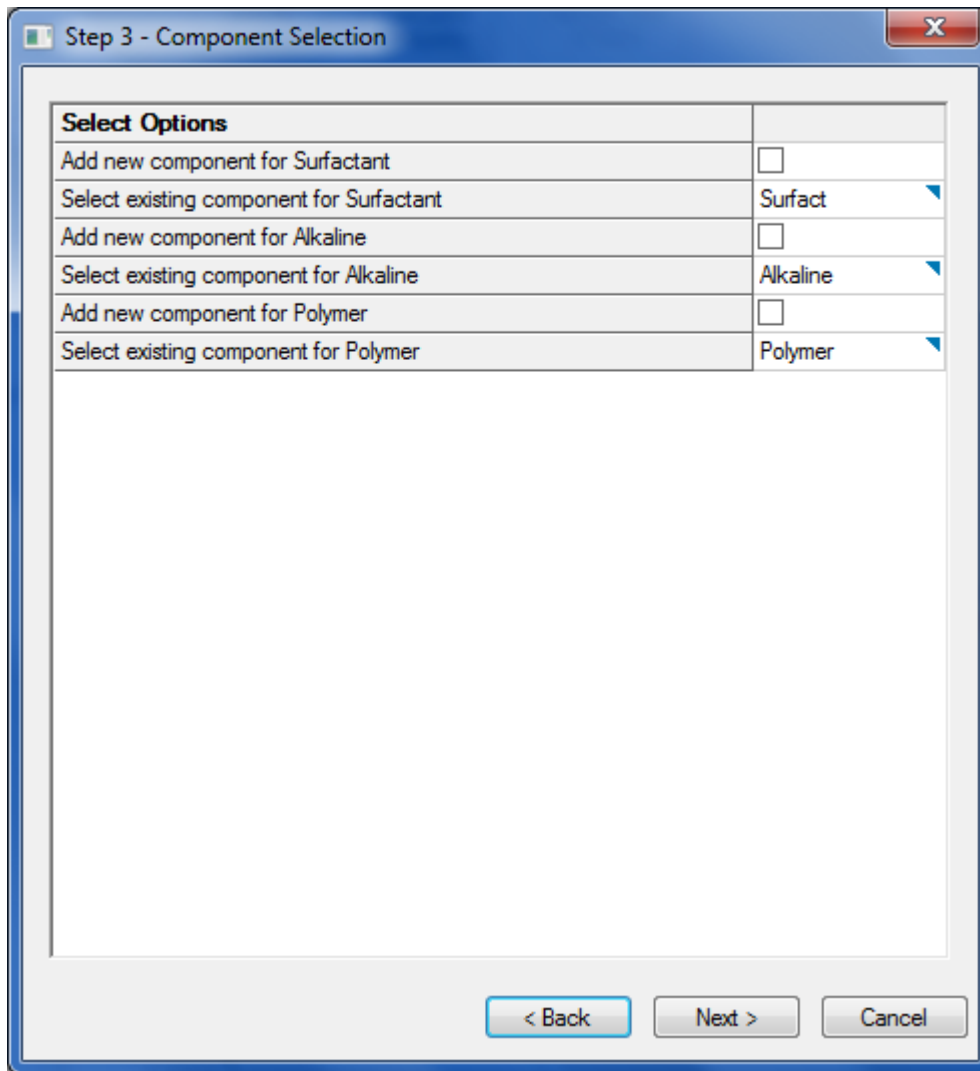


Fig.3.7: components selection

Set Rock Fluid Regions;

This is to select the region from which the relative permeability curves will be used for interpolation, choose rock fluid region number 1, then click next (figure 3.8)

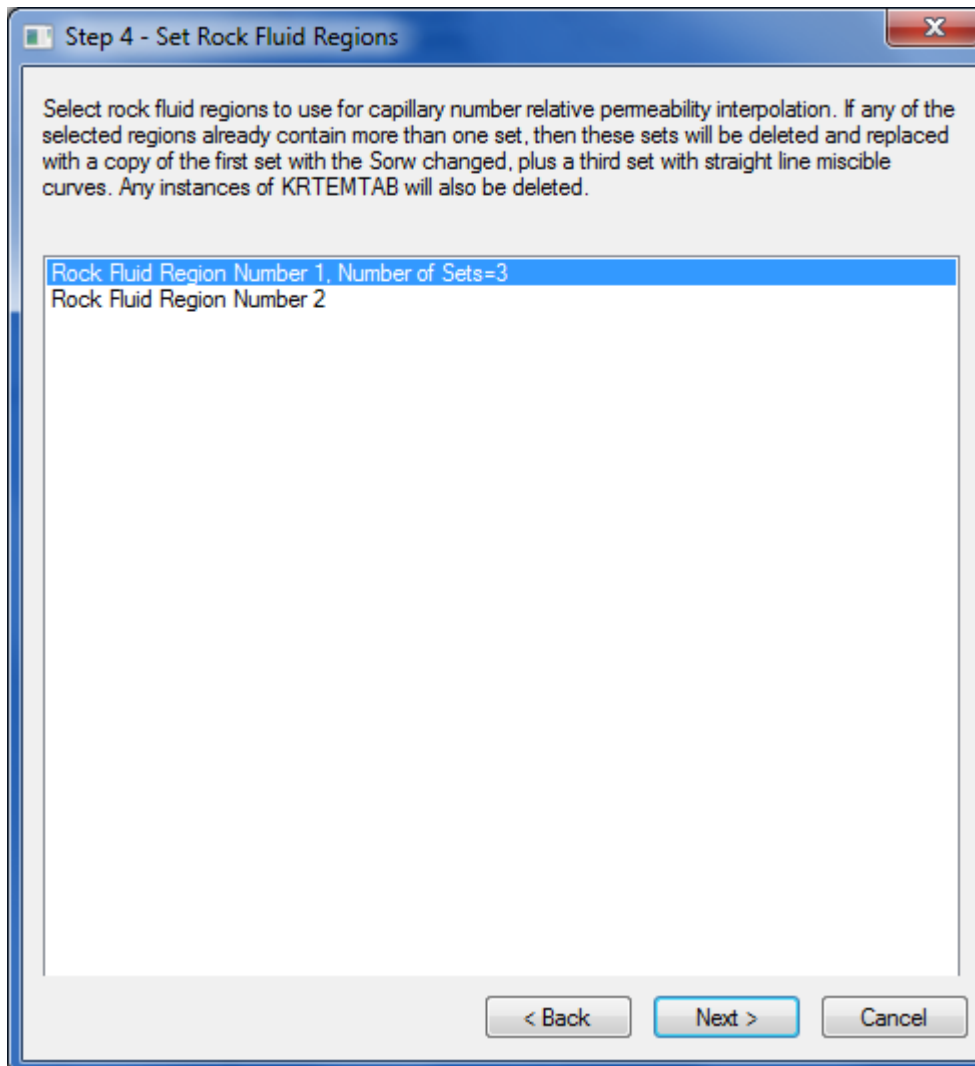


Fig. 3.8: Set Rock Fluid Regions

In The next window will set the weight % vs. Interfacial Tension table from the lab (figure 3.9)

Step 5 - Set Interfacial Tension Values

		Weight % Alkaline	IFT, (dyne/cm)
1	Surfactant wt. % = 0	0	23.4
2	Surfactant wt. % = 0	0.5	5.163
3	Surfactant wt. % = 0	0.75	4.356
4	Surfactant wt. % = 0	1	3.715
5	Surfactant wt. % = 0	1.25	4.102
6	Surfactant wt. % = 0	1.5	3.805
7	Surfactant wt. % = 0	1.75	3.521
8	Surfactant wt. % = 0	2	2.953
9	Surfactant wt. % = 0.05	0	0.17
10	Surfactant wt. % = 0.05	0.5	0.011
11	Surfactant wt. % = 0.05	0.75	0.005
12	Surfactant wt. % = 0.05	1	0.007
13	Surfactant wt. % = 0.05	1.25	0.007
14	Surfactant wt. % = 0.05	1.5	0.056
15	Surfactant wt. % = 0.05	1.75	0.097
16	Surfactant wt. % = 0.05	2	0.098

< Back Next > Cancel

Fig. 3.9: Set Interfacial Tension Values

In The next window set the weight % vs. Surfactant adsorption table from the lab, click next (figure 3.10)

Step 6 - Set Adsorption Values

Enter porosity of laboratory surfactant adsorption sample

		Weight % Surfactant	Surfactant Adsorption, m...
1	Alkaline weight %= 0	0	0
2	Alkaline weight %= 0	0.1	27.5
3	Alkaline weight %= 0.3	0	0
4	Alkaline weight %= 0.3	0.1	39.5
5	Alkaline weight %= 0.6	0	0
6	Alkaline weight %= 0.6	0.1	51

Enter porosity of laboratory polymer adsorption sample

	Weight % Polymer	Polymer Adsorption, mg/(100gm rock)
1	0	0
2	0.1	50

< Back Next > Cancel

Fig. 3.10: Set Adsorption Values

In The next window set the polymer property values from the lab, then click finish (figure 3.11)

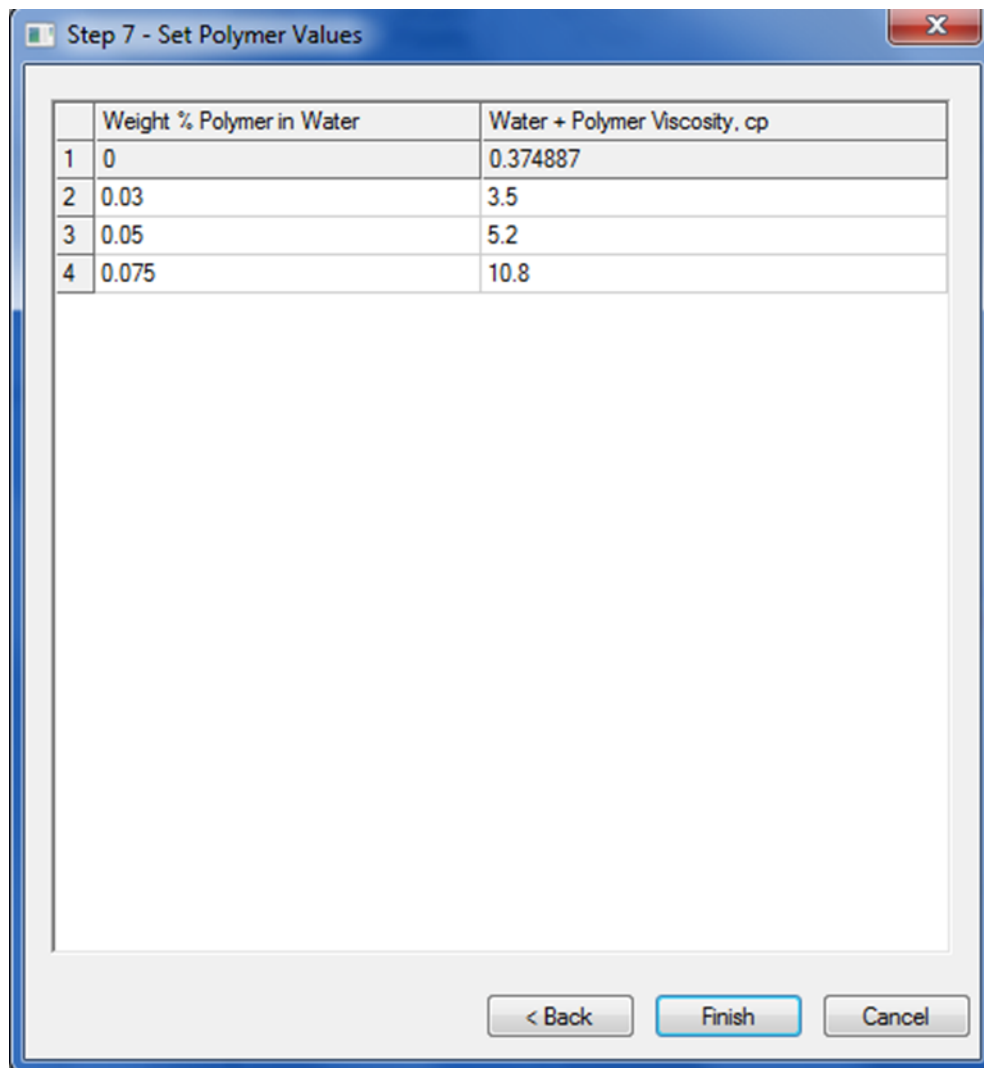


Fig. 3.11: Set Polymer Values

Chapter 4 Results and Discussion

4.1 Introduction

4.1.1 Basic Information Of Heglig Oilfield

Heglig oilfield is one of the largest oilfields in Sudan, the field had been producing Hydrocarbons since 1999, The oil production was reported to have peaked in 2006, and declined ever since, the most water production problems in Sudan were observed in this field, and the water cut was reached 95% (Elbrir 2018). Previous studies in screening of EOR methods for the Sudanese oil fields show that the field is suitable candidate for cEOR operation (Husham 2015). ASP flooding possess the highest potential with oil recovery over waterflood ranging between 12%-18%. (Wang Qiang 2013).

The Greater Heglig Oilfield is located in the southeast and middle of Block 2B, Muglad Basin. The oilfield consists of 8 major fields, namely Heglig main, Toma, El Bakh, El Ful, Laloba, Kanga, Barki and Simbir East. This study is focused on Heglig main oilfield which consists of four reservoirs, namely Aradeiba Main, Bentiu 1, Bentiu 2 and Bentiu 3. (Husham 2015).

4.1.2 Basic Reservoir Characteristics and Parameters

Heglig field is located on the northeast flank of the intracratonic Muglad rift basin. The northwest-southeast trending Muglad basin complex covers an area of 750km (465mi) long and in excess of 150km (95mi) wide. The drive mechanism is bottom and edge water with moderate to strong aquifer strength. (Yagoub 2010)

Table 4.1: Summary of Reservoir Characteristics (Naganathan 2006)

Reservoir	Lithology	Sedimentary Facies	Porosity (%)		Permeability (md)	
			Range	Average	Range	Average
Aradeiba	fine to medium grained	meandering stream	26.4-36.5	32.3	780-6436	3261
Bentiu	fine to coarse grained	braided stream	24.2-31.6	29.1	561.5-2926	2041.2

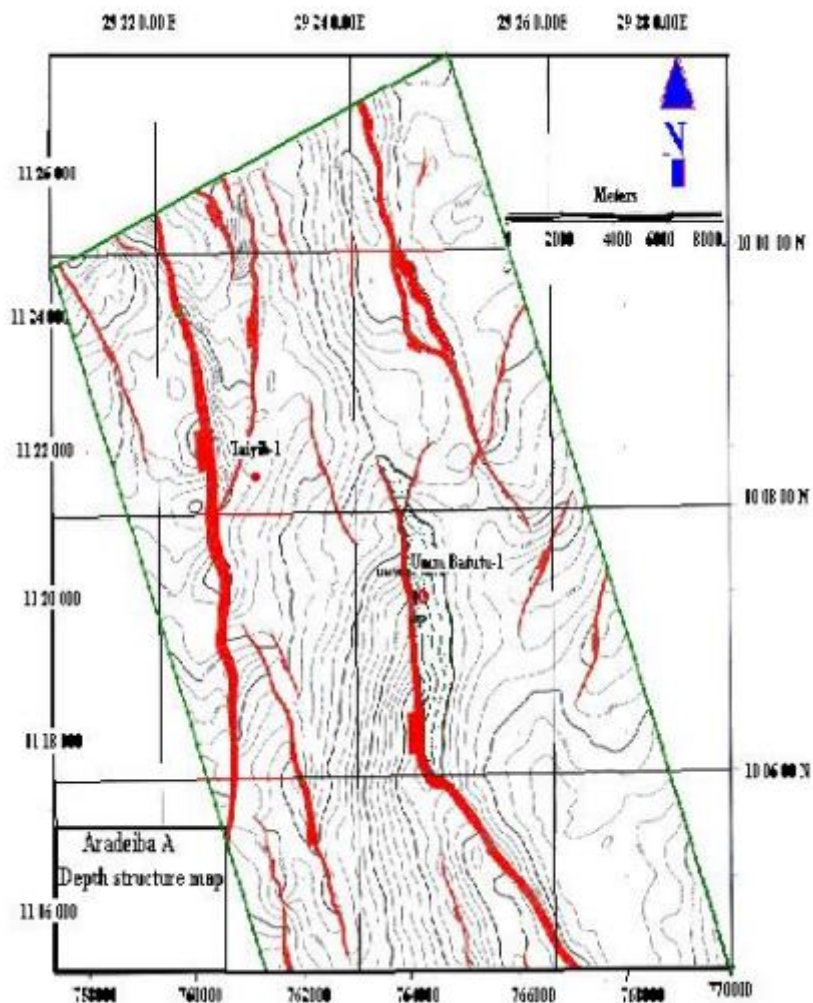


Fig.4.1: Aradeiba A Formation depth structure map (Yagoub 2010)

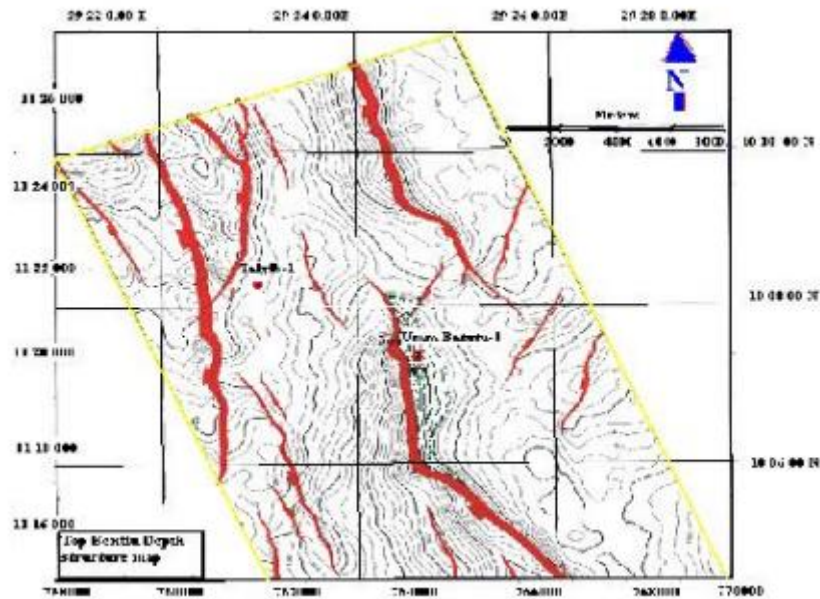


Fig.4.2: Bentiu-1A Formation depth structure map (Yagoub 2010)

4.1.3 Original Oil In Place And PVT Data

Heglig Main field STOIP reaches as high as 577.95 MMSTB, which is 63.2 % of the total STOIP of Greater Heglig. (Husham 2015)

Table 4.2:PVT data from Heglig oilfield (Abbas 2018)

API	29°
Formation Volume Factor (rb/stb)	1.05
Reservoir Temperature	167
Gas Oil Ratio	2
Bottom hole Pressure	47
Oil viscosity (cP)	19
Oil density (lb/ft ³)	54.5
Gas specific gravity	1.048
Water Salinity (ppm)	1087

4.2 Heglig CMG Model.

4.2.1 Geological Units

The model is composed of 212 layers , divided to 21 zones as illustrated in figure (4.3) .

From Layer	To Layer	Unit Name
1	24	Zone 0 - Aradeiba main
25	25	Zone 1 - shale
26	60	Zone 2 - Aradeiba B
61	61	Zone 3 - shale
62	62	Zone 4 - Aradeiba C
63	63	Zone 5 - shale
64	64	Zone 6 - Aradeiba D
65	74	Zone 7 - Aradeiba E
75	75	Zone 8 - shale
76	93	Zone 9 - Aradeiba F
94	101	Zone 10 - shale
102	112	Zone 11 - Bentiu 1A
113	124	Zone 12 - Bentiu 1B
125	132	Zone 13 - Bentiu 1C
133	150	Zone 14 - Bentiu 1D
151	151	Zone 15 - Bentiu 1E
152	152	Zone 16 - shale
153	169	Zone 17 - Bentiu 2A
170	170	Zone 18 - Bentiu 2B
171	171	Zone 19 - Bentiu 2C
172	172	Zone 20 - Bentiu 2D
173	173	Zone 21 - Bentiu 2E
174	174	Zone 22 - shale
175	194	Zone 23 - Bentiu 3A
195	211	Zone 24 - Bentiu 3B
212	212	Zone 25 - Bentiu 3C

Fig 4.3: Geological Units Of Heglig Sector Model

The two wells were both perforated in (Bentiu1A) and (Bentiu1B) from layer 107 to layer 120.

4.2.2 Grid thickness

Figure (4.4) shows that the model consist of 154548 grids 27x27x212(I,J,K) with single porosity

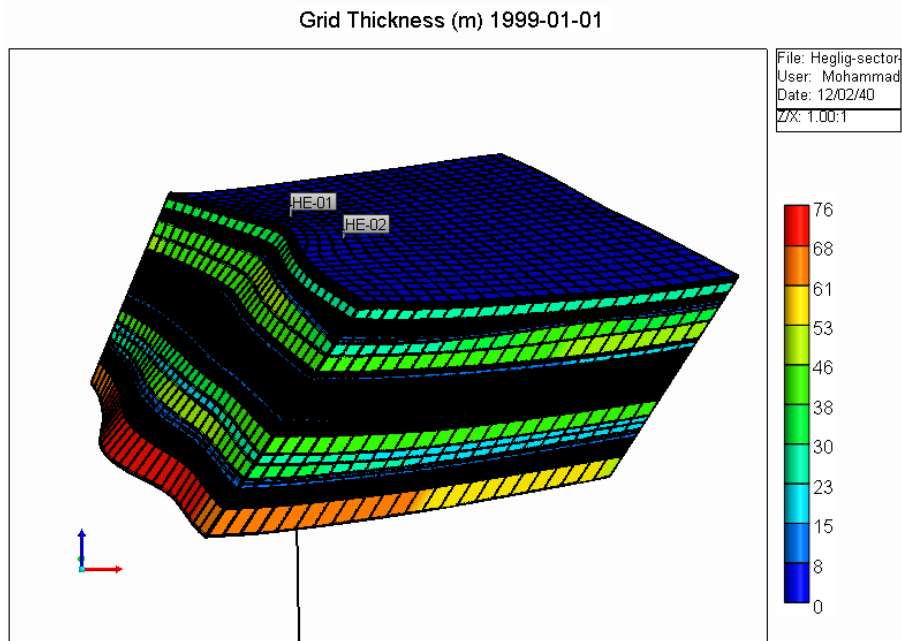


Figure 4.4: Grid Thickness Distribution in the Heglig sector model

4.2.3 Porosity Distribution

Figures (4.5) and (4.6) , show the porosity distribution in the Heglig sector model which is a sequence of massive and continuous sandstones interceded with shale's ,with porosity ranging from 7% to 35% .

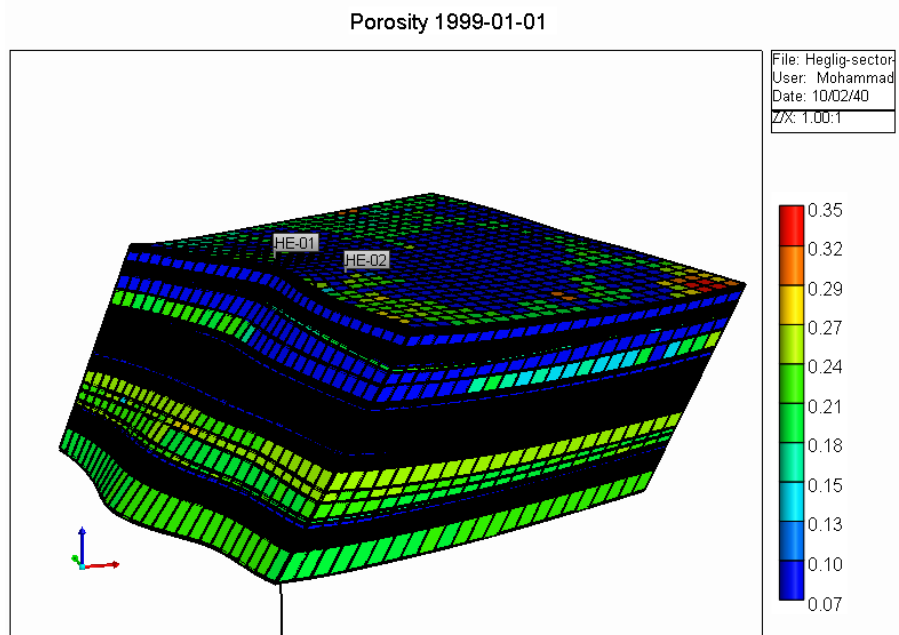


Figure 4.5 Porosity Distribution in the Heglig sector model (3D view)

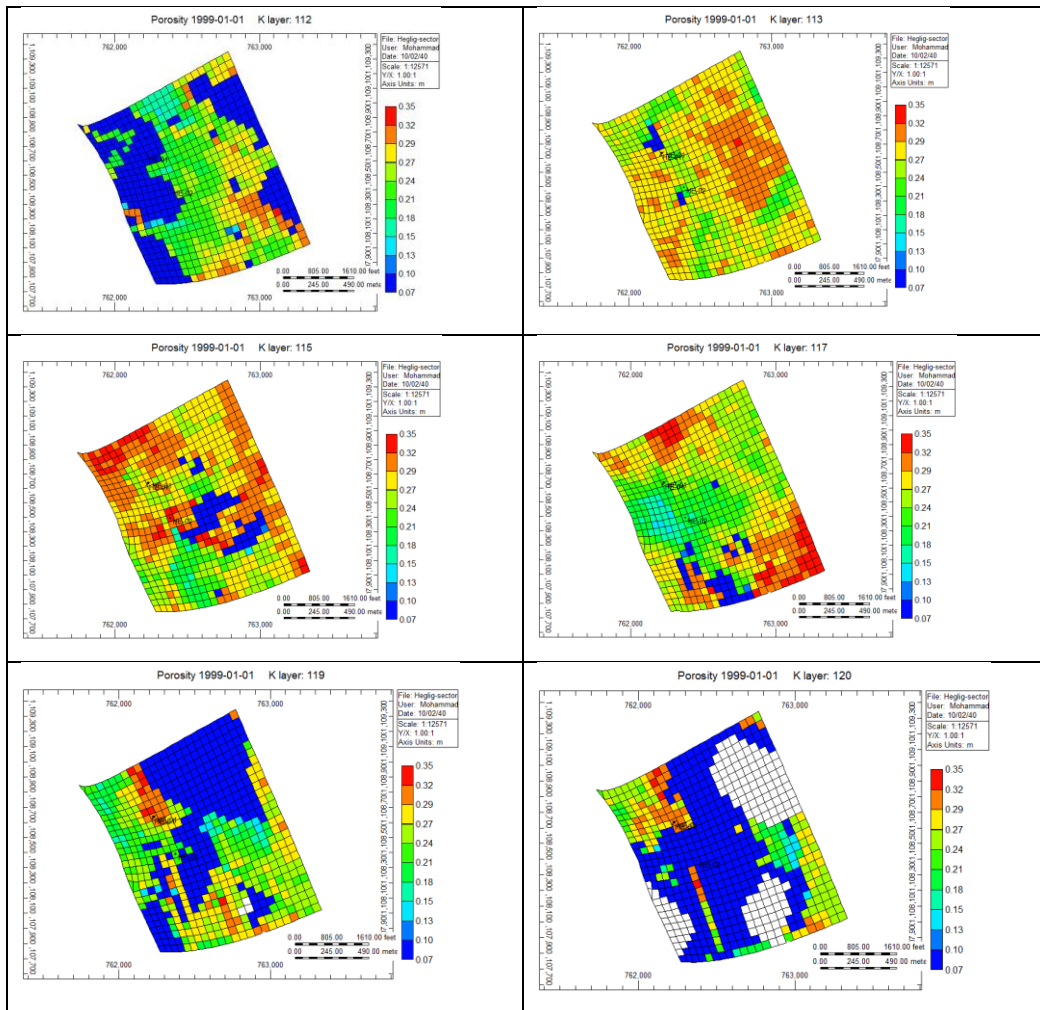


Figure 4.6: Porosity Distribution in the Heglig sector model (2D view)

4.2.4 Permeability Distribution

Figures (4.7) and (4.8) shows the permeability Distribution in (Bentiu 1A in layers 107,110,112), and (Bentiu 1B in layers113,116,117,119,120), the permeability ranges approximately between 100 and 2900 md.

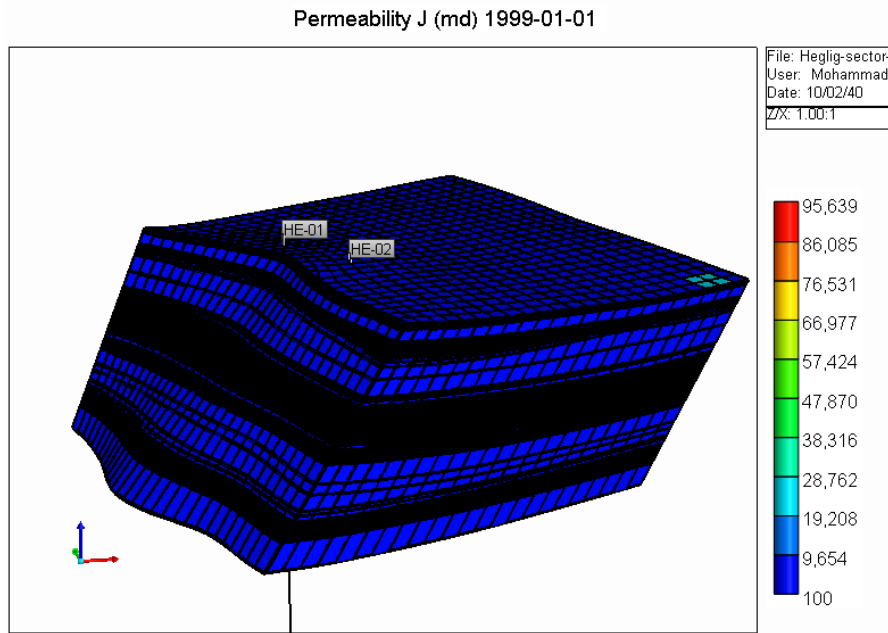


Fig 4.7: Permeability Distribution (3D view)

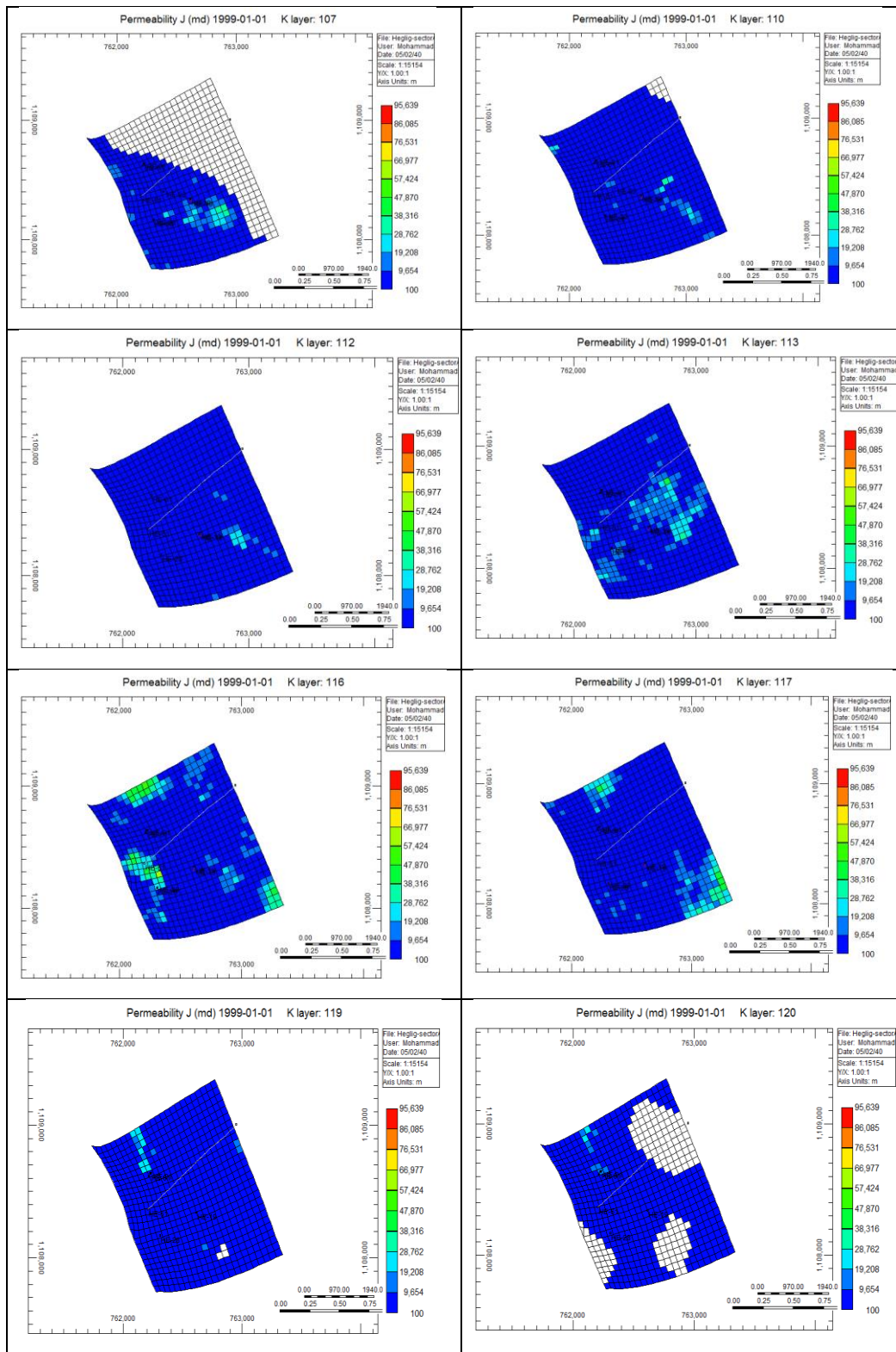


Fig 4.8: Permeability Distribution (3D view)

4.2.5 Fluid properties

Table 4.3: properties of water phase

Property	Water phase
FVF (bbl./STB)	1
density (g/cm ³)	0.973376
viscosity (cp)	0.361307

Table 4.4: properties of oil phase

FVF (bbl/STB) @10*10 ⁶ Pa	1.025
density (g/cm ³)@10*10 ⁶ Pa	0.872
viscosity (cp)	4.5091
gas oil ratio	1.9253

Table 4.5: properties of gas phase

FVF (bbl/STB) @10*10 ⁶ Pa	0.01277
density (g/cm ³)@10*10 ⁶ Pa	0.07157
viscosity (cp)	0.01675

4.2.6 Initial Conditions

The initial reservoir conditions are shown below in table 4.4.

Table 4.6: Initial Reservoir conditions

reference depth	1223 m
reference pressure	10342.1 kPa
water oil contact	1223 m
Gas oil contact	1015 m

4.3 Sensitivity Tests

4.3.1 Introduction

The sensitivity tests parameters are presented in form of graphs and tables. These parameters are injection rate, chemical solution concentration (i.e. Water Alkaline Surfactant Polymer mixture concentrations), and liquid production rate.

Each of the these parameters is iterated with other parameters fixed to obtain the best choice, then the best choice is fixed in the subsequent iterations. The resulted cumulative oil and cumulative water of each iteration are then plotted (Y axis), against time (X axis). The model consists of a well pair, an injector (HE-01) and a producer (HE-02), it was assumed that the producer hasn't produced before, the two wells were opened and the injection was started at the same date which is 1/Jan/1999 and simulated until 1/Jan/2020.

4.3.2 Do Nothing Case (Base Case)

In this case the producer well (HE-02) was let to produce, and the the injector well (HE01) was Shut-in, in this case, the cumulative Oil Produced was 22.134 MMbbl , and the cumulative water Produced was 853.848 MMbbl.

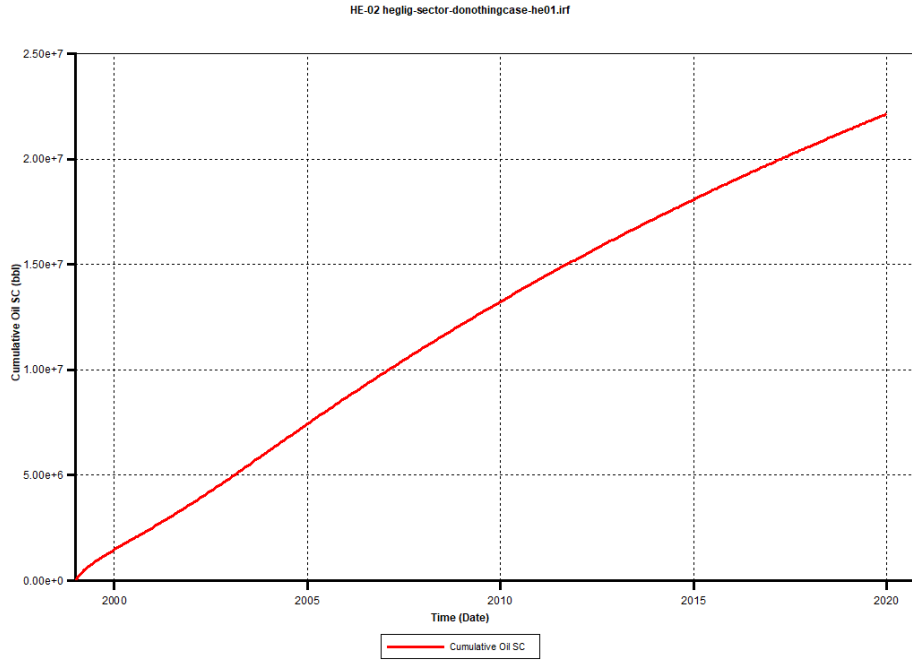


Fig 4.9 Cumulative oil production for the Do Nothing Case

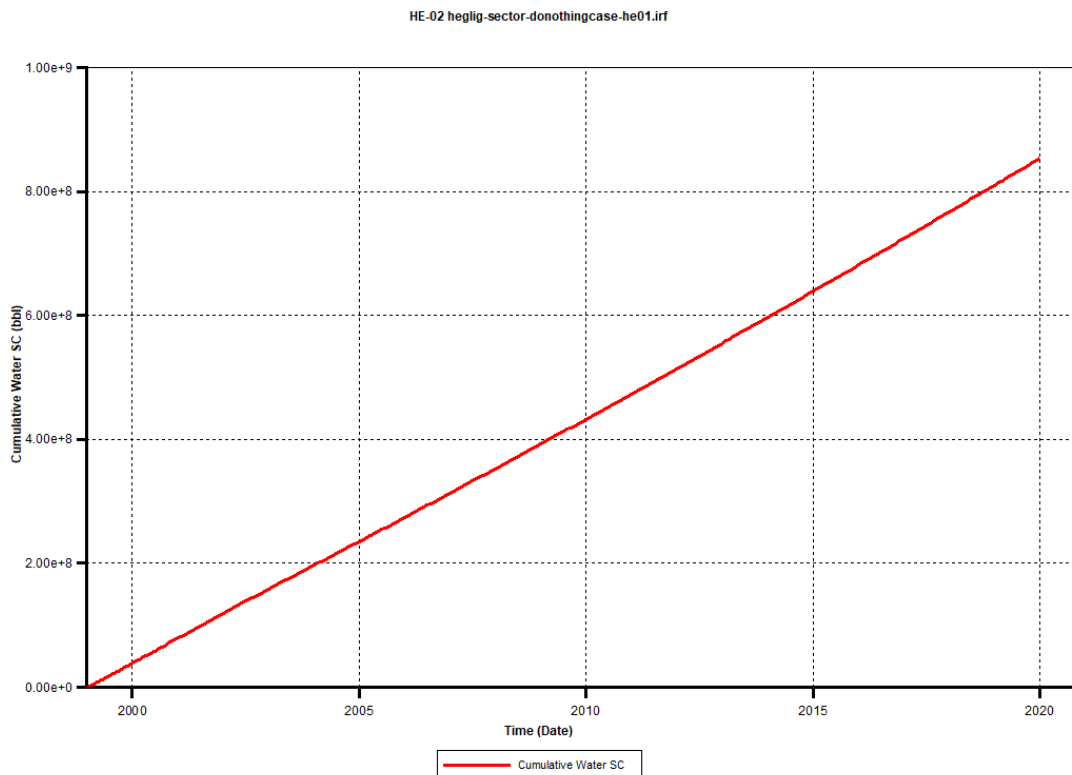


Fig 4.10 Cumulative water production for the Do Nothing Case

4.3.3 Concentrations of the Chemical Solution

The effect of the solution concentrations is studied by specifying the components percentages in the Injector Well (HE-02), by double clicking on the well name in the tree view under Wells & Recurrent (figure 4.11)

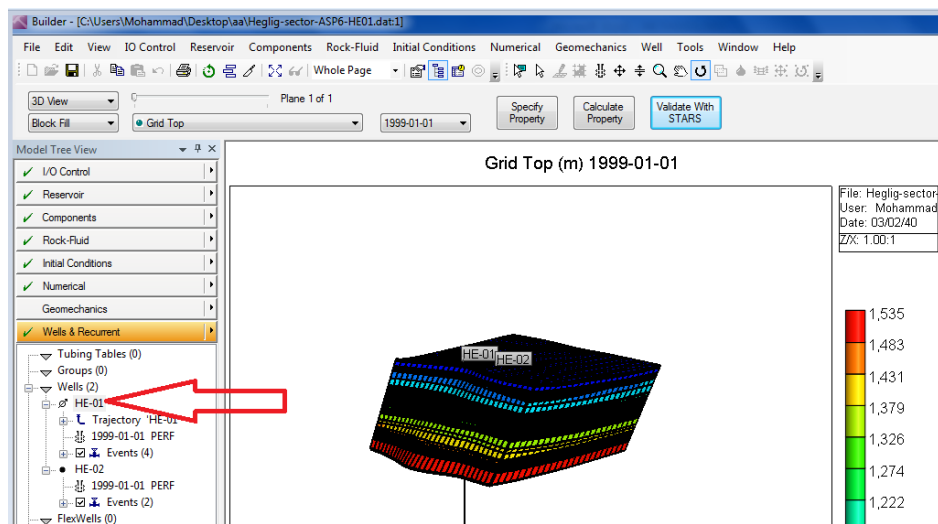


Fig 4.11 Opening well event window of the injector well

Well events window will open, then click on injected fluids, a table for components concentrations will show up, in this table the concentrations can be specified (figure 4.12).

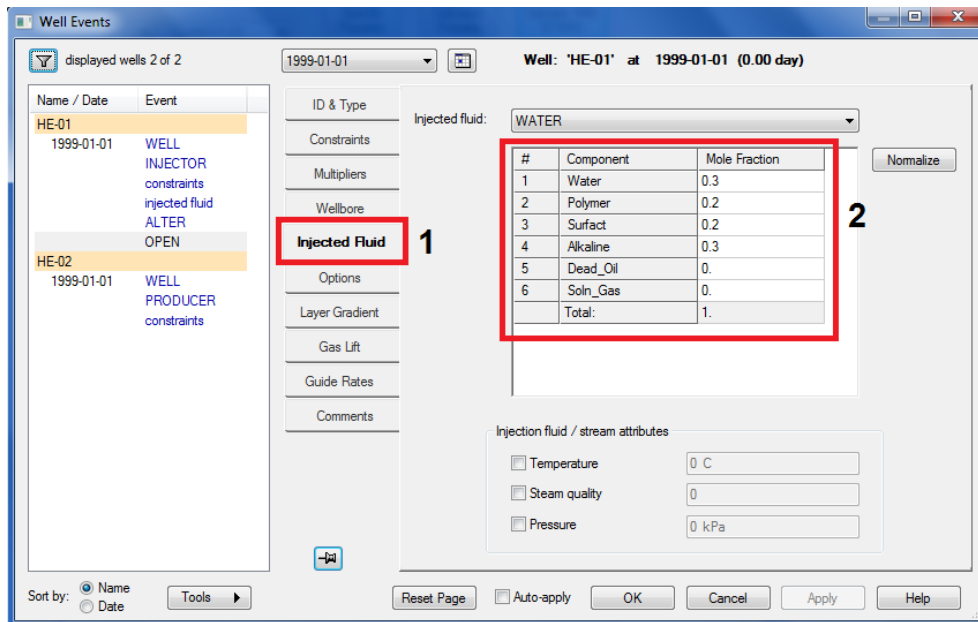


Fig 4.12 Specifying the chemical concentrations

Table 4.7 shows Different ASP Concentrations and their Corresponding Cumulative Oil and Water Production, the best concentrations scenario is bolded .

Table 4.7: Iterations of ASP Concentration

Run	Concentration				Cumulative Oil Produced, MMbbl	Cumulative water Produced, MMbbl
	water	Alkaline	Surfactant	Polymer		
1	0.3	0.3	0.2	0.3	22.406	830.979
2	0.2	0.2	0.1	0.5	22.402	825.37
3	0.4	0.4	0.1	0.1	22.466	825.028
4	0.2	0.3	0.2	0.3	22.4	829.497
5	0.2	0.2	0.2	0.4	22.397	827.714

The results show that a combination of 0.4wt% of Water, 0.4wt% of Alkaline, 0.1wt%, of Surfactant and 0.1wt% of Polymer (Iteration 3),

will yield a maximum cumulative Oil (22.466 MMbbl) , and a minimum cumulative water (825.028 MMbbl), also taking into consideration the minimum amount of polymer and surfactant required for this scenario, it is considered the optimum scenario.

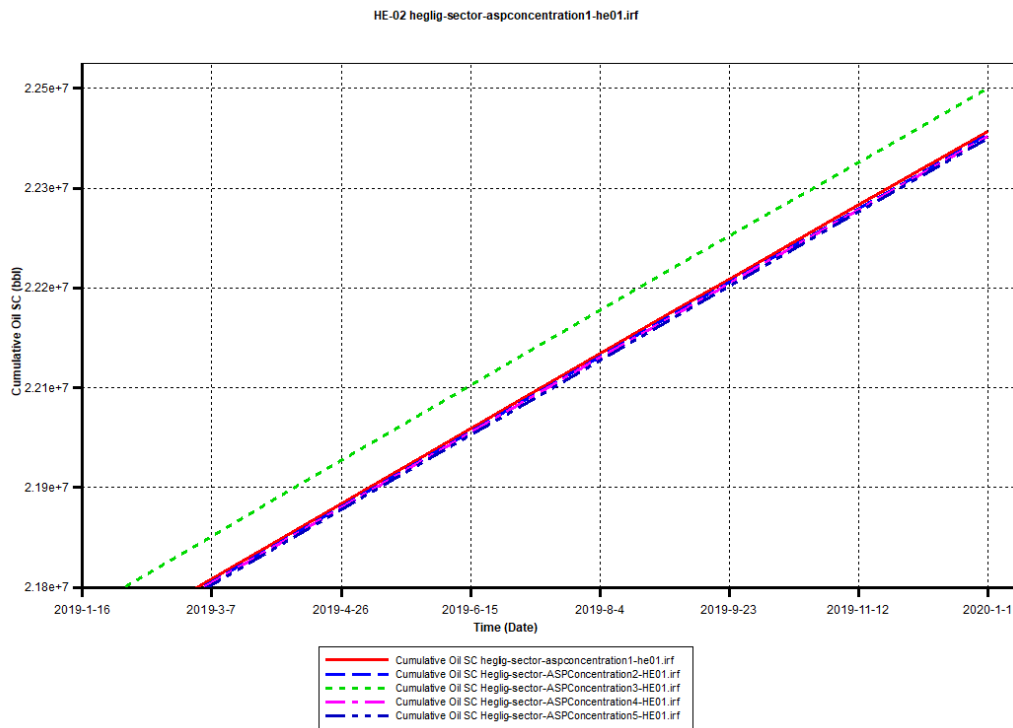


Fig 4.13:A Comparison between the cumulative oil production of all concentrations scenarios

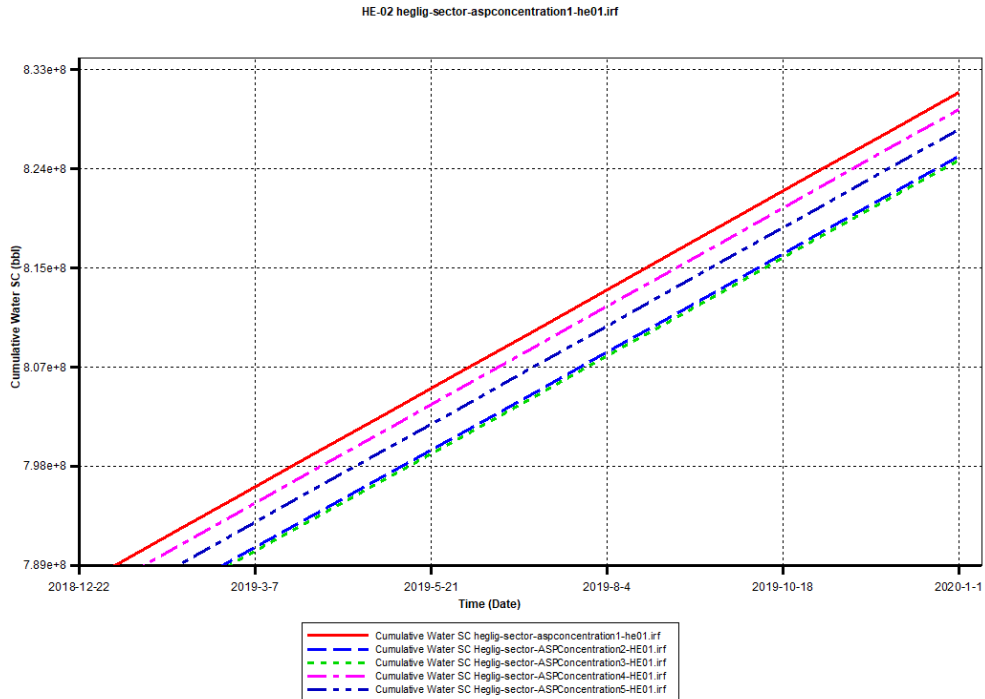


Fig 4.14:A Comparison between the cumulative water production of all concentrations scenarios

4.3.3 Injection Rate

To change the injection rate open well events window for the injector well as shown previously , then click on **constraint** , from parameters list select **STW Surface water rate**, then tick on **change current primary constraint** and specify the required injection rate, then click **ok** See (figure 4.15).

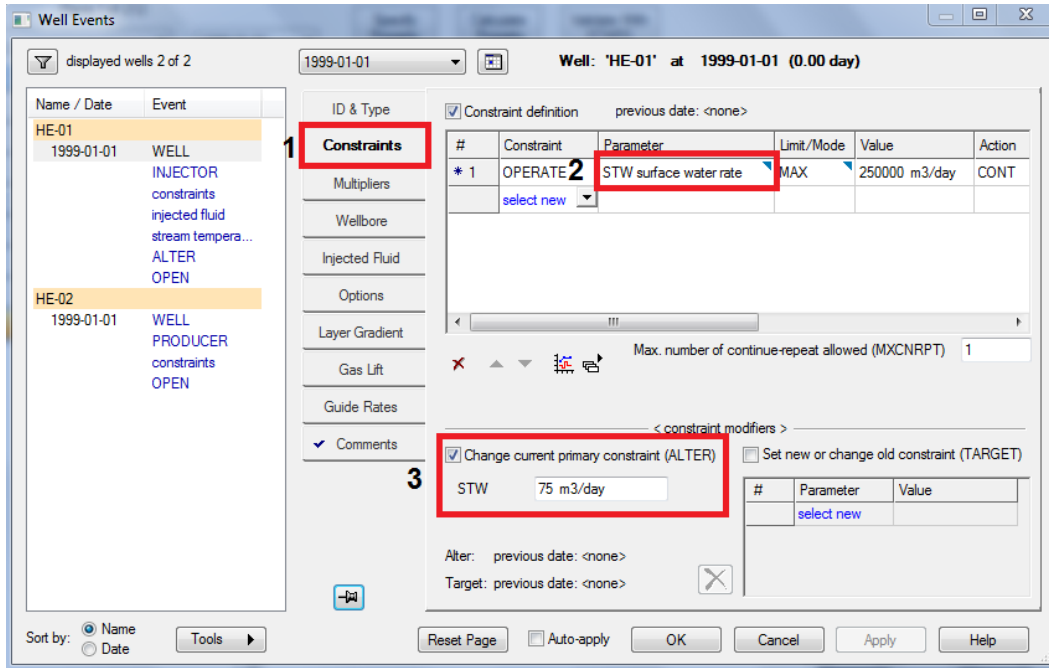


Fig 4.15: specifying the Injection rate

The iterations for the injection rate are shown in table, the optimum injection rate is bolded.

Table 4.8: Cumulative Oil and Cumulative Water Produced for Each Injection Rate

Run	Injection rate		Cumulative Oil Produced, MMbbl	Cumulative Water Produced, MMbbl
	m^3/d	bb/d		
1	75	11.924	22.466	825.028
2	100	15.899	22.498	818.097
3	150	23.849	22.509	806.832
4	200	31.797	22.445	791.862
5	250	39.747	22.481	781.497

The results show that, injection rate of 23.849 bbl/d (iteration 3), will yield cumulative Oil of 22.509 MMbbl, which is the maximum amount of cumulative oil compared to the other iterations, but injection

rate of 39.747 bbl/d (iteration 5) will yield cumulative oil of 22.481 MMbbl which is only lower by 0.028 MMbbl than the cumulative oil obtained from (iteration 3), but it will yield the lowest cumulative water which is 781.497 MMbbl , and it is is lesser by 25.335 MMbbl than the cumulative water obtained from (iteration 3), thus injection rate of 39.747 bbl/d will be considered the optimum injection rate.

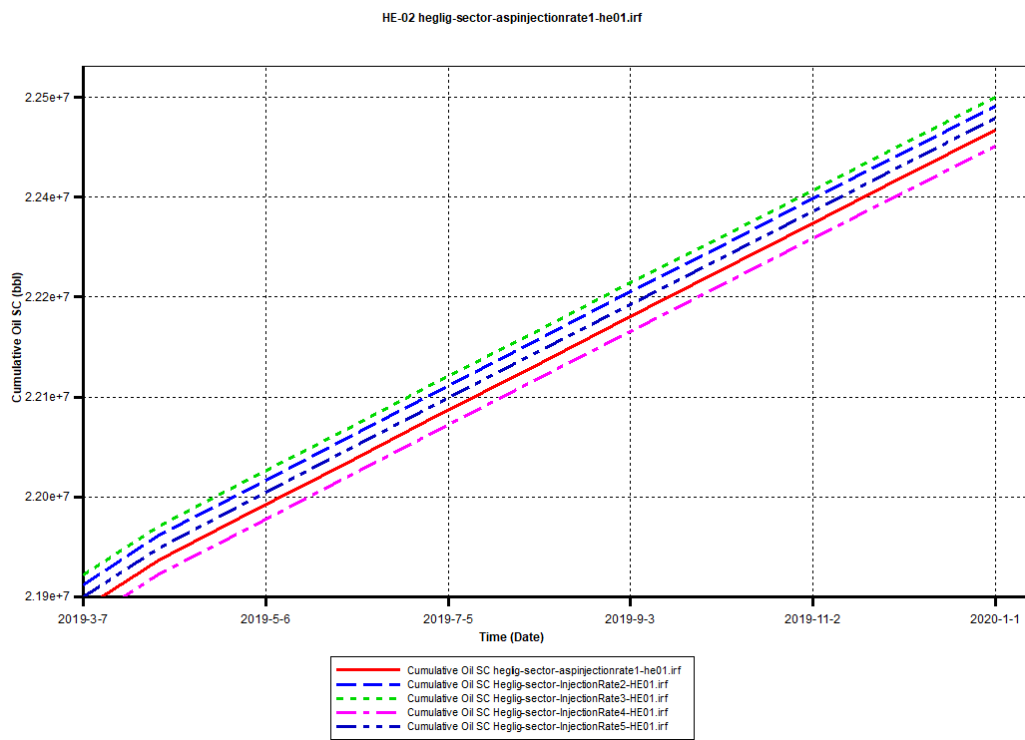


Fig 4.16:A Comparison between the cumulative oil production of all injection rate scenarios

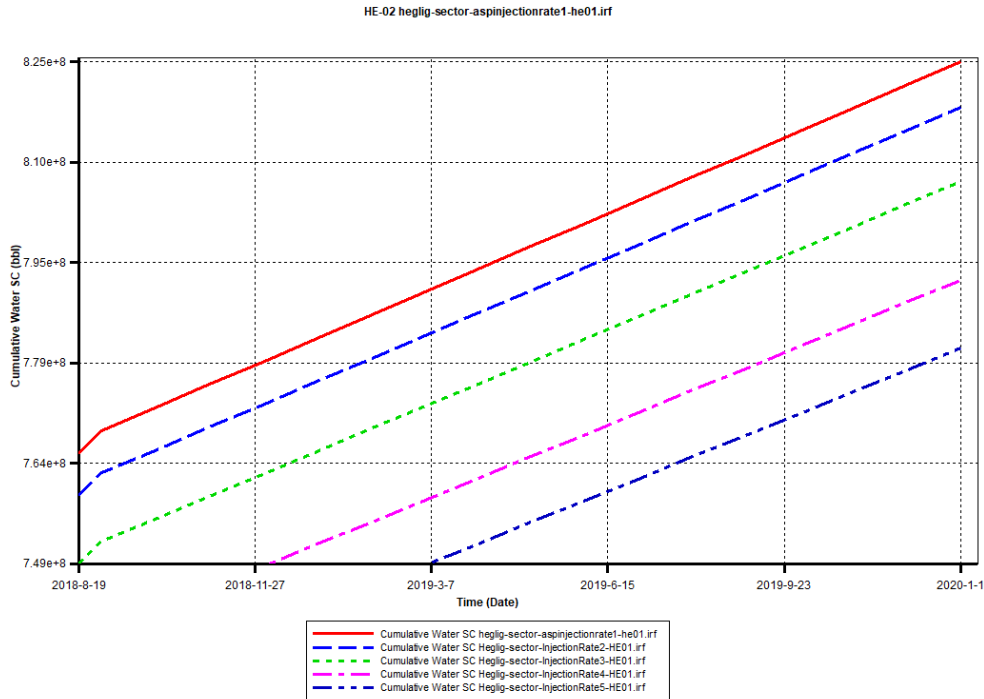


Fig 4.17:A Comparison between the cumulative water production of all injection rate scenarios

4.3.4 Surface Liquid Production Rate

To change the Surface production rate, open well events window for the Producer well, then click on **constraint**, from parameters list select **STL Surface liquid rate**, then tick on **change current primary constraint** and specify the required rate, then click **ok** See (figure 4.18).

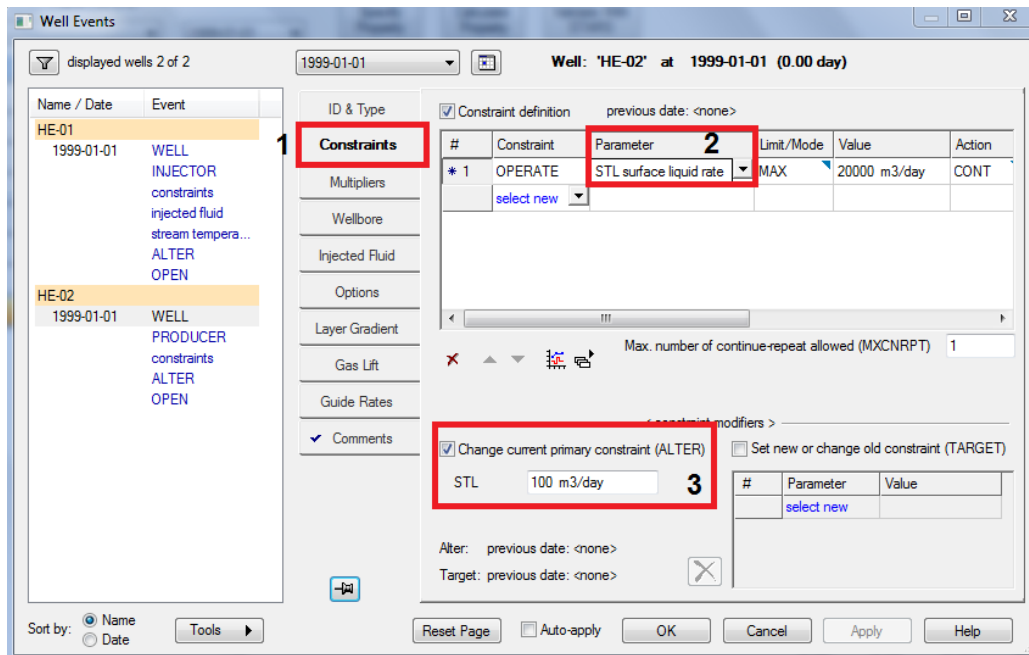


Fig 4.18: specifying the Surface Production rate

The iterations are shown in table 4.9 , the optimum production rate is bolded.

Table 4.9: Cumulative Oil and Cumulative Water Produced for Each production Rate

Run	Surface Production Rate		Cumulative Oil Produced, MMbbl	Cumulative Water Produced, MMbbl
	m^3/d	bbl/d		
1	100	628.981	0.132	4.692
2	200	1257.962	0.238	0.941
3	300	1886.944	0.331	1.414
4	400	2515.925	0.416	1.888
5	500	3144.906	0.499	2.362
6	1000	6289.812	0.931	4.731
7	2000	12579.624	2.021	0.945

8	4000	25159.25	5.206	187.009
9	10000	62898.12	14.615	467.813
10	20000	125796.24	22.616	787.547

From the results above we can see that Surface liquid Production Rate

Of 125796.24 bbl/d will yield a maximum amount of Cumulative oil produced which is 22.616 MMbbl, thus it is considered the optimum liquid Production Rate.

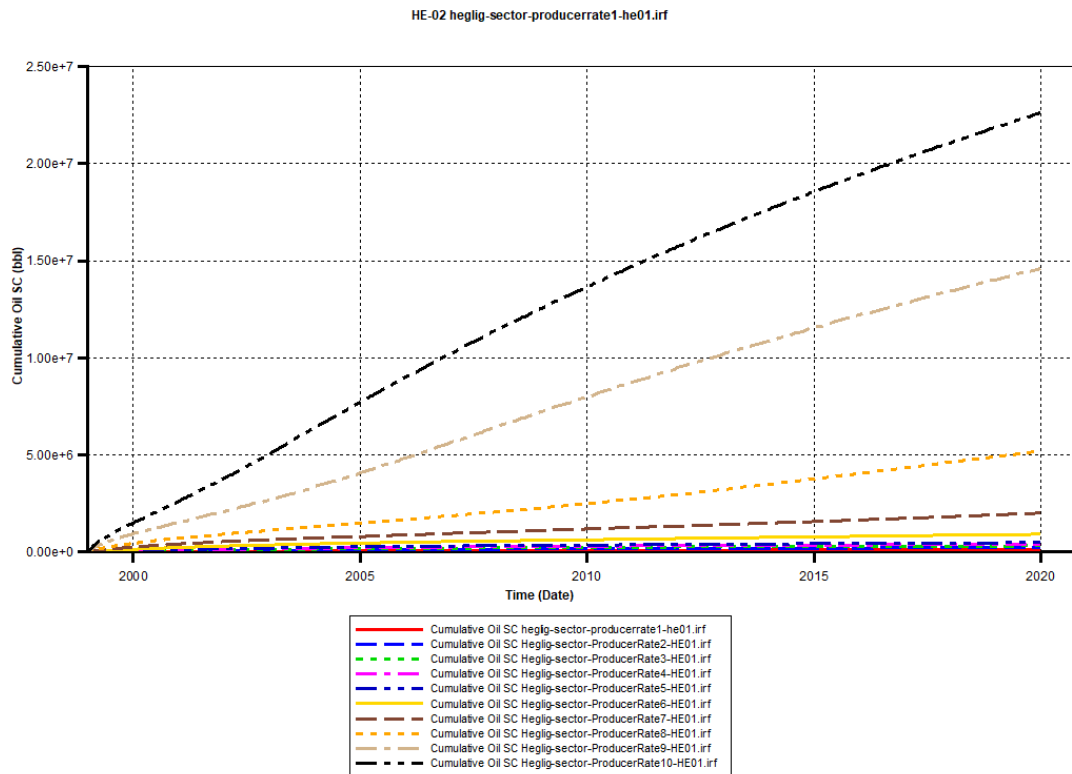


Fig 4.19:A Comparison between the cumulative oil production of all production rate scenarios

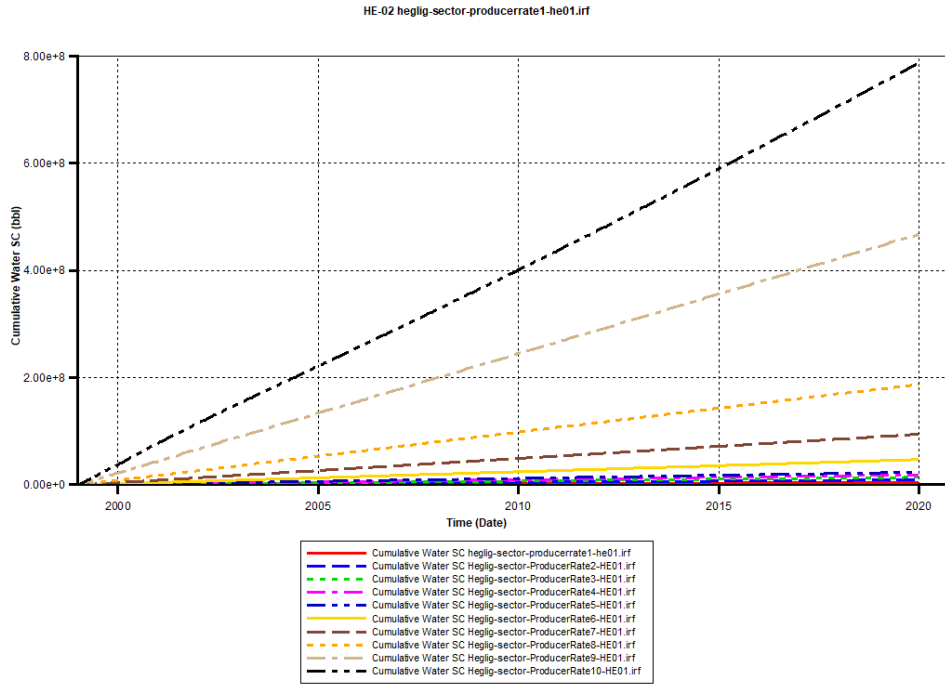


Fig 4.20:A Comparison between the cumulative water production of all production rate scenarios

4.4 Final Results

The optimization of the injection and production parameters lead to obtain an increment of 0.482 MMbbl in the cumulative oil production, and a decrement of 66.3 MMbbl in the cumulative water production, compared to the base case. The optimum chemical concentration is 0.4wt% of Alkaline, 0.1wt%, of Surfactant and 0.1wt% of Polymer, the optimum injection rate is 250 m³/d (39.747 bbl/d) and, the optimum production liquid rate is 20000 m³/d (125796.24 bbl/d).

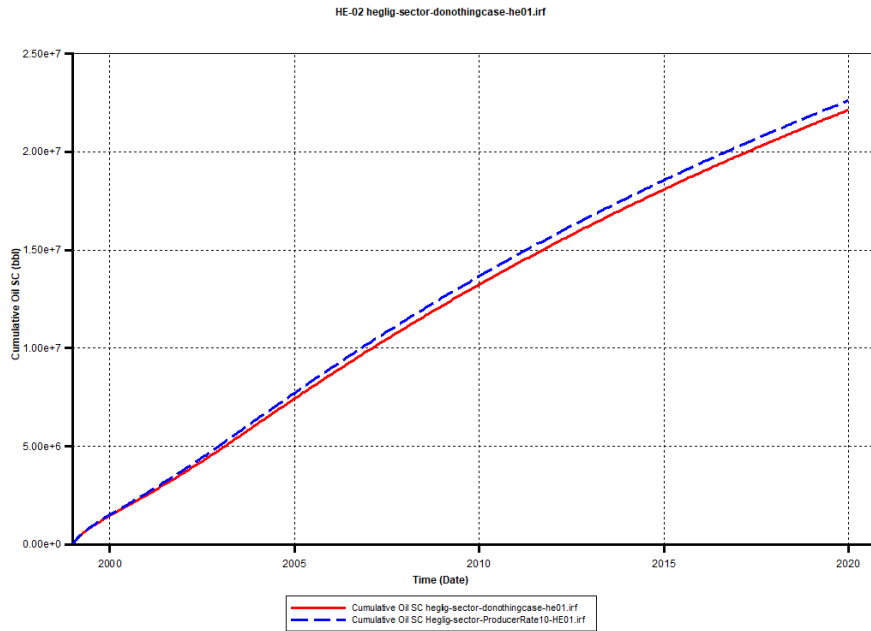


Fig 4.21:A Comparison between the cumulative oil production of the base case and the optimized case

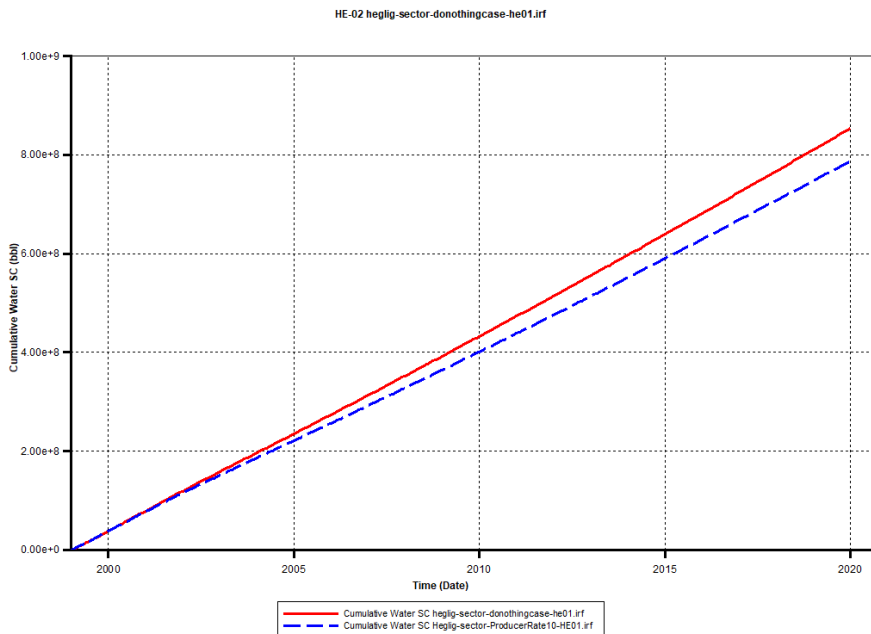


Fig 4.22:A Comparison between the cumulative water production of the base case and the optimized case

Chapter 5 Conclusions and Recommendations

5.1 Conclusions

- The possibility of increasing the recovery factor for Heglig main oilfield has been studied.
- Designing of a well pair ASP Flooding model for Heglig main oilfields using CMG software has been implemented.
- The optimum chemical injection and production parameter had been proposed (the optimum chemical concentration is 0.4wt% of Alkaline, 0.1wt%, of Surfactant and 0.1wt% of Polymer , the optimum injection rate is 250 m³/d (39.747 bbl/d) and the optimum production liquid rate is 20000 m³/d (125796.24 bbl/d)),
- The ASP flooding increased the cumulative oil production by 0.482 MMbbl and decreased the cumulative water production by 66.3 MMbbl.

5.2 Recommendations

- It is recommended to perform detailed studies to propose the optimum well locations, and the optimum perforations locations.
- It is also recommended to perform a detailed economical evaluation of the flooding processes.

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