

بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ



Sudan university of science and technology
College of Petroleum and Mining engineering
Department of petroleum engineering



Project Title:

Chemical ASP Design for a Sudanese Oil fields

(case study Heglig main)

تصميم الإستخلاص الكيميائي المعزز للنفط في الحقول السودانية

(دراسة حالة حقل هجليج الرئيسي)

Submitted in Partial Fulfillment of the Requirements of the Degree
of B.Sc. in Petroleum Engineering

Prepared by:

1. Mohammed abdurauf abu algasim alfaki
2. Mohammed abd alwahab mohammed abd allah
3. Munir mohammed Ibrahim ahmed
4. Osman alzain alshareef Alhassan

Supervisor:

Eng. Muhanned mahgoub khairy

November-2020

بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ



Sudan university of science and technology
College of Petroleum and Mining engineering
Department of petroleum engineering



Project Title:

Chemical ASP Design for a Sudanese Oil fields

(case study Heglig main)

تصميم الإستخلاص الكيميائي المعزز للنفط في الحقول السودانية

(دراسة حالة حقل هجليج الرئيسي)

This project is accepted by college petroleum engineering and
technology department of petroleum engineering

Prepared by:

- 1- Mohammed abdurauf abu algasim alfaki
- 2- Mohammed abd alwahab mohammed abd allah
- 3- Munir mohammed Ibrahim ahmed
- 4- Osman alzain alshareef Alhassan

Project Supervisor: Eng. Muhanned mahgoub khairy

Signature:.....

Head of Department: Eng. Abdelwhab Mohamed Fadoul.

Signature:.....

Dean of College: Dr. Elham Mohammed Mohammed Khair.

Signature:.....

Date: / / 2020

الآية

قال تعالى

(اقْرَأْ بِاسْمِ رَبِّكَ الَّذِي خَلَقَ (1) خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ (2) اقْرَأْ وَرَبُّكَ الْأَكْرَمُ (3) الَّذِي عَلَّمَ بِالْقَلَمِ (4) عَلَّمَ
الْإِنْسَانَ مَا لَمْ يَعْلَمْ) (5)

سورة العلق الآية 1-5

صدق الله العظيم

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. Muhanned mahgoub khairy 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.

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

Acknowledge

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.

A special gratitude we give to our final year project supervisor. Muhanned Mahgoub Khairy, have invested his full effort in guiding the team in achieving the goal, and helped us to coordinate our project especially in writing this report.

Thanks to all our friends for encouragement in many moments.

Thanks to College of Petroleum Engineering and Technology, especially all the members of the petroleum Engineering department.

Last but not least, many thanks go to our Dean of the faculty Dr. Elham Mohammed Mohammed Khair for the continuous encouragement.

Abstract

Chemical Enhanced Oil Recovery (cEOR) can increase the recovery factor for many oilfields. In Heglig oilfield EOR method has been investigated on several levels in order to select the best application. The screening criteria of each method depend on the reservoir history (Moreno et al., 2014). Several EOR methods have been introduced including thermal EOR and non-thermal methods. Chemical enhanced oil recovery (CEOR) is a nonthermal method; it has shown high applicability in several conditions.

Heglig main 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% with low recovery factor 22.2%. (29th DTR, GNPOC, 2012)

This study aims to study the possibility of increasing the recovery factor by using chemical ASP injection for Heglig main oilfield.

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

Two mainly cases were implemented by using CMG simulator, the first case implemented by using two wells (HE-19 , HE-28) (base case), the second case which implement three wells (HE-19,HE-28,HE-INJ).

The result show increasing in cumulative oil production by 9% and, decreasing in cumulative water production by 21%

Pilot results has been set as matching results in order to further refine to the chemical EOR full-field model

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

التجريد

الاستخلاص الكيميائي المعزز للنفط يمكن من زيادة معامل الاستخلاص في معظم الحقول النفطية, في حقل هجليج النفطي معظم طرق الاستخلاص المعزز للنفط تم التحقق منها في عدة مستويات لاختيار الطريقة الانسب للتطبيق, عوامل الفحص لاي طريقة تعتمد على تاريخ المكن, هذه الطرق تتضمن الاستخلاص الحراري و الاستخلاص الكيميائي, الاستخلاص الكيميائي اظهر قابليته للتطبيق في مختلف الظروف.

حقل هجليج النفطي يقع في الجنوب الشرقي و الوسط من المربع 2B في حوض المجلد و يعد من اكبر

الحقول النفطية في السودان و بدأ الانتاج منه منذ العام 1999 و قد سجل اعلى انتاج له في عام 2006 ثم بدأ بعد ذلك بالتناقص

يتكون حقل هجليج من طبقات الحجر الرملي و الطبقات الطينية و معظم المشاكل المتعلقة بانتاج الماء قد تمت ملاحظتها في هذا الحقل, حيث وجد أن المياه المنتجة مع النفط قد بلغت 9% مع معامل إستخلاص 22% الهدف من هذه الدراسة هو دراسة امكانية زيادة معامل الإستخلاص بواسطة الحقن الكيميائي (حقن

ASP) لحقل هجليج الرئيسي و هذه الدراسة تمت بإستخدام تطبيق المحاكاة المكنية CMG

تم تطبيق حالتين بإستخدام محاكي CMG, الحالة الأولى طبقت بإستخدام بئر (ما قبل الحقن), الحالة الثانية طبقت بإستخدام ثلاثة ابار (ما بعد الحقن)

النتائج المتحصل عليها وضعت كمقارنات لتستخدم بطريقة اوسع و لتطبق على كل الحقول.

يوصى بإجراء دراسة مفصلة لتطبيق هذه الدراسة في افضل موقع للابار و افضل موقع للتثقيب و وضع دراسة اقتصادية مفصلة لعملية الحقن.

Contents

الآية.....	I
Dedication	II
Acknowledge	III
Abstract	IV
التجريد	V
Chapter 1	- 1 -
Introduction	- 1 -
1.1Chemical ASP flooding.....	- 1 -
1.1.1The function of alkaline, surfactant, and polymer during ASP.....	- 1 -
1.1.2Oil recovery mechanisms in ASP flooding.....	- 2 -
1.2Chemical EOR surfactant	- 2 -
1.3Problem statement	- 3 -
1.4 Objectives	- 3 -
1.5 About the field	- 3 -
Chapter 2	- 6 -
Theoretical background and Literature review	- 6 -
2.1 Types of EOR Techniques	- 6 -
2.1.1Thermal Recovery.....	- 6 -
2.1.2Chemical Injection.....	- 8 -
2.1.3Gas Injection.....	- 8 -
2.2 Using Enhanced Oil Recovery Methods	- 8 -
2.3Chemical surfactant properties	- 9 -
2.3.1The hydrophobic effect and micelle formation.....	- 9 -
2.3.2Critical micelle concentration.....	- 9 -
2.3.3The krafft point.....	- 10 -
2.3.4Analysis.....	- 10 -
2.3.5Surface elasticity.....	- 11 -
2.3.6 Surface Rheology.....	- 11 -
Dilational viscosity.....	- 12 -
2.4 the systematic Classifications of surfactants.....	- 12 -
Chapter 3	- 19 -
Methodology	- 19 -
3.1 Equations used in model	- 20 -
.....	- 25 -
Chapter 4	- 27 -
Results and discussion	- 27 -
4.1 Basic Reservoir Characteristics and Parameters	- 27 -

4.2 Original Oil In Place And PVT Data	- 27 -
4.3 Heglig CMG Model	- 28 -
4.3.1 Geological Units	- 28 -
<i>Chapter 5.....</i>	- 41 -
<i>Conclusions and Recommendations</i>	- 41 -
5.1 Conclusions	- 41 -
5-2 Recommendations	- 41 -
<i>References</i>	- 42 -

list of Figures

FIG 1 - 1 STRUCTURE MAP FOR HEGLIG MAIN BANTUE-1 (HUSHAM A. ALI, 2015).....	4 -
FIG 1 - 2 VERTICAL WELLS PRODUCED FROM B1AA AND LOWER ZONE IN HELIG MAIN. (HUSHAM A. ALI, 2015)	5 -
FIG 2- 1 THERMAL RECOVERY SOURCE: ALBERTA GEOLOGICAL SURVEY	7 -
FIG 2- 2 CARBON DIOXIDE EOR SOURCE: LAWRENCE LIVERMORE NATIONAL LABORATORY	8 -
FIG 2- 3 EXAMPLE OF PHASE BEHAVIOR DIAGRAM FOR SURFACTANT IN AQUEOUS SOLUTION SHOWING THE CMC AND KRAFFT POINTS, (FROM SHINODA ET AL, { 11 }. COPYRIGHT 1963. ACADEMIC PRESS, NEW YORK.)	10 -
FIG 2- 4 REPRESENTATION OF THE 4 TYPES OF SURFACTANT. SOURCE: INKLINE. GR.-	16 -
FIG 3 - 1: THE GRID TOP AND WELL LOCATION IN HEGLIG MODEL IN 3D VIEW	25 -
FIG 3 - 2 THE GRID TOP AND WELL LOCATION IN HEGLIG MODEL IN 3D VIEW AFTER ADDING INJECTION WELL	26 -
FIG 3 - 3 INJECTED FORMATION AFTER THE INJECTION FINISHED AND HOW WATER SATURATION IS LOOKS LIKE	26 -
FIG 4 - 1 COMPARISON BETWEEN THE OIL RATE OF THE BASE CASE AND THE INJECTION CASE FOR WELL HE-19	30 -
FIG 4 - 2 COMPARISON BETWEEN THE WATER CUT OF THE BASE CASE AND THE INJECTION CASE FOR WELL HE-19	31 -
FIG 4 - 3 <i>COMPARISON BETWEEN THE OIL RATE OF THE BASE CASE AND THE INJECTION CASE FOR WELL HE-28</i>	32 -
FIG 4 - 4 COMPARISON BETWEEN THE WATER CUT OF THE BASE CASE AND THE INJECTION CASE FOR WELL HE-28	33 -
FIG 4 - 5 COMPARISON BETWEEN THE OIL RECOVERY FACTOR OF THE BASE CASE AND THE INJECTION CASE FOR ENTIRE FIELD.	34 -
FIG 4 - 6 WATER RATE IN HE-19 AFTER INJECTION CASE	35 -
FIG 4 - 7 WELL BOTTOM HOLE PRESSURE IN HE-19 AFTER INJECTION CASE	36 -

FIG 4 - 8 WELL BOTTOM HOLE PRESSURE IN HE-28 AFTER INJECTION CASE.....- 37 -

FIG 4 - 9 WATER RATE IN HE-28 AFTER INJECTION CASE.....- 38 -

FIG 4 - 10 *COMPARISON BETWEEN THE CUMULATIVE OIL PRODUCTION OF THE BASE CASE AND THE INJECTION CASE FOR ENTIRE FIELD.*- 39 -

FIG 4 - 11 COMPARISON BETWEEN THE CUMULATIVE WATER PRODUCTION OF THE BASE CASE AND THE INJECTION CASE.....- 40 -

List of Tables

TABLE 2 - 1: NONIONIC SURFACTANT EXAMPLES (HIRSCH, 2015)	- 14 -
TABLE 2-2 ANIONIC SURFACTANT CLASSIFICATIONS EXAMPLES (HIRSCH, 2015).....	- 15 -
TABLE 3 - 1 THE RELATIONSHIP BETWEEN SURFACTANT AND ALKALINE CONCENTRATIONS WITH IFT	- 23 -
TABLE 4 - 1 SUMMARY OF RESERVOIR CHARACTERISTICS (NAGANATHAN 2006)	- 27 -
TABLE 4 – 2 PVT DATA FROM HEGLIG OIL FIELD (ABBAS 2018)	- 28 -
TABLE 4 - 3	- 29 -

Nomenclatures

Ceor	Chemical Enhanced Oil Recovery
CMG	Computer Modeling Group
ASP	Alkaline, Surfactant, Polymer
STOIP	Stock Tank Oil Initially In Place
CSS	Cyclic Steam Stimulation
CMC	Critical Micelle Concentration
STOOIP	Stock Tank Original Oil In Place

Chapter 1

Introduction

Oil is the most used non-renewable source of energy in the world. Operation and service companies invest on many potential applications to increase oil production. The continuous research provides several solutions for existing techniques and new solution. Some of these techniques includes new well completion, digital well monitoring, multi-layer horizontal wells and optimizing sweep efficiency by enhanced oil recovery (EOR) (Raniolo et al., 2014). EOR is a target for several researches. The ability of EOR to increase oil production from depleted reservoirs cannot be ignored (Bhattacharya et al., 2016; Goodyear, 2016).

EOR method has been investigated on several levels in order to select the best application. The screening criteria of each method depend on the reservoir history (Moreno et al., 2014). Several EOR methods have been introduced including thermal EOR and non-thermal methods. Chemical enhanced oil recovery (CEOR) is a nonthermal method; it has shown high applicability in several conditions. Thus, it has been under the spotlight for decades. Chemical flooding works by injecting chemicals not existing in reservoir to improve the sweep efficiency. Several chemicals have been introduced such as polymer, surfactant, alkalines and recently nanoparticles (Kim et al., 2017; Sabzabadi et al., 2014; Thomas, 2006).

1.1 Chemical ASP flooding

ASP is a combining tertiary oil recovery method like alkaline, surfactant and polymer flooding in order to achieve the synergetic effect out of the different impacts which are caused by these chemicals, affect oil and water filtration in the reservoir and increase oil recovery

1.1.1 The function of alkaline, surfactant, and polymer during ASP

In EOR, flooding is based on the injection of water or another liquid, such as an alkaline solution, a surfactant solution etc., into the formation and during the oil under the driving force of pressure gradient.

ASP flooding uses the benefits of the three flooding methods simultaneously (alkaline, surfactant, and polymer-flood). (Kudaibergenov, 2015)

1.1.2 Oil recovery mechanisms in ASP flooding

Mechanisms in alkaline flooding are complicated. There are at least eight postulated recovery mechanisms which include emulsification with entrainment, emulsification with entrapment, emulsification with coalescence, wet ability reversal, wet ability gradients, oil-face swelling, disruption of rigid films, and low interfacial tensions.

the most important factor for al-kali flooding. Furthermore, it states that the chemicals produced by in -situ saponification increase oil recovery.

Surfactants are considered to be good enhanced oil recovery agents since they can significantly lower the interfacial tension and alter wetting properties

Polymer is applied to change the mobility ratio to a favorable number since the injected fluid would not bypass the displaced fluid, i. e. crude oil in reservoir. Changing the properties of the crude oil or the permeability of the reservoir is not feasible from economic and technical points. Most mobility control methods change the properties of injected fluid. Polymer can significantly increase the apparent viscosity of the injected fluid (Kudaibergenov, 2015)

1.2 Chemical EOR surfactant

1.2.1 surfactant definition

Some compounds like short chain fatty acids, are amphiphilic or amphipathic i e, they have one part that has an affinity for nonpolar media and one part that has affinity for polar media, these molecules form oriented monolayers at interfaces and show surface activity (i. e they lower the surface or interfacial tension of medium in which they are dissolved).

In some usage surfactant are defined as molecules capable of associating to form micelles.

1.3 Problem statement

Previous studies in screening of EOR methods for the Sudanese oil fields show that Heglig main oil field is suitable to candidate the stock tank oil original in place STOOIP (577.95 MMSTB), where only 22.2% was produced through naturally depletion (Husham A. Ali, 2015)

1.4 Objectives

The objective of this research is to design the chemical EOR pilot in Heglig Main oil field through a dynamic simulation modeling study; this model was constructed and run in advanced Chemical simulation software. The scope of work of the pilot study is:

1. To study the possibility to increase the recovery factor for Heglig.
2. To Design an ASP Flooding model in a well pair in Heglig.
3. To make comparison process between two cases, before and after injection case
4. To obtain pilot results in order to further refine to the chemical EOR full-field model.

1.5 About the field

the greater Heglig oilfield is located in southeast and middle of block 2B, Muglad basin. The oil field consist of 8 major fields, namely heglig main, Toma, EL Bakh, EL Fula, 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 MMSTP which is 63.2 % of the total STOIP of greater heglig (29th DTR, GNPOC, 2012)

Heglig main started production in June 1999; the main reservoir are Aradeba main, Bentiu1, Bentiu2, and Bentiu3 figure (1.1) and figure (1.2) is illustrates the structure Map of Heglig Main-Bantiui-1 formation, the drive mechanism is Bottom of edge water with moderate to strong aquifer strength, the critical challenges of development is high water cut and most of remaining oil is located at lower quality reservoirs, the current depletion strategy is adopting selective interval for a new infill wells whereas conducting sidetrack of workover for the existing wells, the previous studies in screening of EOR methods for Sudanese oil fields show that Heglig main

oil field (B1a) is suitable candidate for EOR chemical methods(29th DTR, GNPOC, 2012)

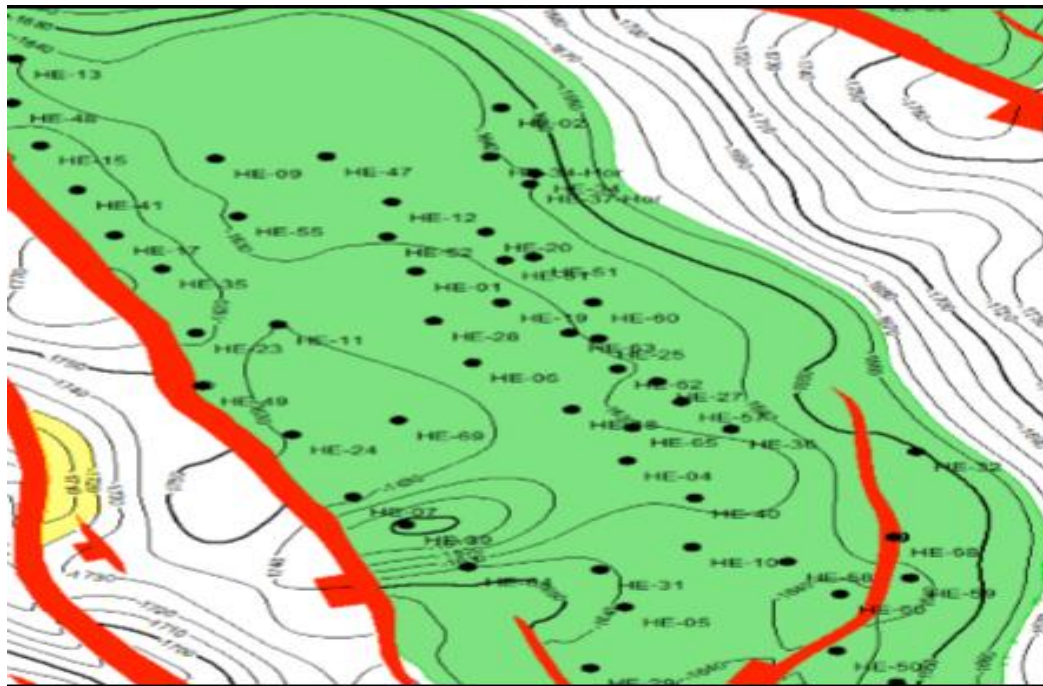


Fig 1 - 1 structure Map for Heglig main Bantue-1 (Husham A. Ali, 2015)

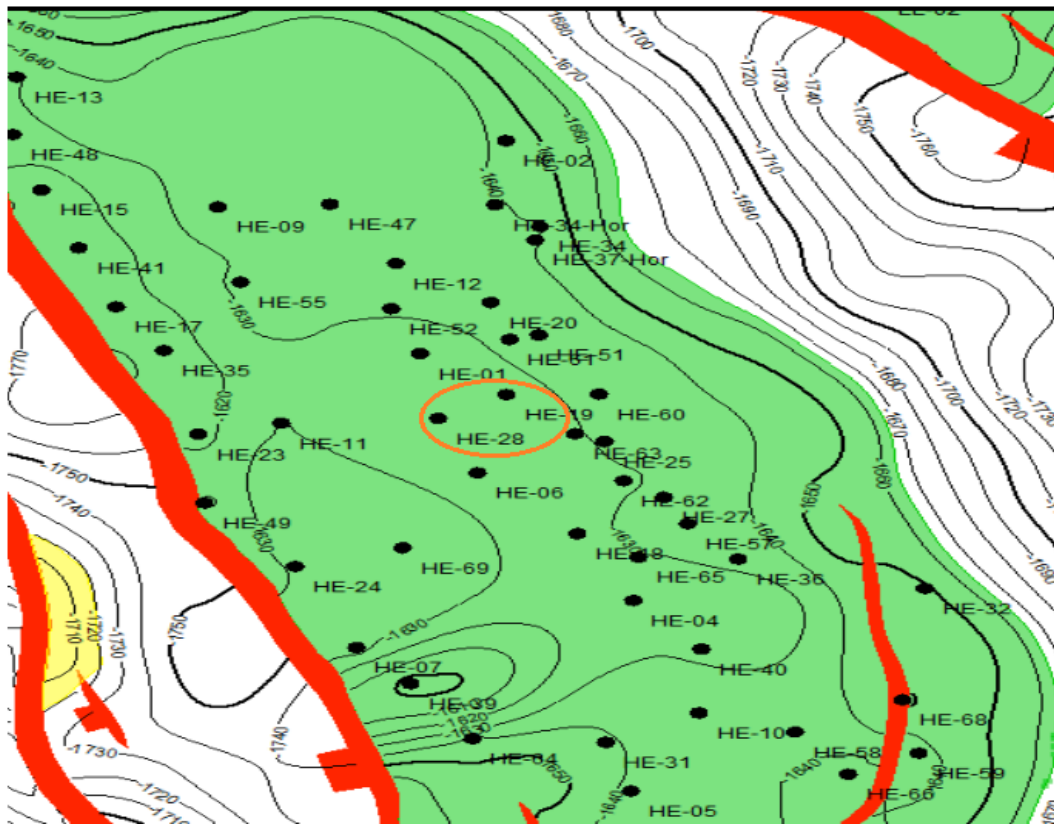


Fig 1 - 2 vertical wells produced from B1Aa and lower zone in Helig main. (Husham A. Ali, 2015)

Chapter 2

Theoretical background and Literature review

2.1 Types of EOR Techniques

There are three main types of EOR, including chemical flooding, gas injection and thermal recovery. Increasing the cost of development alongside the hydrocarbons brought to the surface, producers do not use EOR on all wells and reservoirs. The economics of the development equation must make sense. Therefore, each field must be heavily evaluated to determine which type of EOR will work best on the reservoir. This is done through reservoir characterization, screening, scoping, and reservoir modeling and simulation.

2.1.1 Thermal Recovery

Thermal recovery introduces heat to the reservoir to reduce the viscosity of the oil. Many times, steam is applied to the reservoir, thinning the oil and enhancing its ability to flow. First applied in Venezuela in the 1960s, thermal recovery now accounts for more than 50% of applied EOR in the US.

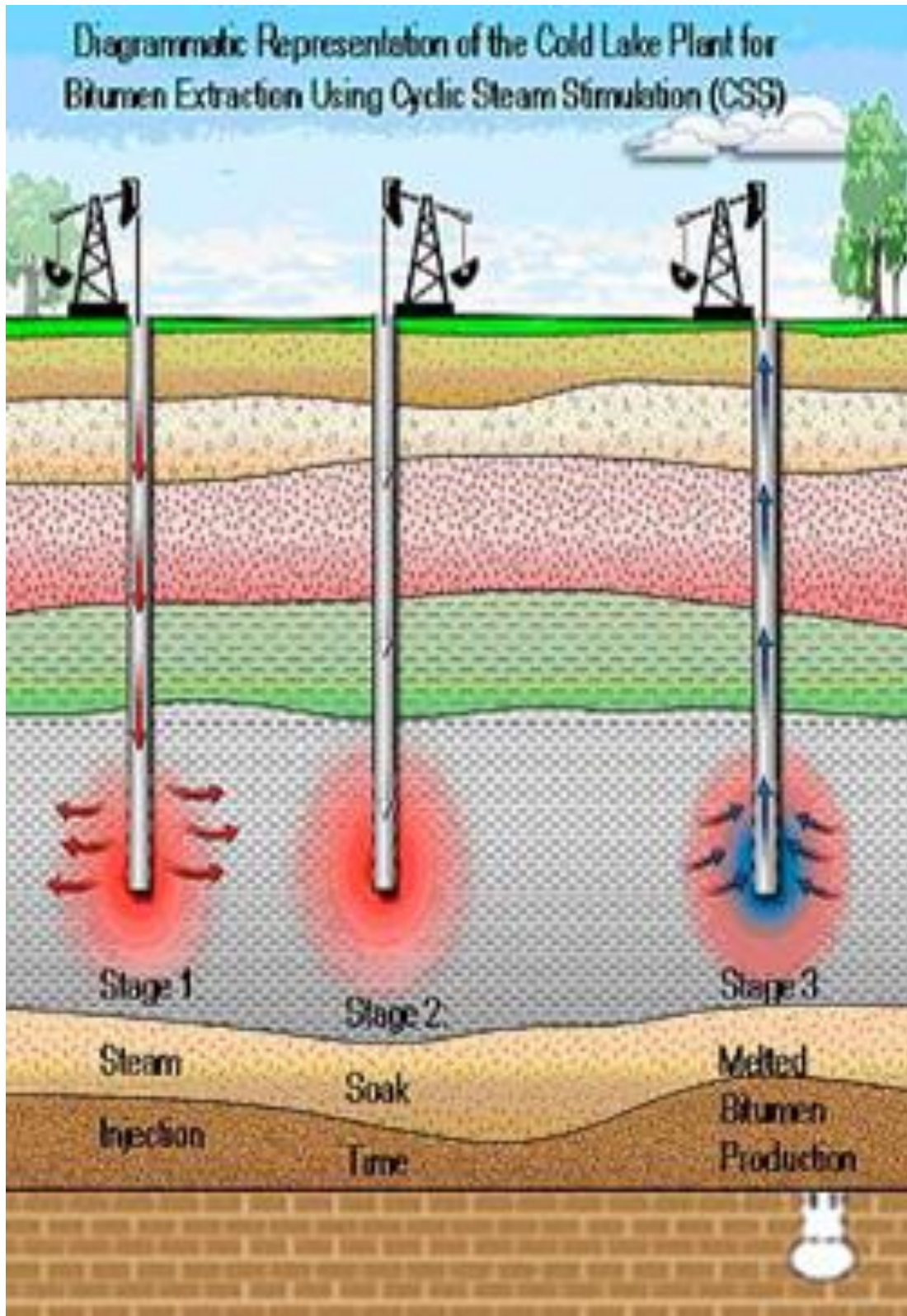


Fig 2- 1 Thermal Recovery Source: Alberta Geological Survey

2.1.2 Chemical Injection

Chemical injection EOR helps to free trapped oil within the reservoir. This method introduces long-chained molecules called polymers into the reservoir to increase the efficiency of water flooding or to boost the effectiveness of surfactants, which are cleansers

that help lower surface tension that inhibits the flow of oil through the reservoir. Less than 1% of all EOR methods presently utilized in the US consist of chemical injections.

2.1.3 Gas Injection

Gas injection used as a tertiary method of recovery involves injecting natural gas, nitrogen or carbon dioxide into the reservoir. The gases can either expand and push gases through the reservoir, or mix with or dissolve within the oil, decreasing viscosity and increasing flow.

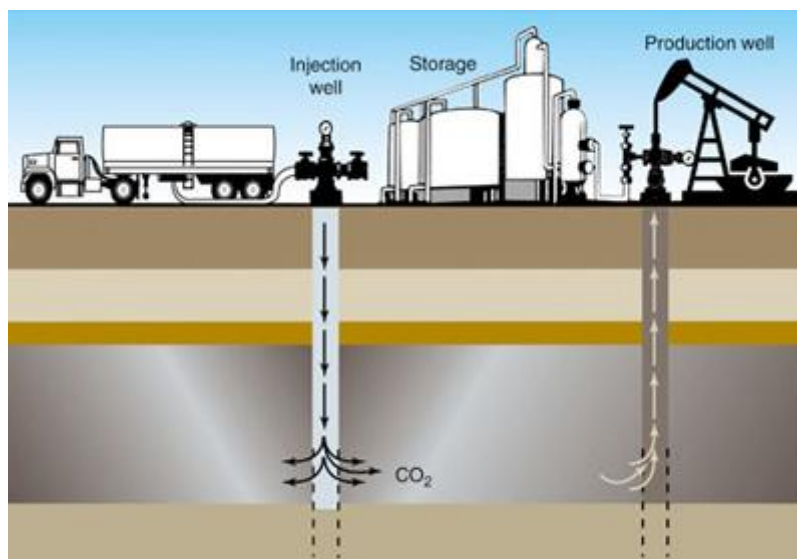


Fig 2- 2 Carbon Dioxide EOR Source: Lawrence Livermore National Laboratory

2.2 Using Enhanced Oil Recovery Methods

Petroleum companies and scientists look to EOR for its potential to prolong the life of wells in proven or probable oil fields. Proven reserves are those with a greater than 90% chance that oil will be recovered, and probable reserves have a more than 50% chance of recovering petroleum.

Unfortunately, EOR techniques can produce negative environmental side effects, such as causing harmful chemicals to leak into the groundwater. One **recent** technique that might help reduce these environmental risks is called plasma pulsing. Developed in Russia, plasma pulse technology involves radiating oil fields with low-energy emissions, thereby lowering their viscosity much like conventional EOR techniques.

Because plasma pulsing does not require injecting gases, chemicals, or heat into the ground, it may prove to be less environmentally harmful than the other current methods of oil recovery. (source: Europe's leading offshore pipeline technology conference).

2.3 Chemical surfactant properties

The unusual properties of aqueous surfactant solutions can be ascribed to the presence of hydrophilic head group and hydrophobic chain (or tail) in the molecules.

2.3.1 The hydrophobic effect and micelle formation

In aqueous solutions dilute concentrations of surfactant act much as normal electrolytes. but at higher concentrations very different behavior result. this behavior explained in term of the formation of organized aggregates of large number of molecules called micelles.

2.3.2 Critical micelle concentration

It is well known that the physicochemical properties of surfactant very markedly above and below specific surfactant concentration.

below CMC value, the physicochemical properties of ionic surfactant like SDS.

Above CMC value these properties change dramatically indicating highly cooperative association process is taking place.

CMC values. Some CMC values for low electrolyte concentration in room temperature are

Anionics	$10^{-3} - 10^{-2} \text{ M}$
Amphoteric	$10^{-3} - 10^{-1} \text{ M}$
Cationics	$10^{-3} - 10^{-1} \text{ M}$
Nonionics	$10^{-5} - 10^{-4} \text{ M}$

2.3.3 The krafft point

The solubilities of micelle –forming show strong increase above certain temperature, termed the krafft point (T_k). this is explained by the fact that the single surfactant molecules have limited solubility whereas the micelles are very soluble.

Below krafft point the solubility of surfactant is too low for micellization so solubility alone determines the surfactant monomer concentration. As temperature increase the solubility is increase until at T_k the CMC is reached.

At this temperature relatively large amount of surfactant can be dispersed in micelles and solubility increase greatly

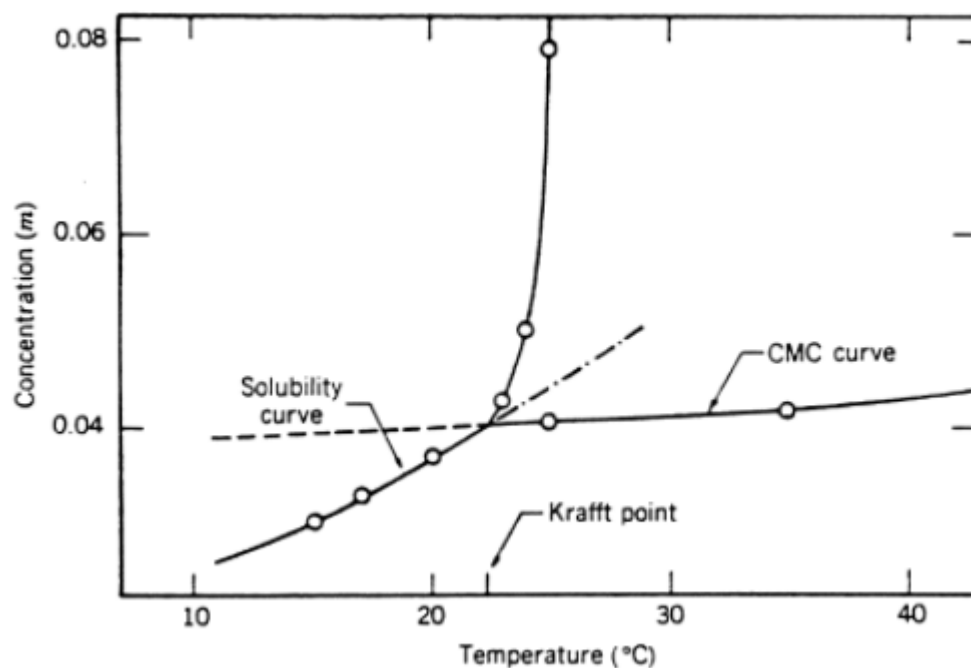


Fig 2- 3 Example of phase behavior diagram for surfactant in aqueous solution showing the cmc and krafft points, (from Shinoda et al,{11}. Copyright 1963. Academic press, New York.)

2.3.4 Analysis

Numerous methods have been developed for the quantitative determination of each class of surfactant.

The analysis of commercial surfactants is greatly complicated by the fact that these products are mixtures. They are often comprised of range of molar mass structures of a given structural class

2.3.5 Surface elasticity

As the surfactant adsorbs at an interface the interfacial tension decrease (at least up to the CMC), a phenomenon termed Gibbs effect

If a surfactant stabilized film undergoes a sudden expansion, the immediately expanded portion of film must have a lower degree of surfactant adsorption than unexpanded portions because the surface area has increased. this cause an increased local surface tension which produces immediate contraction of the surface.

The transport of bulk liquid due to surface tension gradients is termed Marangoni effect.

In foams the Gibbs_Marangoni effect provides a resisting force to the thinning of liquid films.

The Gibbs_Marangoni effect only persist until the surfactant adsorption equilibrium is reestablished in the surface

A process that may take place within second or over period of hours.

At equilibrium the surface elasticity or surface dilational elasticity is defined by

$$E = \frac{dy}{d \ln A} \quad (3.1)$$

E_c surface elasticity.

Y surface tension.

A geometric area of the surface.

2.3.6 Surface Rheology

Surface rheology deals with dynamic behavior of surface in response of the stress that is placed on the surface, tow viscosities are defined within the interface.

Shear viscosity

For surfactant monolayer, the surface shear viscosity is analogous to the three dimensional shear viscosity, the rate of yielding of layer of fluid due to an applied shear stress.

Dilational viscosity

The surface dilational viscosity express the magnitude of the viscous forces during rate expansion of surface element. A surfactant monolayer can be expanded or compressed over wide area range thus, the dynamic surface tension experienced during rate dependent surface expansion in the resultant of the surface dilational viscosity. (source: surfactants fundamentals and applications in the petroleum industry by laurer L. Schramm)

2.4 the systematic Classifications of surfactants

Surface active agents (Surfactants) may be classified in several ways, depending on needs and intentions of the people involved, one of the more common schemes relies on classification by application, surfactant may be classified as emulsifiers, foaming agents, wetting agents, dispersants.

Surfactant may also be generally classified according to some physical characteristics such as primarily water or oil solubility or stability in harsh environment.

In the bulk aqueous phase, surfactants form masses, such as micelles, where the hydrophobic tails form the core and the hydrophilic heads are immersed in the surrounding liquid. Other types of structures can also be formed, such as spherical micelles or lipid bilayers. The shape of the molecules depends on the balance in size between hydrophilic head and hydrophobic tail. A measure of this is the HLB, Hydrophilic-lipophilic balance. Higher HLB surfactants (>10) are hydrophilic (“water loving”) and form O/W (Oil-in-water) emulsions. Lipophilic surfactants possess low HLB values (1-10) and form W/O (water-in-oil) emulsions. Dish detergents, surfactants for emulsion polymerization, and the following example (SLS = Sodium Lauryl Sulfate) are high HLB surfactants.

The dynamics of surface-active agent adsorption is of great importance for practical applications such as in emulsifying or coating processes as well as foaming, where bubbles or drops are rapidly generated and need to be stabilized.

As the interface is created, the adsorption is limited by the diffusion of the surfactant to the interface, which can result in the kinetics being limited. These energy barriers can be due to steric or electrostatic repulsions; steric repulsions form the basis of how dispersants function. Surface rheology of surfactant layers, are important to the stability of foams and emulsions.

Most surfactants' "tails" are fairly similar, consisting of a hydrocarbon chain, which can be branched, linear, or aromatic. Fluor surfactants have fluorocarbon chains. Siloxane surfactants have siloxane chains. Recent advances in surfactant technology has seen the development of mixed chains or/and complex structures.

There are 4 types of surfactants with a brief review of each as follows. These classifications are based upon the composition of the polarity of the head group: nonionic, anionic, cationic, amphoteric.

non-ionic surfactant

has no charge groups in its head. The head of an ionic surfactant carries a net charge. If the charge is negative, the surfactant is more specifically called anionic; if the charge is positive, it is called cationic. If a surfactant contains a head with two oppositely charged groups, it is termed zwitterionic. Commonly encountered surfactants of each type are listed as follows. A complete compendium can be found on ULProspector.com.

Nonionic surfactant

Many long chain alcohols exhibit some surfactant properties. Some examples of non-ionic surfactants include:

octane sulfonate (PFOS), linear alkyl benzene sulfonates (LABs) and perfluoro butane sulfonate, as well as alkyl-aryl ether phosphates. More specialized species include sodium lauroyl sarcosinate and carboxylate-based fluoro surfactants such as per fluoro nonanoate, per fluoro octanoate (PFOA or PFO).

Table 2 - 1: Nonionic surfactant Examples (Hirsch, 2015)

Trade name	Structure/name	Applications
Triton™ X-100	Polyoxyethylene glycol octylphenol ethers: C ₈ H ₁₇ -(C ₆ H ₄)-(O-C ₂ H ₄) ₁₋₂₅ -OH	Wetting agent – coatings
Nonoxynol-9	Polyoxyethylene glycol alkylphenol ethers: C ₉ H ₁₉ -(C ₆ H ₄)-(O-C ₂ H ₄) ₁₋₂₅ -OH	Spermicide
Polysorbate	Polyoxyethylene glycol sorbitan alkyl esters	Food ingredient
Span®	Sorbitan alkyl esters	Polishes, cleaners, fragrance carriers
Poloxamers, Tergitol™, Antarox®	Block copolymers of polyethylene glycol and polypropylene glycol	Various

Anionic surfactant

Anionic surfactants contain anionic functional groups at their head, such as sulfonate, phosphate, sulfate and carboxylates. Alkyl sulfates include ammonium lauryl sulfate, sodium lauryl and the related alkyl-ether sulfates sodium laureth sulfate, also known as sodium lauryl ether sulfate (SLES), and sodium myreth sulfate. These are the most common surfactants and comprise the alkyl carboxylates (soaps), such as sodium stearate. The stearates comprise >50% of the global usage of surfactants. Many of these find utilization in emulsion polymerization. Other anionic surfactants include dioctyl sodium sulfosuccinate (DOSS), per fluoro

Table 2-2 Anionic surfactant classifications Examples (Hirsch, 2015)

Trade name	Structure/name	Applications
PENTEX® 99	Diocetyl sodium sulfosuccinate (DOSS)	Wetting agent – coatings, toothpaste
PFOS	Perfluorooctanesulfonate (PFOS)	Scotchguard™, Skydrol™
Calsoft®	Linear alkylbenzene sulfonates	Laundry detergents, dishwasher detergents
Texapon®	Sodium lauryl ether sulfate	Shampoos, bath products
Darvan®	Lignosulfonate	Concrete plasticizer, plasterboard, DMSO
N/A	Sodium stearate	Handsoap, HI&I productsv

Cationic surfactant

Cationic surfactants are comprised of a positively charged head. Most of cationic surfactants find use as anti-microbials, anti-fungals, etc. in HI&I (Benzalkonium chloride (BAC), Cetylpyridinium chloride (CPC), Benzethonium chloride (BZT). The cationic nature of the surfactants is not typically consistent with the world of non-ionic and anionic charges, and they disrupt cell membranes of bacteria and viruses. Permanently charged quaternary ammonium cations include: Alkyltrimethylammonium salts: cetyl trimethylammonium bromide (CTAB) and cetyl trimethylammonium chloride (CTAC).

Zwitterionic surfactants

Zwitterionic (amphoteric) surfactants have both cationic and anionic centers attached to the same molecule. The anionic part can be variable and include **sulfonates**, as in the sultaines CHAPS (3-)

(Cholamidopropyl)dimethylammonio]-1-propanesulfonate). Betaines such as cocamidopropyl betaine have a carboxylate with the **ammonium**. The cationic part is based on primary, secondary, or tertiary amines or quaternary ammonium cations. Zwitterionic surfactants are often sensitive to pH and will behave as anionic or cationic based on pH. Fast dry (“coacervation”) latex traffic paints are based on this concept, with a drop in pH triggering the latex in the paint to coagulate.

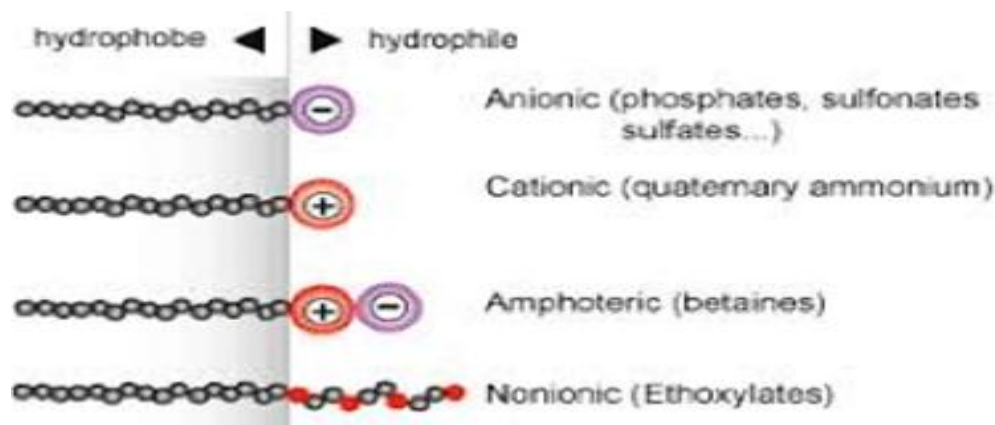


Fig 2- 4 Representation of the 4 types of surfactant. Source: Incline. gr

In a future article, a specific type of surfactant will be presented. Dispersants are surface-active substances added to a suspension, usually a colloid, to improve the separation of particles and to prevent settling or clumping.

(source: chemistry and technology of surfactants by Richard J. Farn)

Chemical process focus on decreasing the oil-water interfacial tension to very low values, or removal of interface altogether, in term of oil produced at present, chemical process only of the order of 10% of total EOR picture, process in which low concentration surfactant solutions (of the order of 1% or less) are injected are commonly referred to surfactant as process, the term micro-emulsion or micellar flood used for process in which A concentrated surfactant solution (of 10% or more) and a co-surfactant (usually high molecular alcohol) is injected into reservoir, (J.A BOON 1984)

The ASP process, as the name suggests , is a combination of the three process namely alkaline , surfactant and polymer flooding in which the three slugs , are used in sequence , alternatively the three fluid could be mixed together and injected as single slug , the objective of the ASP flooding process is to reduce the amount of chemical consumed per unit volume of oil required and invariable a reduction in cost . (Faroug Ali , et al , 2001)

The Greater Heglig Oilfield is located in the southeast and middle of block 2B, Muglad Basin. The oilfield consist of 8 major field, namely Heglig main, 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 Great Heglig. (29th DTR, GNPOC, 2012)

In 2012 Ridha Gharbi, Abdalla Alajmi and Meshal Algharaib from Kuwait University developed full field model for middle eastern sandstone reservoir. A sector model was then constructed and used to define new management and production strategies. The project profitability and economic limits for different design parameters were examined in order to optimize the remaining oil recovery from this reservoir using a suitable EOR method. (R. GHARBI, A. ALAJMI, M. ALGHARAIB 2012)

Heglig Main started production in June 1999; the main reservoir are Aradeiba main, Bentiu-1, Bentiu and Bentiu-3 figure 1 illustrates the structure map of Heglig main Bentiu-1 formation, the drive mechanism is bottom and edge water with moderate to strong aquifer strength, the critical challenges of development are high water cut and most of the remaining oil is located at the lower quality reservoir the current depletion strategy is adopting selective interval for the new infill wells were conducting sidetrack or workover for the existing wells the previous studies in screening of EOR methods for the Sudanese oil fields show that Heglig main oil field (Bla) is suitable candidate for EOR chemical methods (29th DTR, GNPOC, 2012)

There are also many studies implemented in chemical surfactant flooding, in 2013 James J. Sheng from Texas University found that Alkaline-surfactant-polymer (ASP) flooding is a combination process in which alkali, surfactant, and polymer are injected in the same slug. Because of the synergy of these three components, ASP is the current worldwide focus of research and field trial in chemical enhanced oil recovery (EOR). This study provides a comprehensive review of the ASP process. The reviewed topics include ASP synergy and its EOR mechanisms Screening Criteria Laboratory work Numerical simulation work Summary of pilots and large-scale applications Project economics Chemicals used Water Quality Mobility control requirement Problems associated with ASP flooding and possible solutions (JAMES J. SHENG 2013).

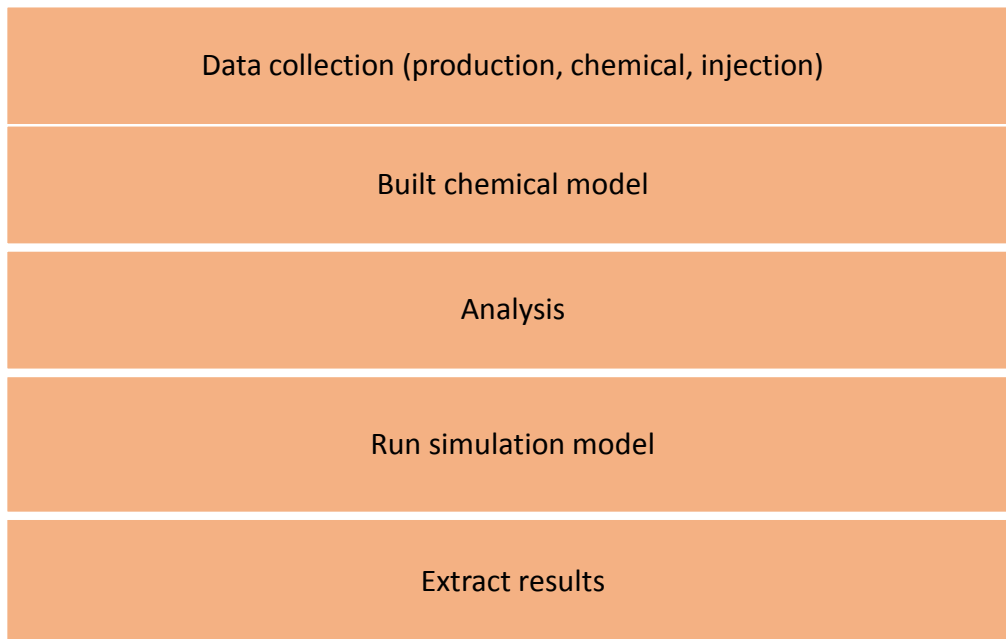
In 2015 Husham A. Ali making study, this study focused on the selection of suitable area and wells for chemical enhanced oil recovery (Alkaline- Surfactant-

Polymer (ASP)) pilot test and design the optimum injection parameter to maximize the oil recovery from Heglig main oil field in Sudan. From production profile optimum average oil rate option has been selected from three options (HUSHAM A. ALI 2015)

Chapter 3

Methodology

The reservoir data and production data of Heglig main oil field had been collected and used to analyze the effect of ASP flooding in the field and to design the optimum injection and production parameters, in order to increase the recovery factor. The analysis steps are summarized below:



ASP's ability to increase oil recovery by improving the sweep efficiency and reducing residual oil saturation in the reservoir is extremely valuable. However, the complexity of the process requires significant planning before the process can be carried out in the field. The new ASP process wizard in stars, our Equation-of-State (EoS) compositional simulator, allows users to easily set up an ASP process in their reservoir.

This research shows how to use CMG's ASP process wizard to plan and set up an ASP process in a reservoir, easily and accurately. Learn how to build an ASP dataset, match ASP core flood data, upscale to a field-scale model with all the important ASP mechanisms being modelled, plus

Saponification and salinity gradient optimization

Micro-emulsion viscosity

3.1 Equations used in model

A conservation equation is constructed for each component of a set of identifiable chemical components that completely describe all the fluids of interest. All conservation equations are based on a region of interest (with volume V) in which

rate of change of accumulation

= net rate of inflow from adjacent regions

+ net rate of addition from sources and sinks

Each of these three terms will be considered separately, below.

Volumes and Porosities

In each grid cell there are volumes of interest. A superscript “0” indicates the value at the start of the run.

$V_b \equiv$ Current bulk volume

$V_{b0} \equiv$ Initial bulk volume

$V_r \equiv$ Rock volume (solid inert matrix, rock grains)

$V_v \equiv$ Void volume (fluids & variable solids)

$V_s \equiv$ Volume of solid, adsorbed & trapped components

$V_f \equiv$ Volume of fluid phases added together

$V_w \equiv$ Water (aqueous) phase volume

$V_o \equiv$ Oil (oleic) phase volume

$V_g \equiv$ Gas (vapor) phase volume

The current bulk volume is

$$V_b = V_r + V_v \quad (3.1)$$

The current fluid volume is defined as:

$$V_f = V_w + V_o + V_g \quad (3.2)$$

and the current void volume is defined as:

$$V_v = V_b - V_r = V_f + V_s \quad (3.3)$$

Current void porosity is defined as:

$$\phi_v = V_v / V_{b0} \quad (3.4)$$

This is reservoir void porosity since the denominator is initial bulk volume. This should not be confused with true porosity whose denominator would be current bulk volume. At the start of the run, reservoir porosity is equal to true porosity since $V_b = V_{b0}$. With very few exceptions (e.g, geomechanics), porosity used in the simulation is reservoir porosity. Current fluid porosity is defined as

$$\phi_f = V_f / V_{b0} = (V_v - V_s) / V_{b0} = (V_v/V_{b0}) \cdot (1 - V_s/V_v) \quad (3.5)$$

The fraction of V_v occupied by a solid/adsorbed/trapped component i is c_{si}/ρ_{si} , where c_{si} mole concentration of component i in V_v

ρ_{si} molar density of pure component i

The sum of all these component volume fractions is V_s/V_v , and substituting (3.4) gives

$$\phi_f = \phi_v \cdot (1 - \sum c_{si}/\rho_{si}) \quad (3.6)$$

Note that if there is no solid/adsorbed/trapped component, then $V_s = 0$ which makes $V_v = V_f$ and $\phi_v = \phi_f$. (3.7)

In each case void volume is $V_v = \phi_v \cdot V_{b0}$. Note that conservation equations depend on V_v , V_f and V_r but do not depend on bulk volume V_b directly.

The saturations are defined as

$$S_w = V_w/V_f, \quad (3.8)$$

$$S_o = V_o/V_f \quad (3.9), \text{ and}$$

$$S_g = V_g/V_f \quad (3.10), \text{ so}$$

$$S_w + S_o + S_g = 1 \quad (3.11)$$

there is a separate equation for each component in each phase when mass transfer between phases is not assumed to be at instantaneous equilibrium. The equations are

Water Phase

$$\frac{\partial}{\partial t} (\phi_f S_w \rho_w w_i) + \nabla \cdot (\rho_w V_w w_i) = -R_{woi} - R_{wsi} + Q_{wi} \quad i=1,2,3$$

Oil Phase

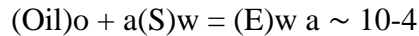
$$\frac{\partial}{\partial t} (\phi_f S_o \rho_o x_i) + \nabla \cdot (\rho_o V_o x_i) = -R_{owi} - R_{osi} + Q_{oi} \quad i=1,2,3$$

Solid Phase

$$\frac{\partial}{\partial t} (\phi_v C_i) = -R_{swi} - R_{soi} \quad i = 1,2,3$$

where $R_{jki} = -R_{kji}$ is the nonequilibrium net mass transfer of component i from phase j to phase k , for $j \neq k$

extra flow equation for surfactant is required, containing a heterogeneous mass transfer source term describing the emulsion creation process. The stoichiometry for the formation process is written as



Estimates of reaction stoichiometry can be obtained by assuming that in a spherical emulsion globule E :

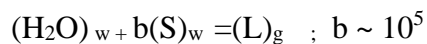
a) The number of oil molecules largely outnumber the surfactant molecules, so that the volume of the globule is basically the volume occupied by the oil molecules

b) The surfactant molecules occupy the surface of the globules. These assumptions can be represented by the equations

$$\frac{\pi}{6} D_d^3 = v_o N_o$$

$$\pi D_d^2 = a_o N_s$$

An average lamella is defined as a combination of water component and aqueous surfactant in a given ratio:



As surfactant is added to the system, residual saturations can decrease and the relative wettability of the phases can change. Ultimately, high surfactant concentrations and the resulting ultra-low interfacial tension values lower the residual saturations

$$N_c = \mu^* v / \sigma$$

N_c : capillary Number

μ : Viscosity (cp)

v : velocity (ft/day)

σ : interfacial tension (dynes/cm)

Table 3 - 1 the relationship between surfactant and alkaline concentrations with IFT

		Wight % 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

the form of the adsorption term in the flow equations

$$\partial / \partial t [\varphi A d_i]$$

simulator adsorption levels are described as moles (or mass) of component i adsorbed per unit volume. A variety of other measures of adsorption levels can be employed, and these must be appropriately converted for simulator input requirements.

Table (3.2): surfactant adsorption values

Enter porosity of laboratory surfactant adsorption sample

0.2494

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

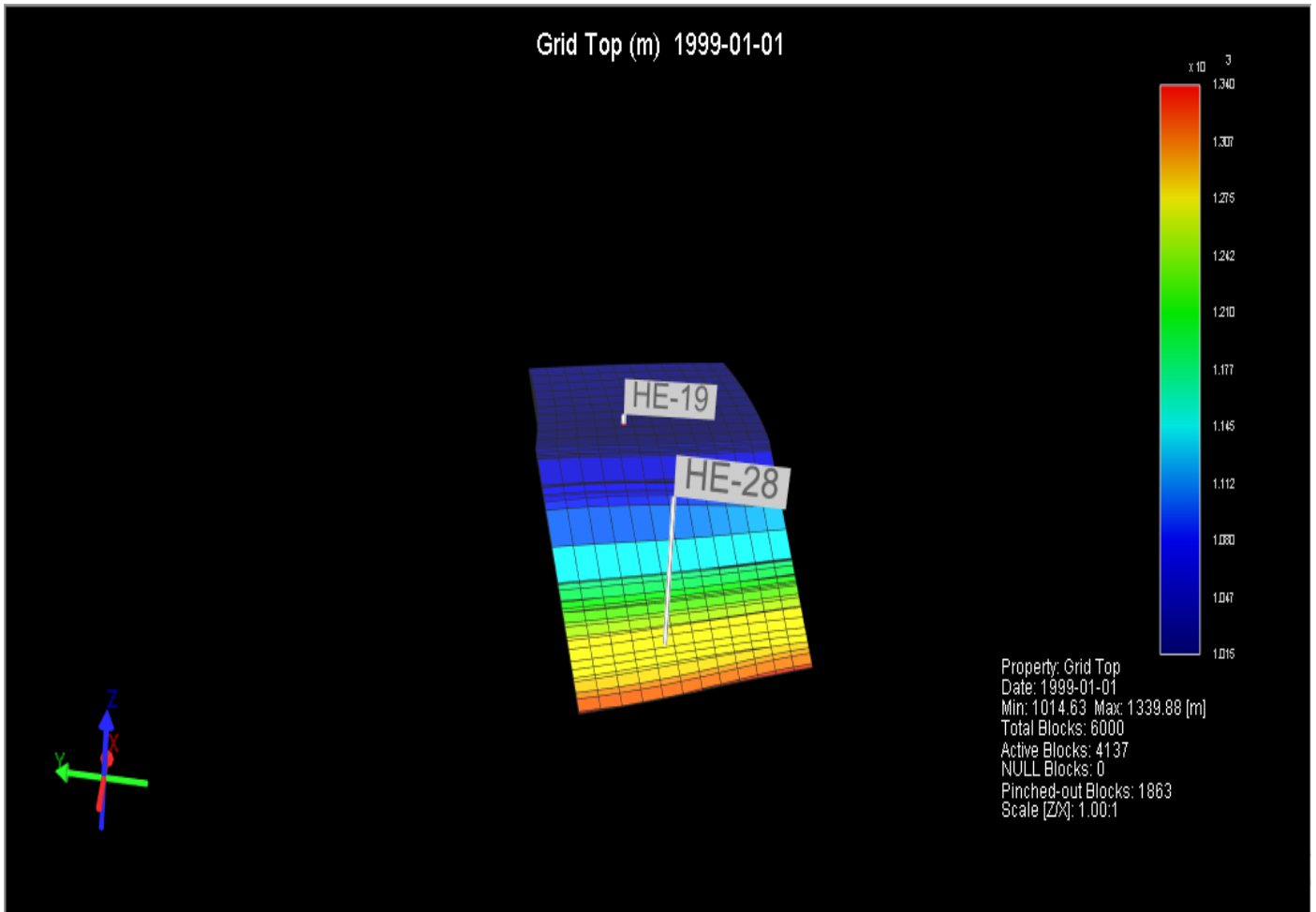


Fig 3 - 1: the grid top and well location in Heglig model in 3D view

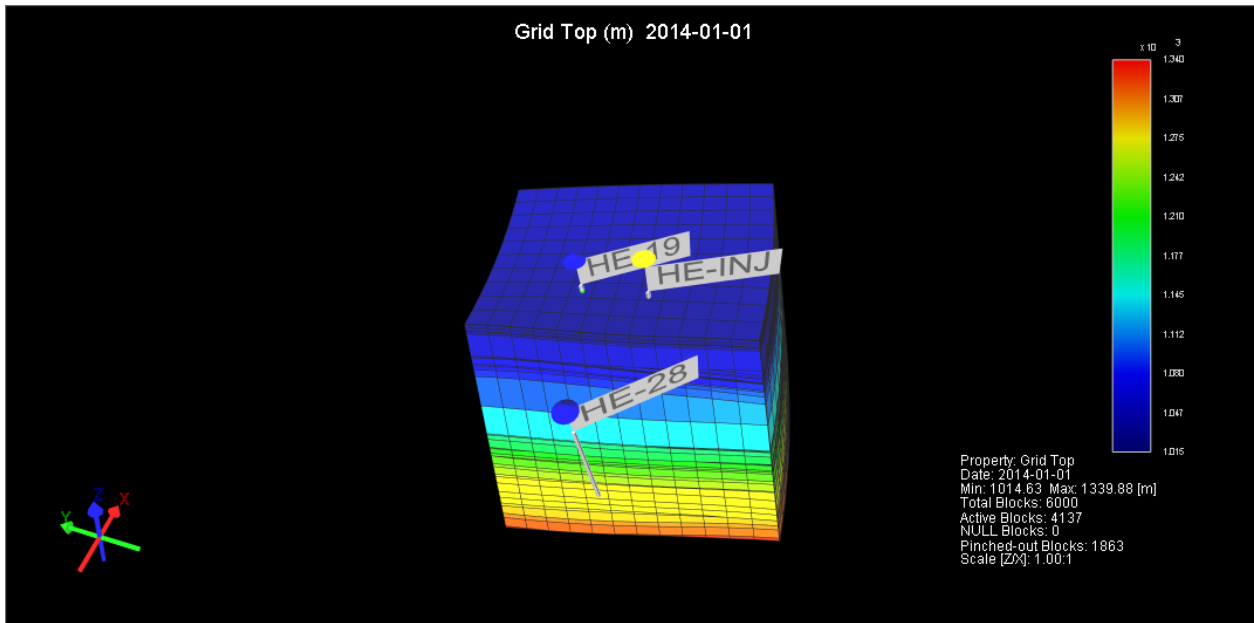


Fig 3 - 2 the grid top and well location in Heglig model in 3D view after adding injection well

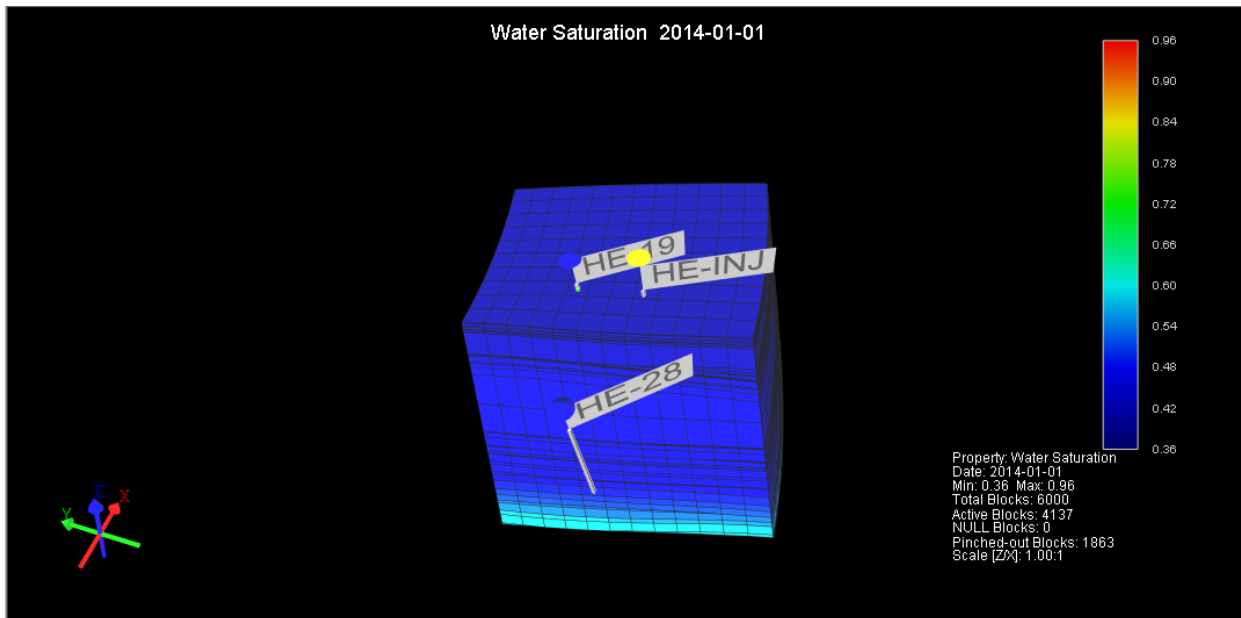


Fig 3 - 3 injected formation after the injection finished and how water saturation is looks like

Chapter 4

Results and discussion

4.1 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

4.2 Original Oil In Place And PVT Data

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

Table 4 - 2 PVT data from Heglig oil field (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 ²)	54.5
Gas specific gravity	1.048
Water Salinity (ppm)	1087

4.3 Heglig CMG Model

4.3.1 Geological Units

The model is composed of 212 layers, divided to 21 zones as illustrated in table (4.3). (abbas, 2015)

Table 4 - 3

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

As a comparison result from after and before injection process show that the oil rate in, HE-19 change after 1-1-2014 from 382.87bbl/day (base case) to 440.286bbl/day (injection case) increment is (57.416bbl/day) show obviously in fig (4.1)

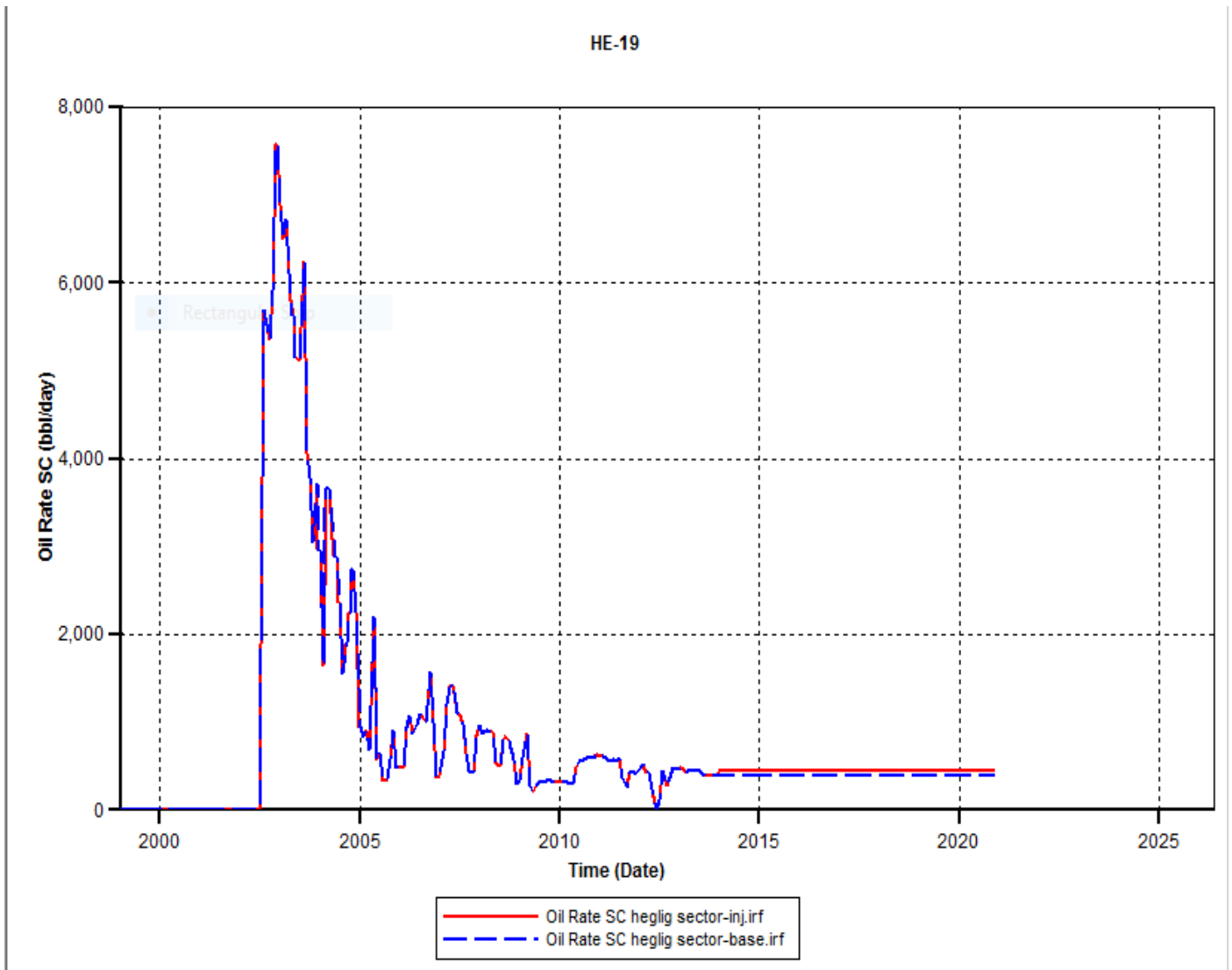


Fig 4 - 1 Comparison between the oil rate of the base case and the injection case for well HE-19

As a comparison result from after and before injection process show that the water cut in, HE-19 change after 1-1-2014 from 0.103561 (base case) to 0.290731(injection case) increment is (0.1873749) show obviously in fig (4.2)

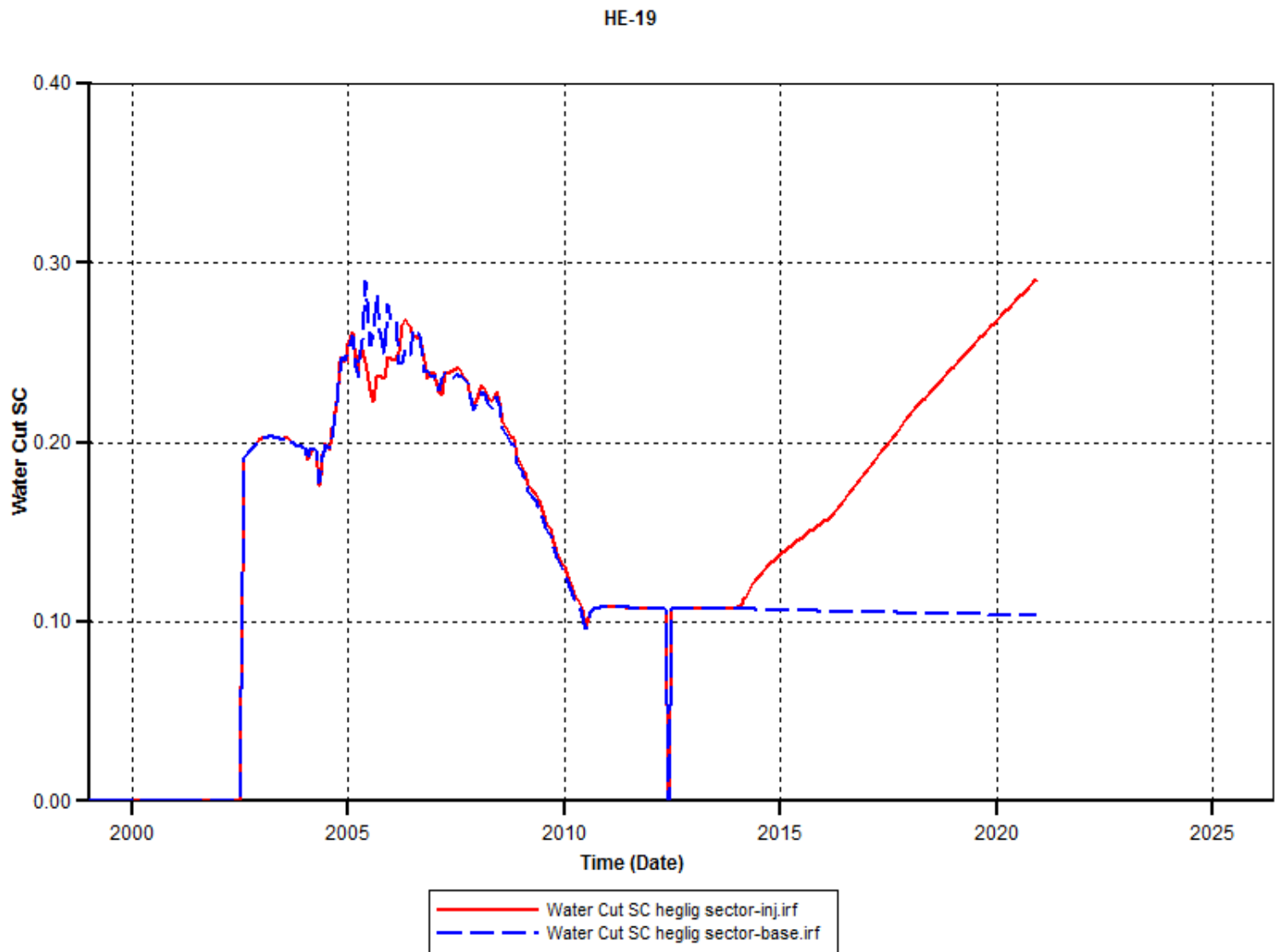


Fig 4 - 2 Comparison between the water cut of the base case and the injection case for well HE-19

As a comparison result from after and before injection process show that the oil rate in, HE-28 change after 1-1-2014 from 191.41bbl/day (base case) to 444.07bbl/day (injection case) increment is (252.66bbl/day) show obviously in fig (4.3)

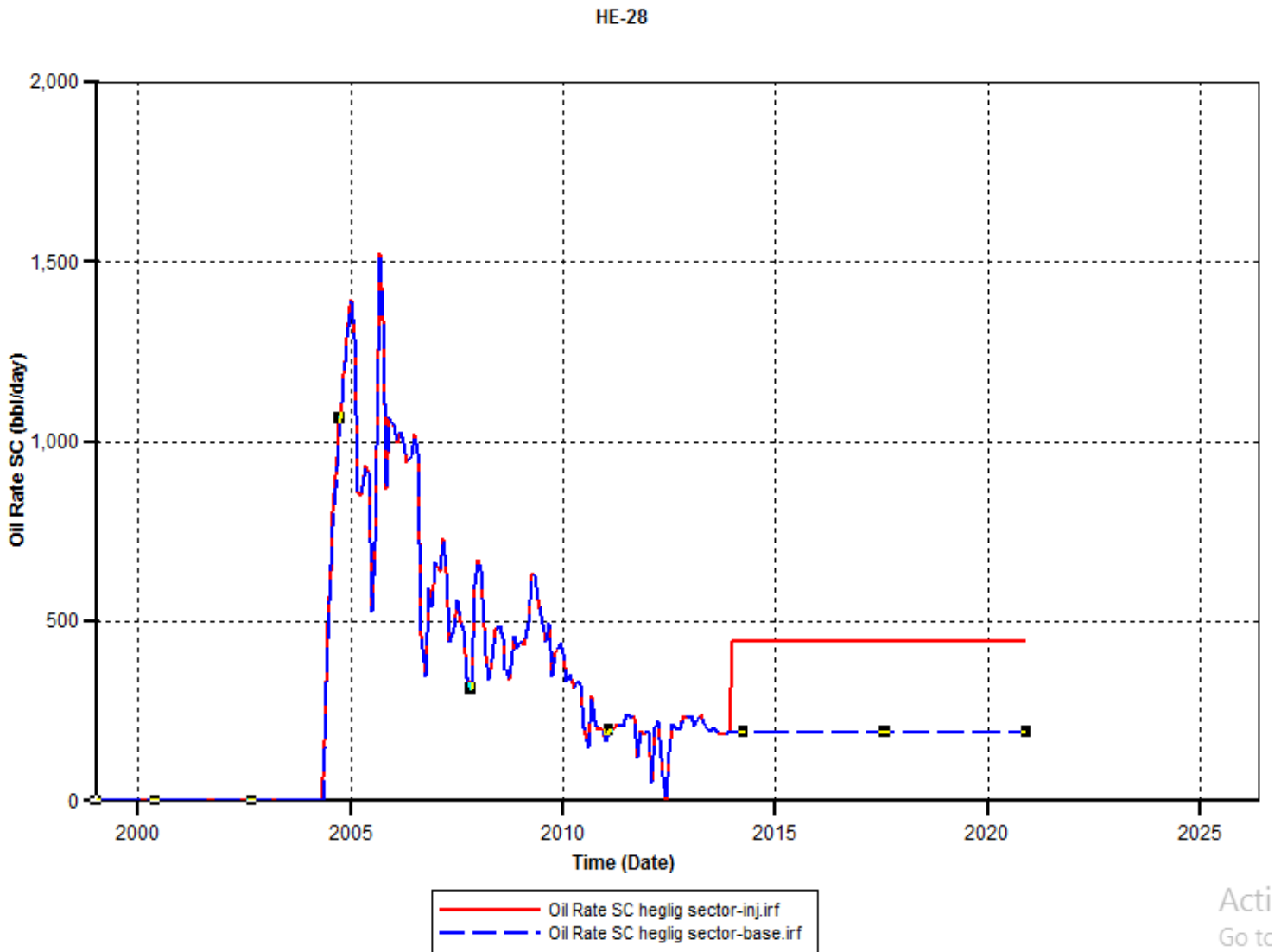


Fig 4 - 3 Comparison between the oil rate of the base case and the injection case for well HE-28

As a comparison result from after and before injection process show that the water cut in HE-28 change after 1-1-2014 from 0.660682 (base case) to 0.77568 (injection case) increment is (0.114999) show obviously in fig(4.4)

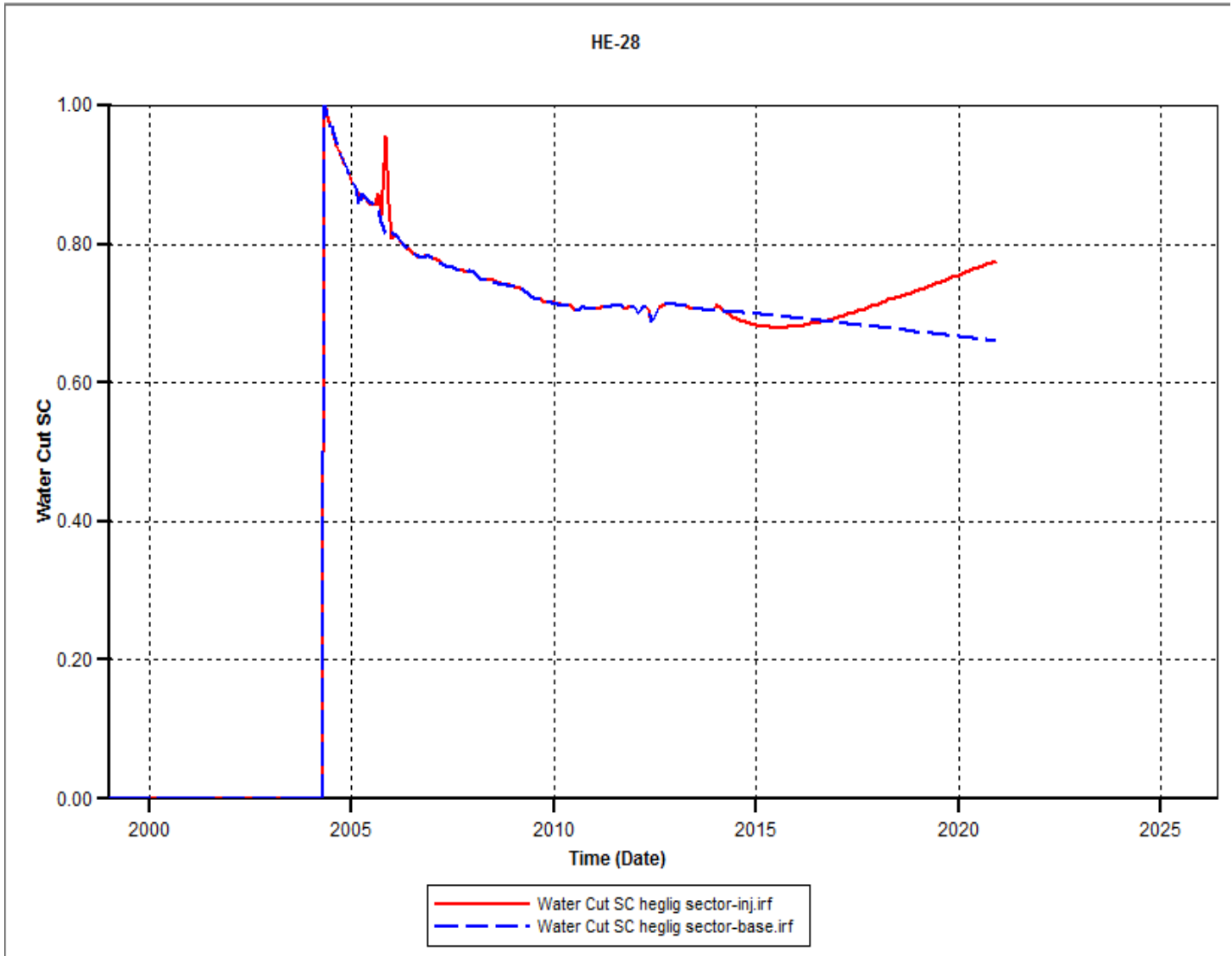


Fig 4 - 4 Comparison between the water cut of the base case and the injection case for well HE-28

As a comparison result from after and before injection process show that the recovery factor entire change after 1-1-2014 from 4.67447 (base case) to 5.08527(injection case) increment is (0.4108) show obviously in fig (4.5)

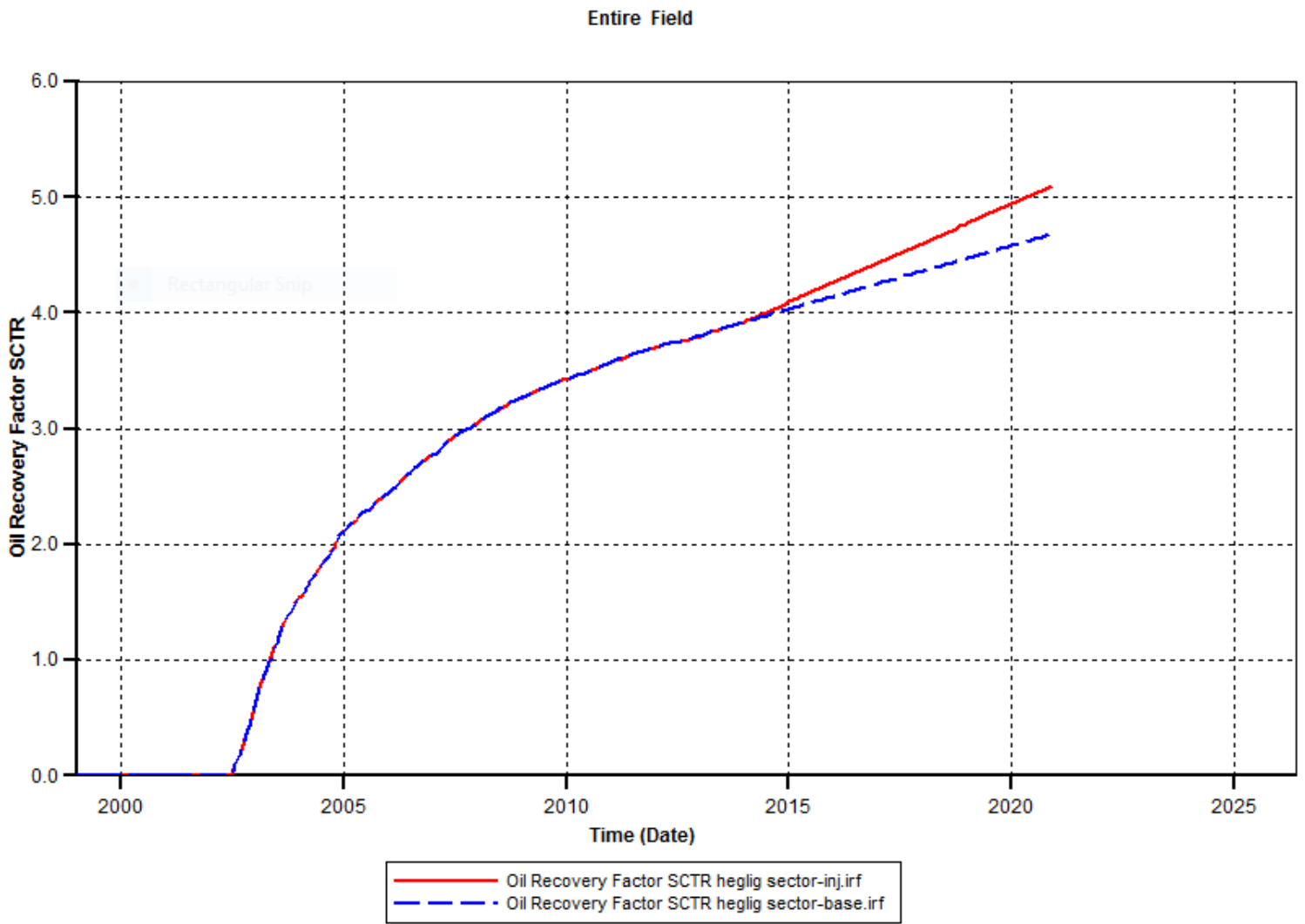


Fig 4 - 5 Comparison between the oil recovery factor of the base case and the injection case for entire field.

As result for injection process, observes of injection effect on water rate in HE-19 as increasing from 53.2238bbl/day at 1\1\2014 (break through time) to 180.475bbl/day at 1/12/2020 as show in below fig

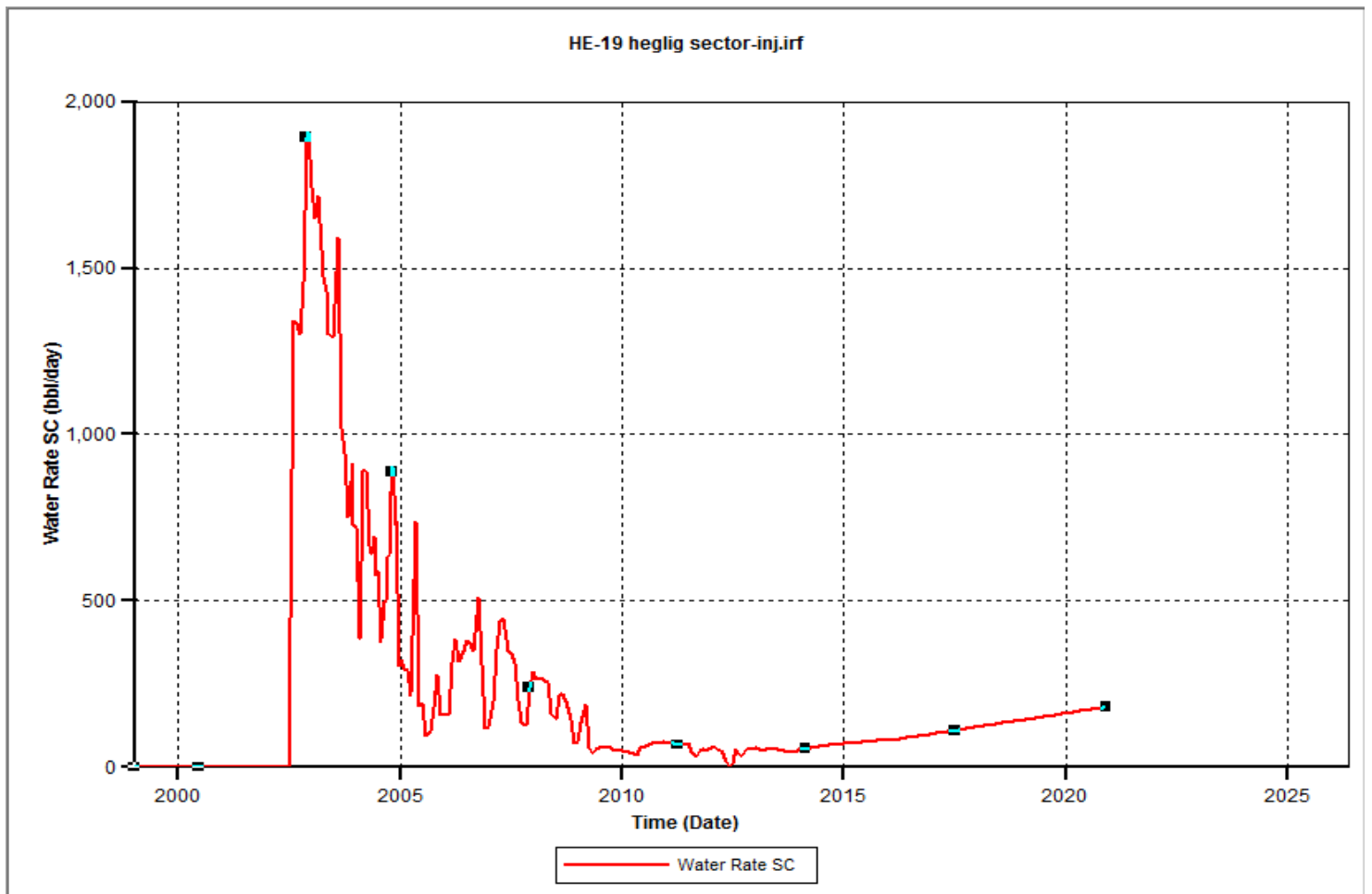


Fig 4 - 6 water rate in HE-19 after injection case

As result for injection process, observes of injection effect on well bottom hole pressure in HE-19 as increasing from 155.628psia at 1\1\2014 (break through time) to 191.495psia at 1/12/2020 as show in below fig

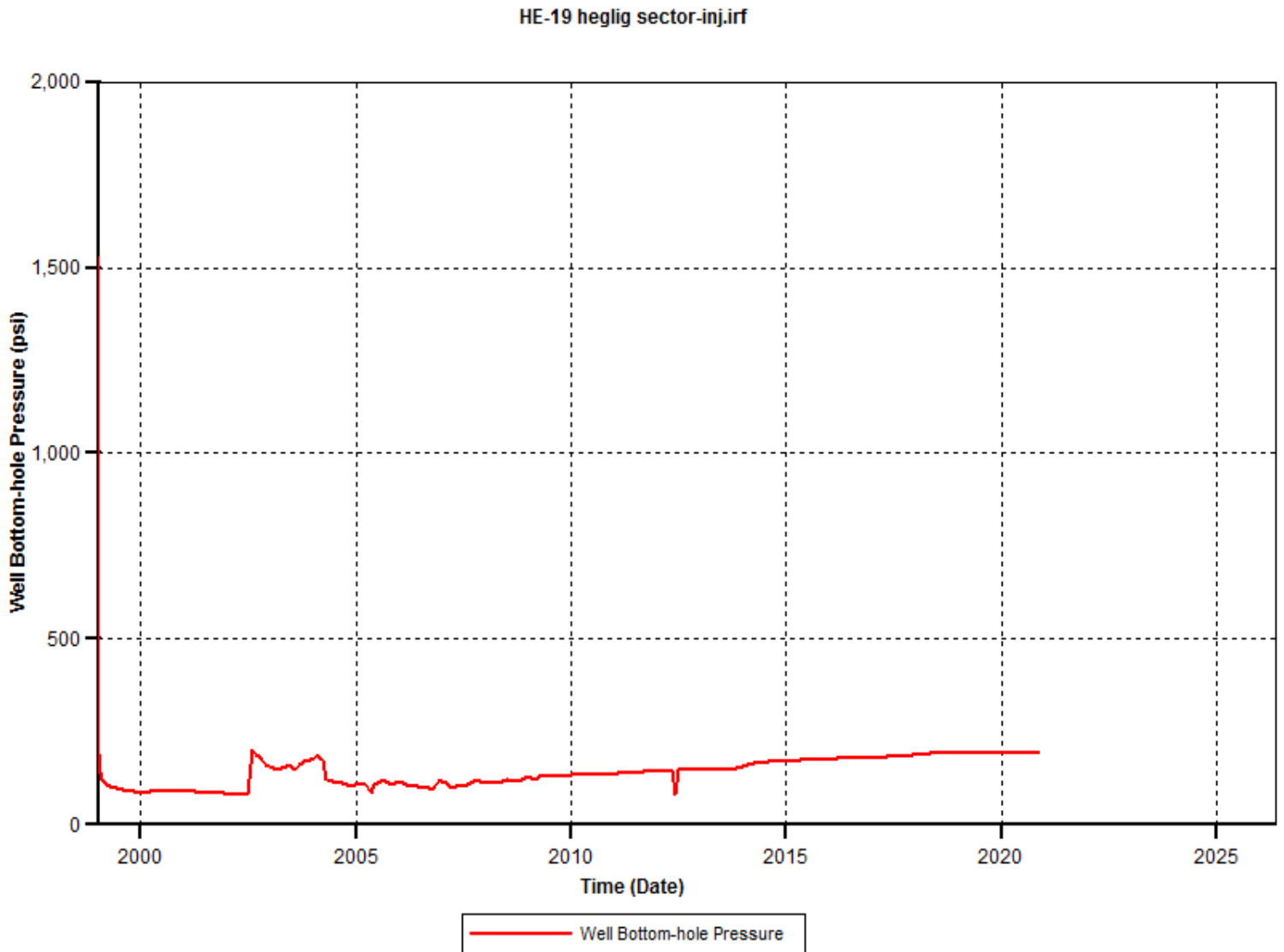


Fig 4 - 7 well bottom hole pressure in HE-19 after injection case

As result of injection process, observes the injection effect on well bottom hole pressure in HE-28 as increasing from 242.414psia at 1\1\2014 (break through time) to 280.776psia at 1/12/2020 as show in below fig

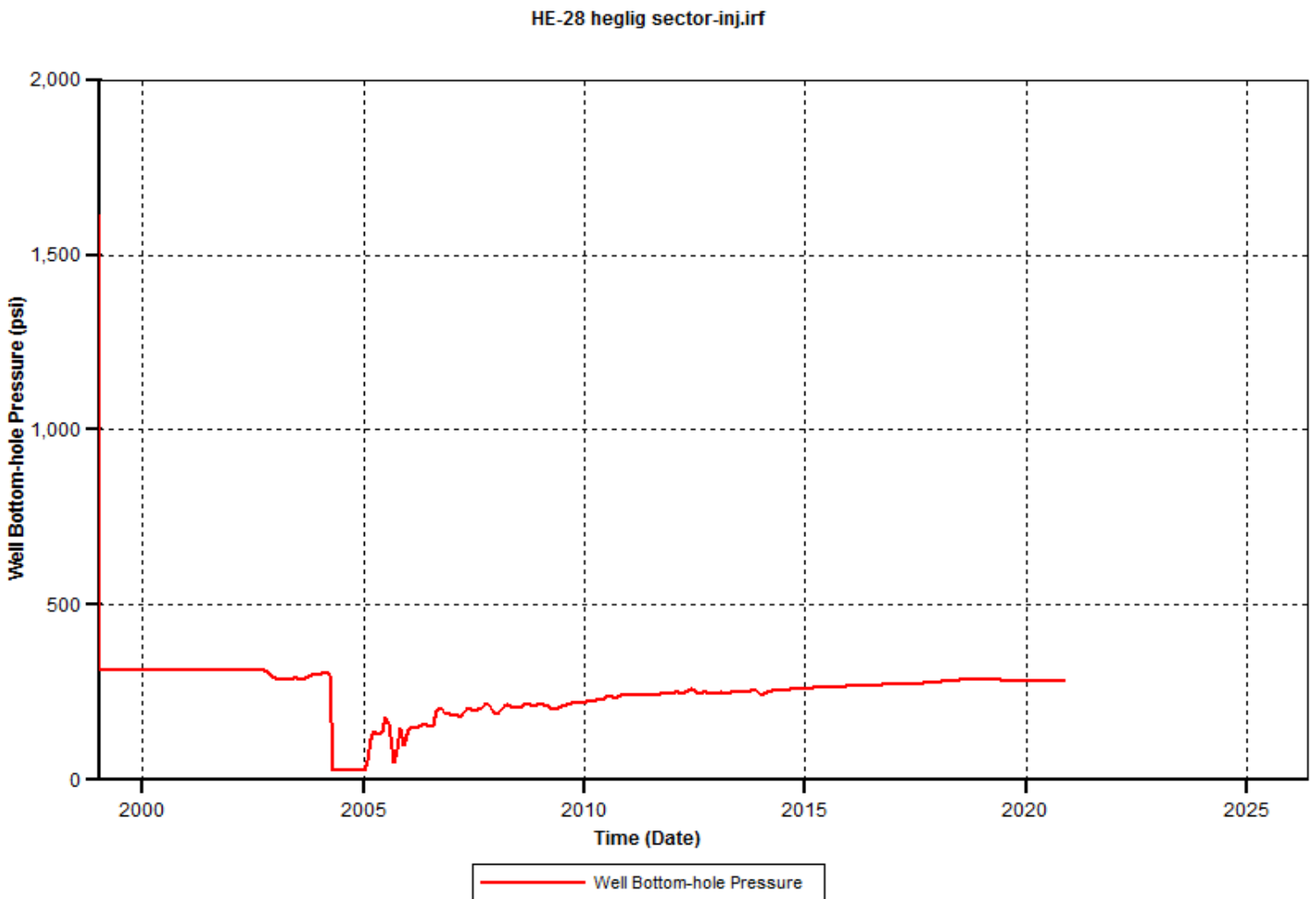


Fig 4 - 8 well bottom hole pressure in HE-28 after injection case

As result for injection process , observes of injection affect on water rate in HE-28 as increasing from 1094.53bbl/day at 1\1\2014 (break through time) to 1535.57bbl/day at 1/12/2020 as show in below fig

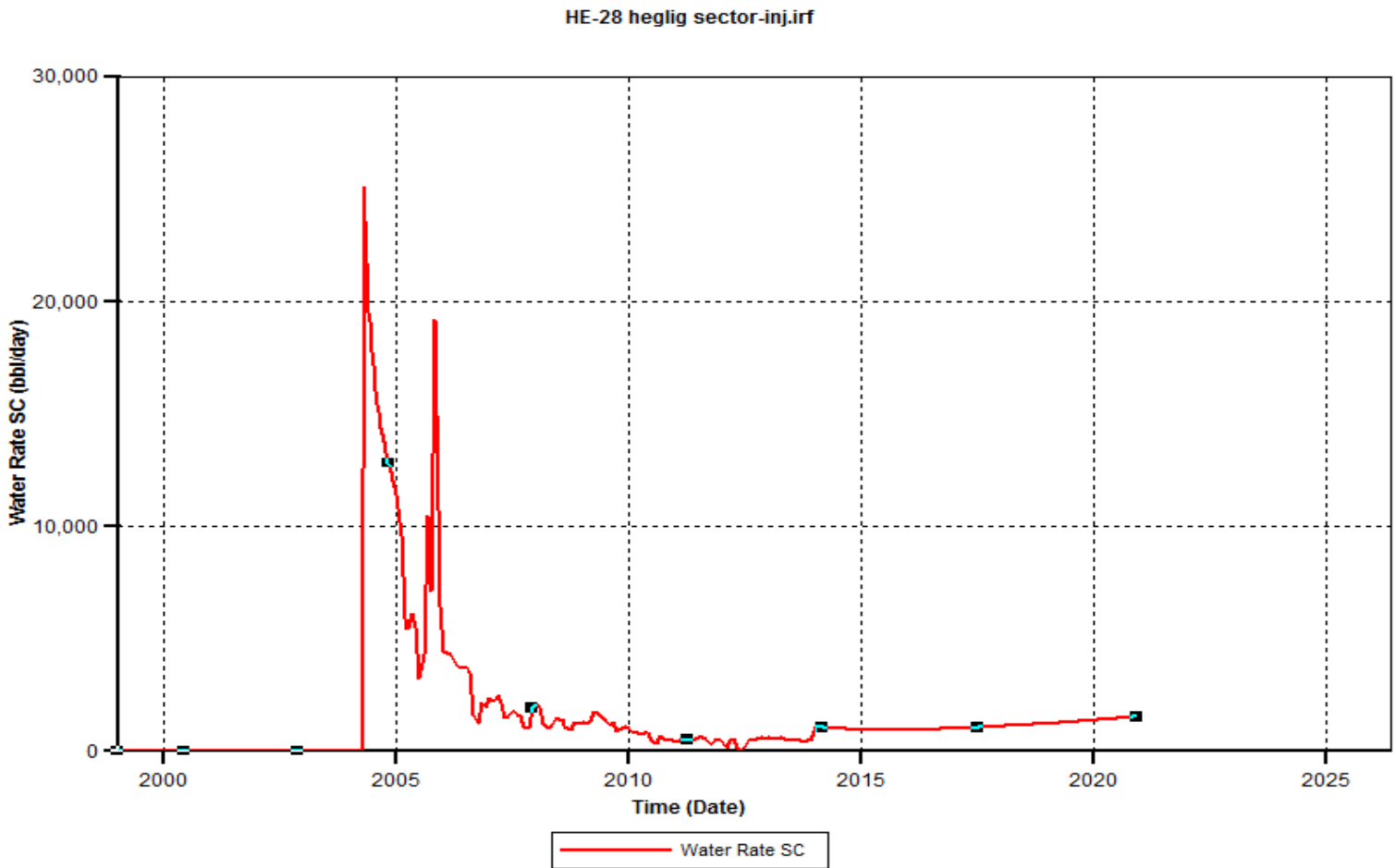


Fig 4 - 9 water rate in HE-28 after injection case

4.4 Final Results

The optimization of the injection and production parameters lead to obtain an increment of 0.78137 MMbbl in the cumulative oil production, and a decrement of 26.524 MMbbl in the cumulative water production, compared to the base case.

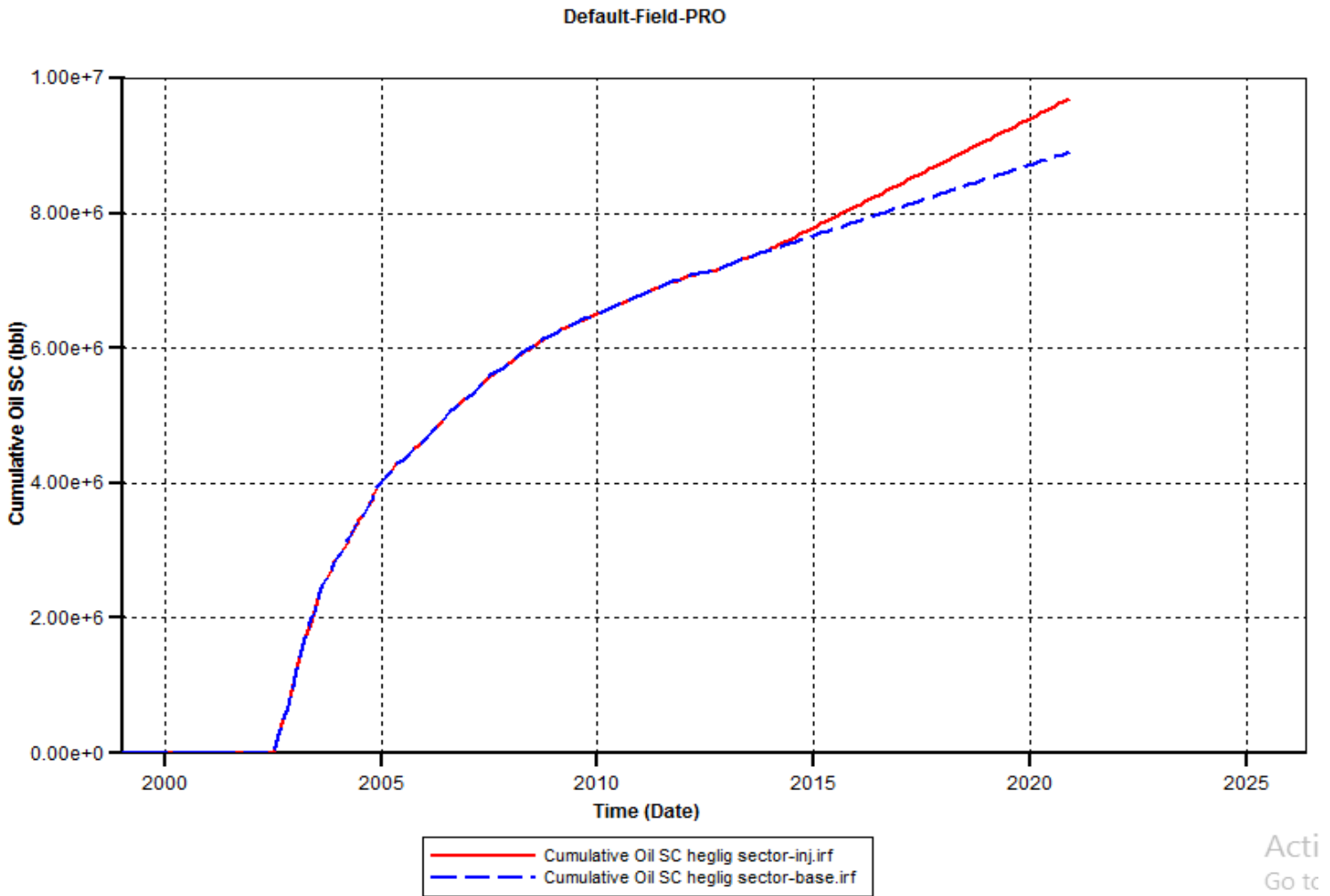


Fig 4 - 10 Comparison between the cumulative production of the base case and the injection case for entire field.

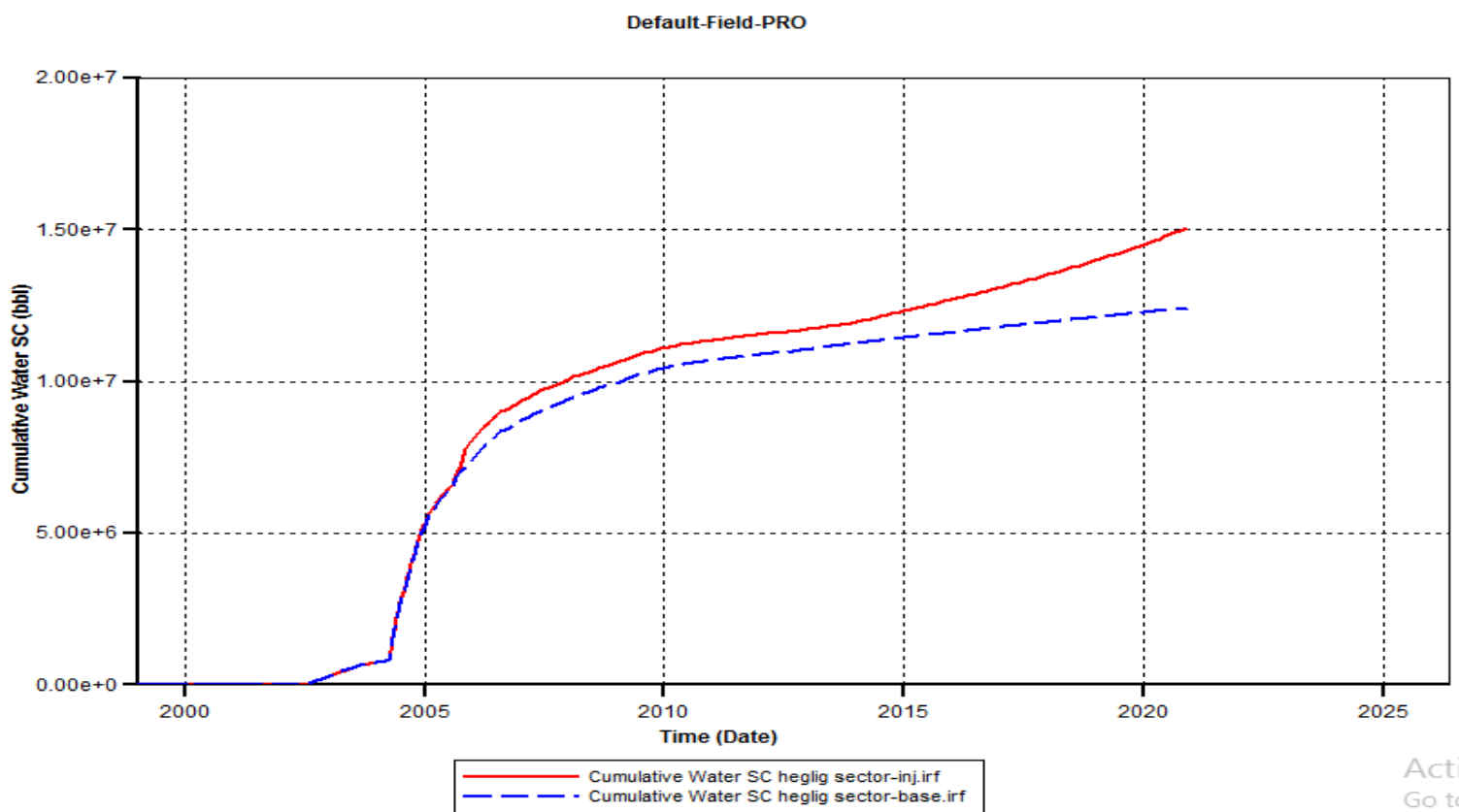


Fig 4 - 11 Comparison between the cumulative water production of the base case and the injection case.

Chapter 5

Conclusions and Recommendations

5.1 Conclusions

This study used combination of geological, and reservoir data with production data to make a comparison process between two cases (before and after injection case). this study implemented by using CMG software in Heglig main oil field, depending on obtaining result the following conclusion can be given.

- The possibility of increasing the recovery factor for Heglig main oilfield has been studied.
- The increasing of recovery factor emerged clearly through comparison process.
- Designing of a well pair ASP Flooding model for Heglig main oil field using CMG software has been implemented.
- A comparison process between two cases has been done and showed in results graph.
- Pilot results has been set as comparison results in order to further refine to the chemical EOR full-field model.

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 perform a detailed economical evaluation of the flooding processes. That includes economical concentrations of alkaline, surfactant, and polymer.

References

- 1- ALI, H. A., MUSA, T. A. & DOROUDI, A. Chemical Enhanced Oil Recovery Pilot Design for Heglig Main Field-Sudan. SPE Saudi Arabia Section Annual Technical Symposium and Exhibition, 2015. Society of Petroleum Engineers.
- 2- SHUTANG, G., HUABIN, L., ZHENYU, Y., PITTS, M., SURKALO, H. & WYATT, K. 1996. Alkaline/surfactant/polymer pilot performance of the West Central Saertu, Daqing oil field. SPE Reservoir Engineering, 11, 181-188.
- 3- DELSHAD, M., HAN, W., POPE, G., SEPEHRNOORI, K., WU, W., YANG, R. & ZHAO, L. Alkaline/surfactant/polymer flood predictions for the Karamay oil field. SPE/DOE Improved Oil Recovery Symposium, 1998. Society of Petroleum Engineers.
- 4- BARREAU, P., LASSEUX, D., BERTIN, H., GLENAT, P. & ZAITOUN, A. Polymer adsorption effect on relative permeability and capillary pressure: investigation of a pore scale scenario. International Symposium on Oilfield Chemistry, 1997. Society of Petroleum Engineers.
- 5- VARGO, J., TURNER, J., VERGNANI, B., PITTS, M. J., WYATT, K., SURKALO, H. & PATTERSON, D. Alkaline-surfactant-polymer flooding of the Cambridge Minnelusa field. SPE Rocky Mountain Regional Meeting, 1999. Society of Petroleum Engineers.
- 6- HUNKY, R. M., WU, Y., BAI, B. & DUNN-NORMAN, S. An experimental study of alkaline surfactant flooding for ultra-shallow heavy oil reservoirs. SPE Western Regional Meeting, 2010. Society of Petroleum Engineers.
- 7- IBRAHIM, Z. B., MANAP, A. A. A., HAMID, P. A., HON, V. Y., LIM, P. H. & WYATT, K. Laboratory aspect of chemical EOR processes evaluation for Malaysian oilfields. SPE Asia Pacific Oil & Gas Conference and Exhibition, 2006. Society of Petroleum Engineers.
- 8- FAROG, A., A MUSTAFA, H., MUKHTAR, E., ELBLAOULA, H., A YASSIN, B., TAGWA, M., MUCHARAM, L. & ABDALLA, F. Implementation of Chemical EOR as Huff and Puff to Improve Oil Recovery for Heavy Oil Field by Chemical Treatment SEMAR Cast Study Bamboo Oil Field. SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, 2016. Society of Petroleum Engineers.
- 9- ROMERO-ZERÓN, L. 2016. Chemical Enhanced Oil Recovery (cEOR): A Practical Overview, InTech.
- 10- Reservoir Management Fundamentals [Online]. Available: <http://www.oil-gasportal.com/reservoir-management/fundamentals/> [Accessed 18 October 2018.]

OSE, A. T. 2011. Oil Recovery Processes [Online]. Available: <https://www.scribd.com/document/65129121/Oil-Recovery-Processes> [Accessed 18 October 2018].

11- Hydrophobic Polymers Flooding - Scientific Figure on ResearchGate. [Online]. Available: https://www.researchgate.net/Polymer-flooding_mechanism_fig3_318245134 [accessed 20 Oct, 2018].