NEAR EAST UNIVERSITY
INSTITUTE OF GRADUATE STUDIES
DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

NUMERICAL INVESTIGATION OF POLYMER FLOODING IN GHAWAR FIELD, SAUDI ARABIA

MSc. THESIS

Anthony Olise BIOSE

Nicosia
June, 2022

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Supervisor

Prof. Dr. Cavit ATALAR

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Approval

We certify that we have read the thesis submitted by Anthony Olise BIOSE titled **"Numerical Investigation of Polymer Flooding in Ghawar Field, Saudi Arabia"** and that in our combined opinion it is fully adequate, in scope and in quality, as a thesis for the degree of Master of Applied Sciences.

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Declaration

I hereby declare that all information, documents, analysis and results in this thesis have been collected and presented according to the academic rules and ethical guidelines of Institute of Graduate Studies, Near East University. I also declare that as required by these rules and conduct, I have fully cited and referenced information and data that are not original to this study.

Anthony Olise BIOSE

29/06/2022

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Anthony Olise BIOSE

Abstract

Numerical Investigation of Polymer Flooding in Ghawar Field, Saudi Arabia

BIOSE, Anthony Olise

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Polymer flooding has been used for more than 40years to effectively recover the remaining oil from the reservoir. In this research, polymer was used to increase the water viscosity in the Ghawar oil field for better sweep efficiency and favorable mobility ratio, which resulted in a better recovery factor than waterflooding. A significant amount of oil in the reservoir was unrecoverable when the primary recovery (natural drive) and secondary recovery (water flooding) method was applied. In using the tertiary stage (EOR) to get a better recovery factor, it was proven that this recovery stage is the best method to use in getting better sweep efficiency and favorable mobility ratio. This tertiary stage process is also known as enhanced oil recovery which uses polymer, surfactant, and alkali in increasing the recovery factor and cumulative oil.

CMG was the simulator used to model the reservoir and history match with the actual production data. The most crucial factor considered when increasing oil production is; polymer injection duration and polymer molarity. Injecting water into higher oil viscosity leads to an unfavourable mobility ratio and on the other hand, injecting polymer solution will result in a more favorable mobility ratio, which also provides sweep efficiency improvement and a better oil recovery method. Different scenarios of 0.15, 1.5, 3.0 and 4.5M were used just to attain a better recovery factor, it was observed the more the polymer molarity is increased the recovery factor also increases.

The result from the analysis indicates that the recovery factor of primary recovery (natural drive) is 11%, secondary recovery (waterflooding) is 45%, and enhanced oil recovery (polymer Injection) recovered maximum of 60% after the simulation analysis. The simulation analysis was for a duration of 3652days, the cumulative oil for waterflooding is 8.44819e+006(bbl) in 3652days, while the cumulative oil in polymer injection is 1.12445e+007(bbl) in 3652days. Single injector well and production well was strategically drilled into the field, and there was polymer injection for a better recovery factor and cumulative oil recovery.

***Keywords*:** Enhanced oil recovery, computer modeling group, polymer flooding, Ghawar oil field, water flooding.

Özet

Suudi Arabistan, Ghawar Alanında Polimer Taşmasının Sayısal İncelenmesi

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MSc. Petrol ve Doğal Gaz Mühendisliği Bölümü

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Rezervuardan kalan petrolü etkin bir şekilde geri kazanmak için 40 yılı aşkın bir süredir polimer taşması kullanılmaktadır. Bu araştırmada, daha iyi süpürme verimliliği ve uygun hareketlilik oranı için Ghawar petrol sahasındaki su viskozitesini arttırmak için polimer kullanıldı, bu da su basmasından daha iyi bir geri kazanım faktörü ile sonuçlandı. Birincil geri kazanım (doğal tahrik) ve ikincil geri kazanım (su basması) yöntemi uygulandığında rezervuardaki önemli miktarda petrol kurtarılamazdı. Daha iyi bir kurtarma faktörü elde etmek için üçüncül aşamayı (EOR) kullanırken, bu kurtarma aşamasının daha iyi süpürme verimliliği ve uygun hareketlilik oranı elde etmede kullanılacak en iyi yöntem olduğu kanıtlanmıştır. Bu üçüncü aşama prosesi aynı zamanda polimer, yüzey aktif madde ve alkaliyi geri kazanım faktörünü ve kümülatif yağı arttırmada kullanan gelişmiş yağ geri kazanımı olarak da bilinir.

CMG, rezervuarı modellemek için kullanılan simülatördü ve gerçek üretim verileriyle geçmiş eşleşmesini yaptı. Petrol üretimi artırılırken göz önünde bulundurulan en önemli faktör; polimer enjeksiyon süresi ve polimer molaritesi. Daha yüksek petrol viskozitesine su enjekte etmek, olumsuz bir hareketlilik oranına yol açar ve diğer yandan, polimer çözeltisinin enjekte edilmesi, aynı zamanda süpürme verimliliği iyileştirmesi ve daha iyi bir petrol geri kazanım yöntemi sağlayan daha uygun bir hareketlilik oranı ile sonuçlanacaktır. Sadece daha iyi bir geri kazanım faktörü elde etmek için 0.15, 1.5, 3.0 ve 4.5M'lik farklı senaryolar kullanıldı, polimer molaritesi arttıkça geri kazanım faktörünün de arttığı gözlemlendi.

Analizden elde edilen sonuç, simülasyon analizinden sonra birincil geri kazanımın (doğal tahrik) geri kazanım faktörünün %11, ikincil geri kazanımın (su basması) %45 olduğunu ve geliştirilmiş yağ geri kazanımının (polimer Enjeksiyonu) maksimum %60 oranında geri kazanıldığını göstermektedir. Simülasyon analizi 3652 günlük bir süre içindi, su basması için kümülatif yağ 3652 günde 8.44819e+006(varil) iken, polimer enjeksiyonunda kümülatif yağ 3652 günde 1.12445e+007(varil) idi. Tek enjektörlü kuyu ve üretim kuyusu stratejik olarak sahada açıldı ve daha iyi bir geri kazanım faktörü ve kümülatif petrol geri kazanımı için polimer enjeksiyonu yapıldı.

Anahtar Kelimeler: Gelişmiş petrol geri kazanımı, bilgisayar modelleme grubu, polimer taşması, Ghawar petrol sahası, su taşması.

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List of Abbreviations

ASP:	Alkaline Surfactant Polymer
Bbl/day:	Billion Barrel Per Day
Cp:	Polymer Concentration
CMG:	Computer Modelling Group
Ea:	Areal Sweep Efficiency
Ev:	Volumetric Sweep Efficiency
EOR:	Enhanced Oil Recovery
EUR:	Estimated Ultimate Recovery
HPAM:	Hydrolyzed Polyacrylamide
IFT:	Inter-Facial Tension
IPV:	Inaccessible Pore Volume
k:	Formation Permeability
kro:	Oil Relative Permeability
krw:	Water Relative Permeability
LSP:	Low Salinity Polymer
M:	Molarity
MPI:	Message-Passing Interface
Nc:	Capillary Number
OOIP:	Original Oil in Place
φ:	Porosity
%:	Percentage
Pcow:	Oil Water Capillary Pressure
Pcgo:	Gas Oil Capillary Pressure
PF:	Polymer Flooding
ρ:	Phase Density
PV:	Pore Volume
R:	Residual Phase
RF:	Recovery Factor
Soi:	Initial Oil Saturation

So:	Oil Saturation
Swi:	Irreducible Water Saturation
Sorw:	Waterflooding Residual Oil Saturation
Sw:	Water Saturation
SP:	Surfactant Polymer
Winj:	Water Injection
WF:	Waterflooding
WTI:	West Texas Intermediate
XA:	Xanthan

CHAPTER 1
Introduction

About 15% of original oil in place (OOIP) is recovered from the reservoir well by the natural drive energy (primary recovery) method and another 15% by secondary recovery method. The remaining 70% are unrecovered because of the pressure of the reservoir of which natural drive energy and water cannot recover a significant amount of oil, chemical such as polymer was used for better recovery factor and these recovery stages are shown in Figure 1.1 below (Mansour et al., 2019).

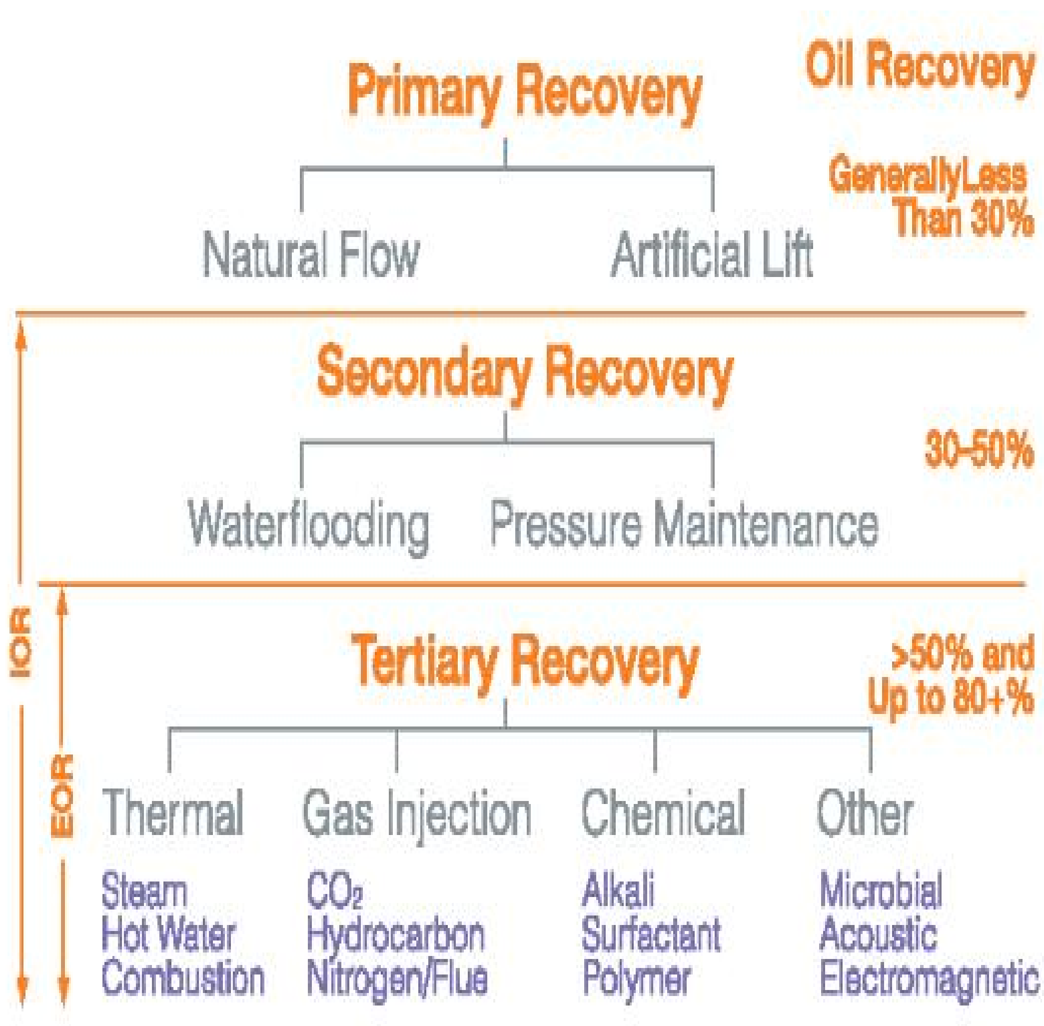

Figure 1.1. *The Recovery Stages in Oil and Gas (Vishnyakov and Zeynalov, 2020)*

Primary Recovery (Natural Drive Energy)

The recovery of oil by any of the natural drive mechanisms is called "primary recovery." The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the well bore. There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

- Rock and liquid expansion drive.
- Depletion drive.
- Gas cap drive.
- Water drive.
- Gravity drainage drive.
- Combination drive.

Rock and liquid expansion drive. When an oil reservoir initially exists at a pressure higher than its bubble point pressure, the reservoir is called an "under saturated oil reservoir." At pressures above the bubble point pressure, crude oil, connate water, and rock are the only materials present. As the reservoir pressure declines, the rock and fluids expand due to their individual Compressibility. The reservoir rock Compressibility is the result of two factors:

(1) expansion of the individual rock grains.

(2) formation compaction. This driving mechanism is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil in place.

Depletion drive. This driving form may also be referred to by the following various terms:

- solution gas drive

● dissolved gas drive

● internal gas drive. In this type of reservoir, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space as shown conceptually in Figure below

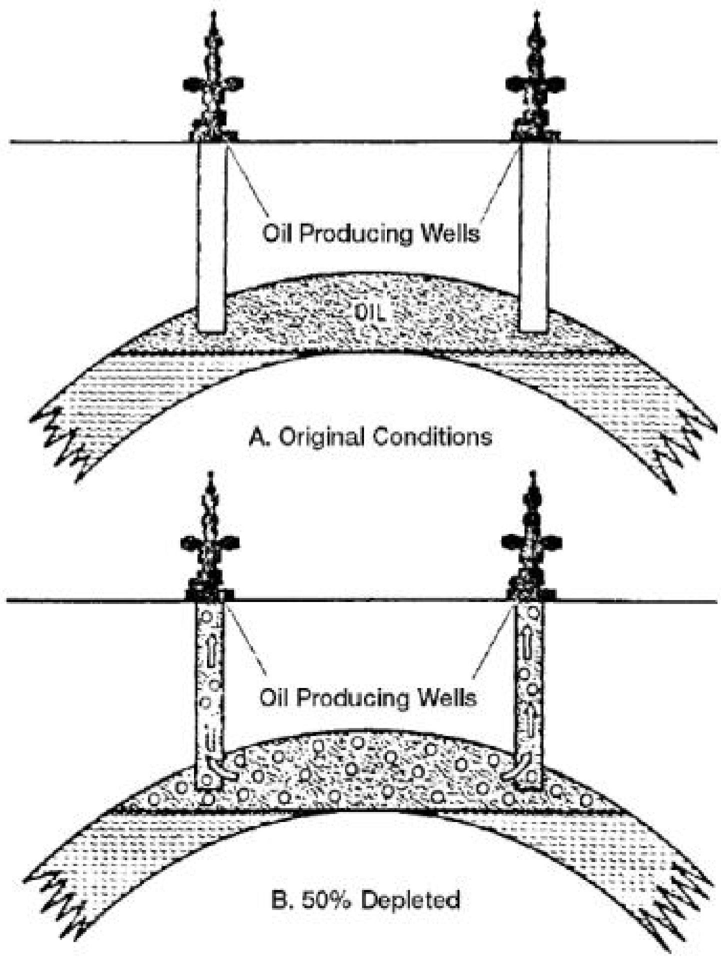

Figure 1.2. *Depletion Drive (Tumba et al., 2019)*

Oil production by depletion drive is usually the least efficient recovery method. Ultimate oil recovery from depletion drive reservoirs may vary from less than 5% to about 30%. The low recovery from this type of reservoir suggests that large quantities of oil remain in the reservoir and, therefore, depletion drive reservoirs are considered the best candidates for secondary recovery applications.

Gas cap drive. Gas cap drive reservoirs can be identified by the presence of a gas cap with little or no water drive as shown in the figure.

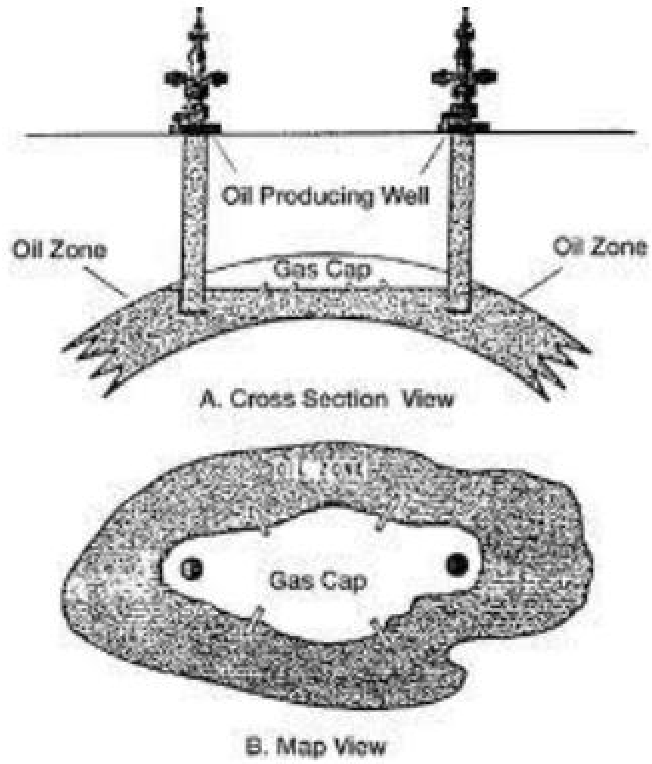

Figure 1.3. *Gas Cap Drive (Sharifipour et al., 2017)*

Water drive. Many reservoirs are bounded on a portion or all of their peripheries by water bearing rocks called aquifers. The aquifers may be so large compared to 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 effects on the reservoir performance.

Gravity drainage drive. The mechanism of gravity drainage occurs in petroleum reservoirs as a result of differences in densities of the reservoir fluids. The fluids in petroleum reservoirs have all been subjected to the forces of gravity, as evidenced by the 7 relative positions of the fluids, i.e., gas on top, oil underlying the gas, and water underlying oil. Due to the long periods of time involved in the petroleum accumulation and migration process, it is generally assumed that the reservoir fluids are in equilibrium. If the reservoir fluids are in equilibrium

Combination drive mechanism. The driving mechanism most commonly encountered is one in which both water and free gas are available in some degree to displace the oil toward the producing wells. The most common type of drive encountered, therefore, is a combination drive mechanism. Two combinations of driving forces are usually present in combination drive reservoirs: (1) depletion drive and a weak water drive, or 9 (2) depletion drive with a small gas cap and a weak water drive. In addition, gravity segregation can also play an important role in any of these two drives. These types of reservoirs usually experience a relatively rapid pressure decline. Water encroachment and/or external gas cap expansion are insufficient to maintain reservoir pressures.

This is the number one way of recovering hydrocarbon in reservoir formation. Primary recovery methods are those that need gas drive solution and aquifer influx that uses natural energy in improving oil production in reservoir formation, which has been the first stage of recovery before introducing waterflooding and enhanced oil recovery (EOR) method. Both using waterflooding and polymer injection is costly compared to primary recovery.

Secondary Recovery (Waterflooding)

The second stage of hydrocarbon production during which an external field such as water or gas is injected into the reservoir through injection well located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbon towards the well-bore. The most common secondary recovery are gas injection and water-flooding. Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. A pressure maintenance can begin during the primary recovery stage but, it is a form or enhanced recovery. The secondary recovery stages reaches its limit when the injected fluid (water or gas) is produce in considerable amounts from the production well and the production is no longer economical. The successive use of primary recover and secondary recover in an oil reserve produce about 15% to 40% of the original oil in place.

Enhanced Oil Recovery (Polymer Flooding)

Enhanced oil recovery by polymer injection is applied after the waterflooding process in the recovery stages to increase the water viscosity for a favorable mobility ratio and a better sweep efficiency. Water-miscible HPAM is added to water to increase the oil as an end product, which is better than the secondary recovery (water flooding), but increasing production due to polymer flooding may be small when reducing the quantity of polymer injection. This research practically shows that optimizing polymer injection is a crucial factor in enhanced oil recovery. The process of chemical (EOR) analysis in the field with Computer Modeling Group 2015, was performed in this research thesis. The discussion was made based on the rheology attribute in the reservoir formation. An increase in oil recovery with polymer injection can be achieved due to polymer molecular weight and molarity of the polymer. Reservoir engineers confirm pressure injectivity is formed closed to the well-bore part and can be classified as the behavior of shear thickening of the polymer which limits the injection. The increase in oil recovery is noticeable when high polymer molecular weight is injected than when high molarity of the polymer is used. Moreover, the injection yields poor polymer elastic properties when pre-shearing the polymer solution but retains a good viscous attribute. Note that a good injection of the polymer in the presence of oil is a two-phase flow and when oil is absent it is one phase flow. The research explains more enhanced oil recovery with the important factors when increasing oil recovery. Oil production shows the importance of polymer flooding. HPAM viscoelasticity plays a crucial part in improving sweep efficiency over water flooding in general and pseudo-plastic fluid in particular, especially at adverse mobility ratios and when reservoir heterogeneity is high (Sheng et al., 2018).

Moreover, for more current reviews concerning oil improvement in oil production, the polymer should be injected in high quantity, though, injection at high quantity may not be achieved due to mechanical degradation that reduces injection. When oil is trapped in the porous medium of the reservoir, It was discovered that about 70% of the original oil in place remains unrecovered after the primary and waterflooding and the trapped oil may be caused due to reservoir heterogeneity, though some other factors can still cause it. Tertiary recovery using polymer injection is one of the best EOR techniques when recovering oil in the reservoir, especially because of the affordability price. The essence of using polymer flooding is to increase the viscosity of the water, which will provide a more favorable mobility ratio in the reservoir. The three known tertiary recovery stages are polymer, surfactant, and alkaline, but polymer was used to increase the recovery factor in this research work. Petroleum engineers discovered when there is high temperature, high salinity, and reservoir brine can cause low viscosity. Tertiary recovery is better than waterflooding both in the field and laboratory according to the thesis. Many reservoir simulators like CMG, ECLIPSE, and UTCHEM can be used to run the analysis, but, Computer Modeling Group 2015, CMG (GEM), is the simulator used to run this thesis analysis.

Thesis Problem Statement

In 2019, the Ghawar oil field was able to produce significant oil using waterflooding, but, will need to be improved in the subsequent production. Reservoir engineers discovered that oil recovery is in three stages, primary, secondary and tertiary stages (Tumba et al., 2019).

The first stage use natural drive energy and the second stage use water or gas to recover oil in the reservoir, but approximately 70% of original oil in place is still trapped in the reservoir and that is why the third stage uses polymer, surfactant, and alkali to recover more oil in the reservoir (Gbadamosi et al., 2020).

Note that primary recovery was able to recover about 15%, an additional 15% was recovered using secondary recovery, while approximately 70% are unrecovered due to oil trapped in the reservoir.

Purpose of the Study

The main aim of this research was to optimize the production of oil from the Ghawar oil field with CMG, using polymer injection. In the process, it shows the ability of the viscoelasticity properties of the HPAM to enhance the sweep efficiency, compared to the water-flooding and primary recovery. Secondly, compare the recovery factor and cumulative oil result of different polymer molarity, water-flooding, and primary recovery. The purpose of any tertiary recovery process is to achieve higher ultimate oil recovery when altering the fluid-fluid or fluid-rock properties.

Factors Use to Calculate the Amount of Oil Recovery of the Reservoir

Pore-scale displacement is a measure of how much of the oil is pushed out from any of the rocks accessed by the injected fluid. Sweep calculate how much reservoir rock is been reached by injected fluid. Drainage is the extend by means well will be able to have entrance in the separate segment based on the well. The commercial cut-of which is the last phase indicates the limit economics production and figure 1.2 below shown below is the factors used in calculating % oil recovery

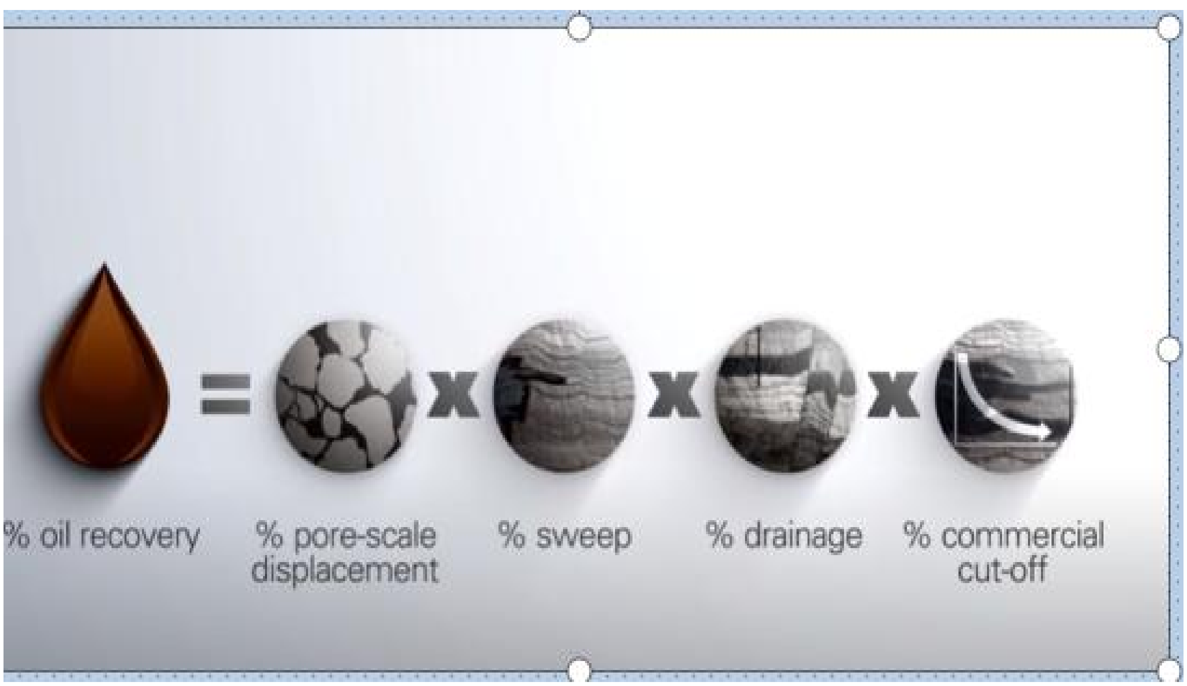

Figure 1.4. *Four Factor Use in Calculating % Oil Recovery (Karatayev and Clarke, 2016)*

Mechanism of Polymer

Injecting water into higher oil viscosity leads to an unfavorable mobility ratio, and on the other hand, injecting polymer solution will result in a more favorable mobility ratio, which also provides sweep efficiency improvement and a better oil recovery method as shown in figure 1.3 below. The polymer viscoelasticity characteristics depend on polymer molecular weight, molarity, and petrophysical properties of the reservoir like permeability and porosity (Lotfollahi et al., 2019).

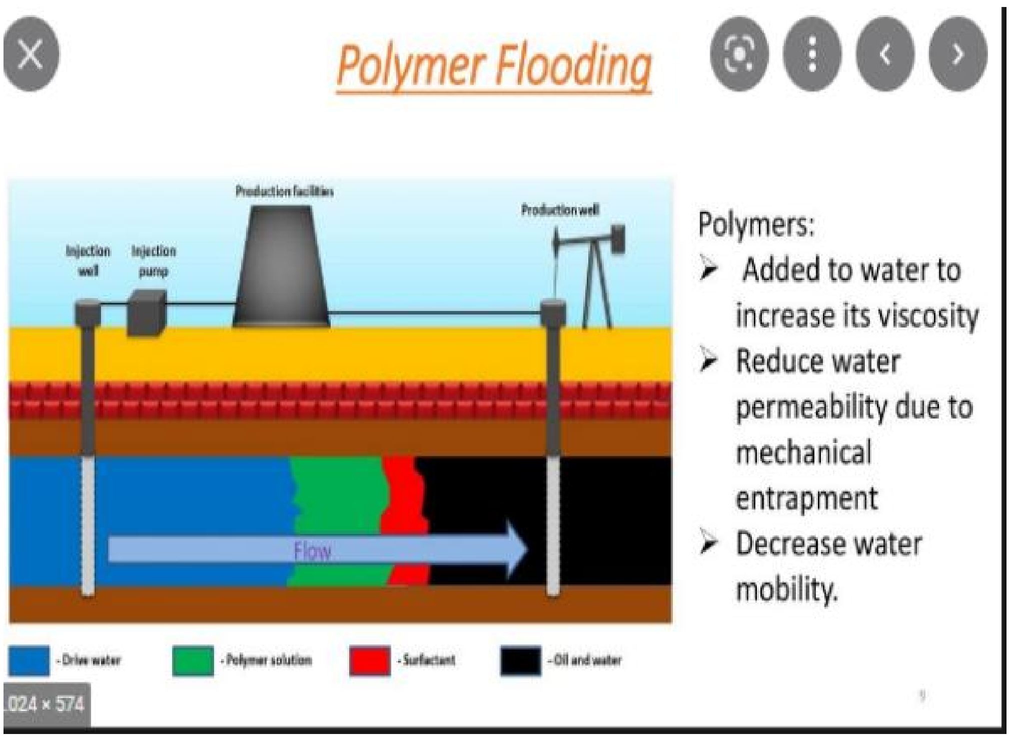

Figure 1.5. *Mechanism of Polymer Flooding (Qi et al., 2017)*

Research Question/Hypothesis

Does spending money to buy polymer in enhanced oil recovery for a better recovery factor worth it when there is a water flooding method?.

Off course, spending money on the polymer is worth it because in this thesis the maximum recovery factor of polymer injection is 60% while waterflooding recovery factor is 45%, the cumulative oil for waterflooding is 8.44819e+006(bbl) in 3652days, while the cumulative oil in polymer injection is 1.12445e+007(bbl) in 3652days, as you can see the difference is very clear.

Significance of the Study

About 70% of oil is unrecovered after the first stage of recovery and the second stage of recovery, then tertiary recovery method using polymer injection is applied to have a better sweep efficiency and favorable mobility ratio due to the polymer that increases the viscosity of the water for more oil recovery in the reservoir formation.

Limitation of Study

Since 1951 the production of oil in the Ghawar oil field started, reservoir properties and production data have been developed but, not intensively enough literature review/research. In this effect, it simply means more information on the variable that is yet to be published for easy access in society are estimated realistically for a better result.

Simulation Concept

Technology has allowed engineers to review a model of the reservoir divided to several gird cells, giving them elasticity like never before. It opened the possibilities of predicting reservoir performances quickly. Within the simulation, it is possible to simulate the same reservoir given different values of variables as a sensitivity assessment or how the reservoir will react to various fluid properties using high-speed processors. The data gathered for the simulations must be carefully recorded otherwise incorrect data will influence the outcome leading to poor, unreliable results. Therefore, reservoir simulation can answer crucial questions such as how much hydrocarbons are present, how much of it can be recovered, how fast it can be recovered, and the best method of recovery.

Limitation of Simulation

A simulation provides a yes or no to different scenarios but, does not exactly direct an engineer towards creative solutions. Another problem with simulation is that the initial collection of data is very expensive which can bring uncertainty to doing the simulation as it might not be economic, this issue also limits the accuracy of the simulation as it might not be feasible to get more data meaning some estimations will be used. Even as the technology improves reservoir simulation will always inherit uncertainty from various parts of geosciences and reservoir engineering.

CHAPTER II
Literature Review

Production of oil with the recovery of 15% of the original oil in place (OOIP) has the capability of producing it using high polymer molarity because polymer solution with higher molarity as well as high molecular weight improves oil recovery. This happens because viscoelasticity effect which enables reducing residue oil saturation after waterflooding (Qi et al., 2017).

Moreover, Erincik et al. (2017) showed a newly remarkable result of further reducing residue oil saturation of low salinity viscoelasticity polymer by injecting high salinity viscoelasticity polymer, however, they reported that the mechanism behind this observation requires further investigation.

After the initial stage by initial (or natural) reservoir pressure of the trapped oil, and water flooding of the reservoir, residual oil, and bypassed oil are left in the reservoir (Gbadamosi et al., 2020). For marginal oil fields characterize by low oil production at the life of the field, the remaining oil is recovered using tertiary drive mechanisms otherwise referred to as tertiary stage recovery (EOR). "Several tertiary stages (EOR) process is used for recovering crude oil from reservoirs, and the process is grouped into two; non-thermal and thermal. Thermal processes are suitable with unconventional heavy oil, bitumen, and tar sands, unlike non-thermal. The injected chemicals used for EOR include polymers, surfactant, alkali, and foams" (Agi et al., 2020).

Theoretical Framework

Since the inception of the Ghawar oil field in Saudi Arabia in 1951 that the oil production started, observation was made that much oil cannot be recovered, knowing that the waterflooding process that is used will not be able to increase the water viscosity that helps to have a better sweep efficiency and favorable mobility ratio. Abbas et al. (2020) uses a production data to improve on the existing recovery factor and it was discovered that there was a significant improvement when waterflooding was used but improving on the existing recovery factor was a serious concern, later when he used another production data to run the simulation analysis, so many observation was indicated such as the factors that can make him get a better recovery.

In the result, there was an increase in recovery factor when there is an increase in the permeability of the production data. Properties such as reservoir temperature, porosity, depth, rock Compressibility, and reservoir pressure were at the same value in all the analysis that was run, but the factor that drastically improved the recovery factor was the number of well injected because observation showed that the more the production well the better the recovery. Secondly, there was an increase in polymer molarity which is another reason for better recovery in the second analysis. On the feature analysis, increase the number of years because observation showed that the more the duration (simulation time) the more the recovery factor. Making first a pilot is a rule especially when reservoir conditions involve injection conformance issues such as multi-layer heterogeneous fluvial reservoirs of friable/unconsolidated sandstone and viscous/heavy oil. When polymer flooding is applied in a tertiary stage the incremental oil of the process is clear, the mistake could go unnoticed when history matching polymer floods using rheology model and polymer model parameters implemented in commercial simulators.

These models lack intensive testing and debugging because few projects have been implemented and fewer projects have been studied in-depth with comprehensive analysis and multi-scale reservoir simulations model. Pre-shearing is expected to happen at the perforations leading to a progressive moderation of shear thickening rheology. Authors use rheometer curve and shear thinning models, but fail to describe the relationship between the rheometer curves and resistance factor, and whether the water flows velocities are coherent with the effective viscosity used for calculating cell flows. As these problems are not discussed by the authors, they are unaware of the pitfalls of the rheology model.

Steps on this Thesis

- Literature review/ data collection
- Generate polymer model.

● Run reservoir simulations analysis with CMG (GEM) using the reservoir rock and fluid properties.

●Run the analyses with a slug of polymer injection of polymer molarity of 0.15M.

●Run the same analysis with no polymer injection, only waterflooding.

●Run a primary recovery with no injection.

●Run the analysis with an increase of different polymer molarity of 1.5, 3.0, and 4.5M for a better recovery factor.

●Plot a graph of the recovery factor of the different polymer molarity, waterflooding, and primary recovery.

●Plot a graph of the cumulative oil of the different polymer molality, waterflooding, and primary recovery. Comparison Of the result.

Related Research

Many petroleum engineers were able to come up with the same ideology on how polymer flooding works in the reservoir, though in most of the experiments it was channeled to increasing recovery factor. Some worked in the field while some perform their analysis in the laboratory to improve the recovery factor which is the main aim of this research, Recently an experiment was conducted by Abbas et al. (2020) on the effect of pre-injection such as pre-shearing that take place in the near well-bore of the reservoir. How polymer injection works has been discussed in so much literature, the importance of polymer molecular weight, injectivity of polymer molarity, and the way of running the simulation analysis using different simulators like UTCHEM or CMG. But in this thesis Computer Modeling Groups, 2015 is used. Data from the laboratory was used to experiment with the importance of fracturing to differentiate the matrix important for polymer injection. The pressure on the injection starts happening close to the well-bore part, and this is known as shear thickening behavior which reduces the capability of the injection in the solution of the polymer. This method is noticeable and important in injecting more molecular weight polymer unlike injecting more polymer molarity.

Moreover, when the polymer solution is been pre-shearing injection, it maintains the viscosity ability of the polymer but, reduces the elastic behavior of the polymer.

It's observed that in reservoir formation polymer injection is better if oil is in it, which is known as a two-phase flow in the reservoir (porous media) unlike when there is an absence of oil, which is one phase flow in porous media. This research explains the concept of polymer flooding and explains the important factor in increasing oil production. The production data used in my simulation analysis increased the recovery factor and cumulative oil in the field, this is so important in our current society due to the price of the oil, Investigation has shown that hydrolyze polyacrylamide (HPAM) and Xanthan (XA) is widely used as the polymer for increasing water viscosity for a better sweep efficiency and favorable mobility ratio both in the onshore and offshore reservoir formation like sandstone and carbonate, unlike when you use secondary recovery (waterflooding). To accelerate oil production, the polymer should be injected at high rates. However, injection at high rates may not be achieved because of polymer viscoelasticity characteristics like mechanical degradation which limit the injection method.

Sweep Efficiency

One way to improve polymer injection is by means of fractures. In some cases, such high molecular weight polymers that are typically used for EOR application cannot be injected into reservoir matrix without fracturing. One of the main challenges faced by analytical models is determining the accurate rate of the shear in reservoir formation. In these given analytical models explain above in the related research, the important rate of the shear in the reservoir formation is modeled by using the continuum approach based on capillary bundle mode. However, this could be improved by pore-scale network modeling that accounts for both polymer physicochemical characteristics and pore properties. For example, identified the relationship between Darcy velocity and shear rate is more complex in porous media and depends on pore-space morphology. Injection of polymer has more favourable mobility ratio than waterflooding because it provides better sweep efficiency improvement as shown in Figure 2.1.

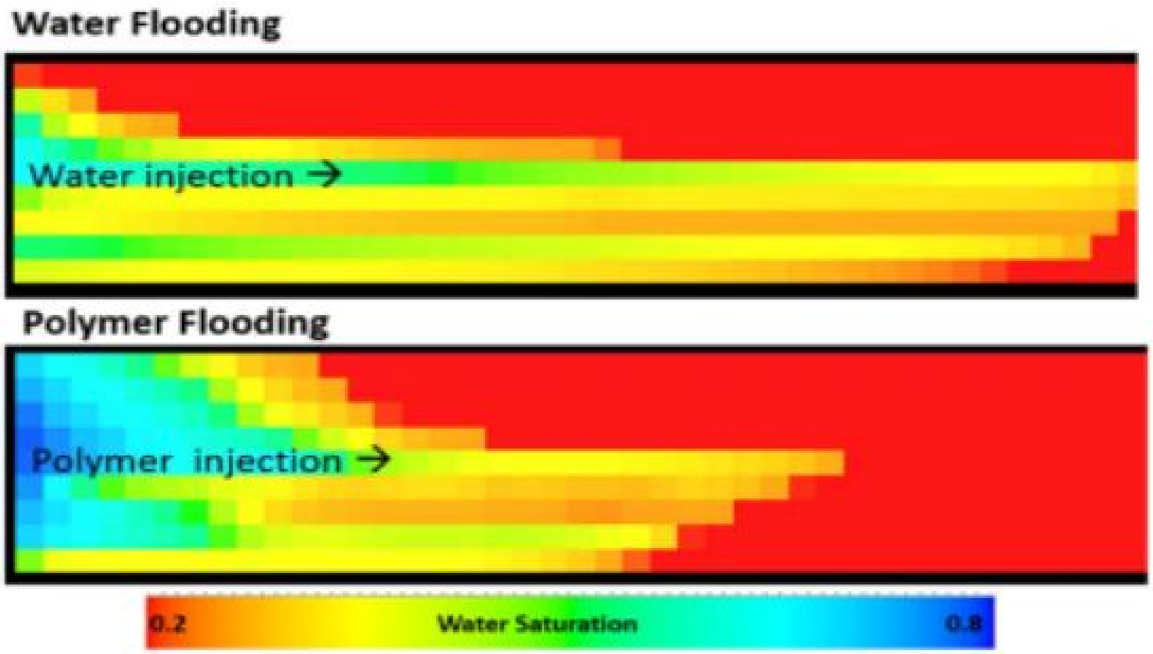

Figure 2.1. *An Illustration of Sweep Improvement with Polymer Injection (Sheng et al., 2018)*

It is important to understand and quantify their impact on polymer injection response before conducting a design optimization. The investigated parameters in this paper are emphasized injection elements and rock-polymer properties. Injecting high polymer molarity is expected to provide better sweep efficiency, but it potentially causes injectivity problems, especially for low permeability rock. Thermal degradation causes injected polymer to lose its original viscosity with time so that the flood front cannot advance far away from its injector. This effects swept oil volume and injector to producer distance design. Rock-polymer properties values can be obtained from lab experiment and they may not be available for all rock type.

Some parts of this thesis explain the EOR technique using polymer to increase the recovery factor and in the process discover the water-oil ratio and gas-oil ratio with Computer Modeling Group 2015. Firstly, its crucial to get the concept of what happened in polymer flooding application, and also understand the factor-like (injection duration of the polymer, molarity of the polymer, and the spacing of the well) to be considered when running such simulation, In the oil production for a better recovery factor using CMG(GEM) and also it is important you differentiate some production data. Injecting high polymer concentration is expected to provide better sweep efficiency, but it potentially causes injectivity problems, especially for low permeability rock. Thermal degradation causes injected polymer losing its original viscosity with time so that the flood front cannot advance far away from its injector. This affects swept oil volume and injector to producer distance design.

Reservoir Simulation

Reservoir simulators simulate behaviors of viscoelasticity in the reservoir using a polymer which helps in optimization and also predicts the result that is likely to get. They are also utilized to evaluate a production plan before applying it to a reservoir. Reservoir simulators have been studied for a long time and many commercial reservoir simulators have been developed and applied in petroleum engineering, such as Computer Modeling Group (CMG) and Schlumberger's simulators. In many cases, when geological models are complicated, such as heterogeneous permeability and porosity, and production processes involve many components, simulations can take a long time. Proper numerical methods, theoretical models and computer hardware have been studied to handle this issue, Despite their recent advances, numerical modeling of large-scale reservoirs remains a challenge, especially modeling tertiary recovery methods. Different people studied single-phase, two-phase, well modeling, black oil model, compositional model, and thermal models, where these models and their solution methods were studied systematically. An engineer who developed a simplified two-dimensional model for thermal reservoir simulations, which could deal with the three-phase flow, a temperature change, energy, and vaporization-condensation effects proposed an implicit numerical scheme, which could be applied to thermal reservoirs models and simplified models, such as isothermal models. A reservoir can have homogeneous porosity and permeability or heterogeneous porosity and permeability.

Waterflooding

Due to the pressure involve in the reservoir well by using enhance oil recovery (chemical method) it has been observed that most oil field only use waterflooding to increase there oil production. This stage of using water to increase oil production is known as secondary recovery, which is capable of improving recovery factor and reducing the cost of production if applied in the reservoir by running the simulation analysis with Computer Modeling Group CMG 2015, that have ability to increase the viscosity of water.

CHAPTER III
Methodology

This research simulation analysis was implemented and obtained favorable results from it. A polymer model of the Ghawar reservoir was created using CMG (GEM) to match the actual reservoir characteristics and performance. After this, the model was run to provide suggestions on how best to produce the remaining oil in place based on the simulation.

Ghawar Oil Field

Approximately 4.8 million barrel of oil per day and 2 billion cubic feet (57,000,000 m^3) of natural gas per day while after 9 years from then 58.32 billion barrels (9.272*10^9 m^3) was their total reserve. In 1965 Ghawar field, Saudi Arabia started using water injection to recover oil. For over 320 years, at the time of Carboniferous Ghawar was in charge of the fold that is not below a basement crack (Bramkamp et al., 1958). The location of the Ghawar field is shown in Figure 3.1.

Figure 3.1. *Location of the Ghawar Oil Field Saudi Arabia (Levorsen et al., 1954)*

Table 3.1.

Reservoir Rock and Fluid Properties in Ghawar Oil Field (Abbas et al., 2020)

	Parameter	Unit	Value
1	Reservoir depth	ft	9010
2	Reservoir pressure	psi	3550
3	Reservoir temperature	F	100
4	Number of grid-blocks, X, Y, and Z	-	21*21*4
5	Permeability	mD	150
6	Porosity	%	0.13
7	API gravity of the oil	degree	18
8	Polymer Molarity	M	0.15,1.5,3.0, and 4.5
9	Injection rate	bbl/day	5000
10	Producer, BHP	psi	500
11	Well Pattern	-	1 Injection and 1 producer
12	Water Viscosity	cp	0.34
13	Oil Viscosity	cp	1.5
14	Rock Compressibility	psi	4.0e-06
15	Simulation time	days	3652

Research Design

CMG (GEM) was used in running the simulation analysis with the sections below:

1) Reservoir data
2) Component
3) Rock fluid

4) Initial condition

5) Numerical data

6) Well and recurrent

In reservoir simulation, the first step is to get reservoir data from a literature review and develop screening studies on polymer, CMG was used as the simulator which maximizes and improves polymer flooding by analyzing the importance of polymer molarity.

The polymer used in this study is partially hydrolyzed polyacrylamide (HPAM). The favorable field conditions of high permeability, low temperature, and low salinity/hardness of formation water rendered this project one of the most successful field-scale applications. Moreover, a successful polymer flooding project was reported, and in the Ghawar oil field in Saudi Arabia (Abbas et al., 2020). The field project has a recovery factor of 54% while in this research recovery factor of 60% was achieved. (Abbas et al. (2020) used a lesser permeability than what this research used and that was the reason a higher recovery factor was obtained. A grid block of 21*21*4 was used which is a total of 1764 grid blocks in the reservoir well as shown in Figure 3.2. below

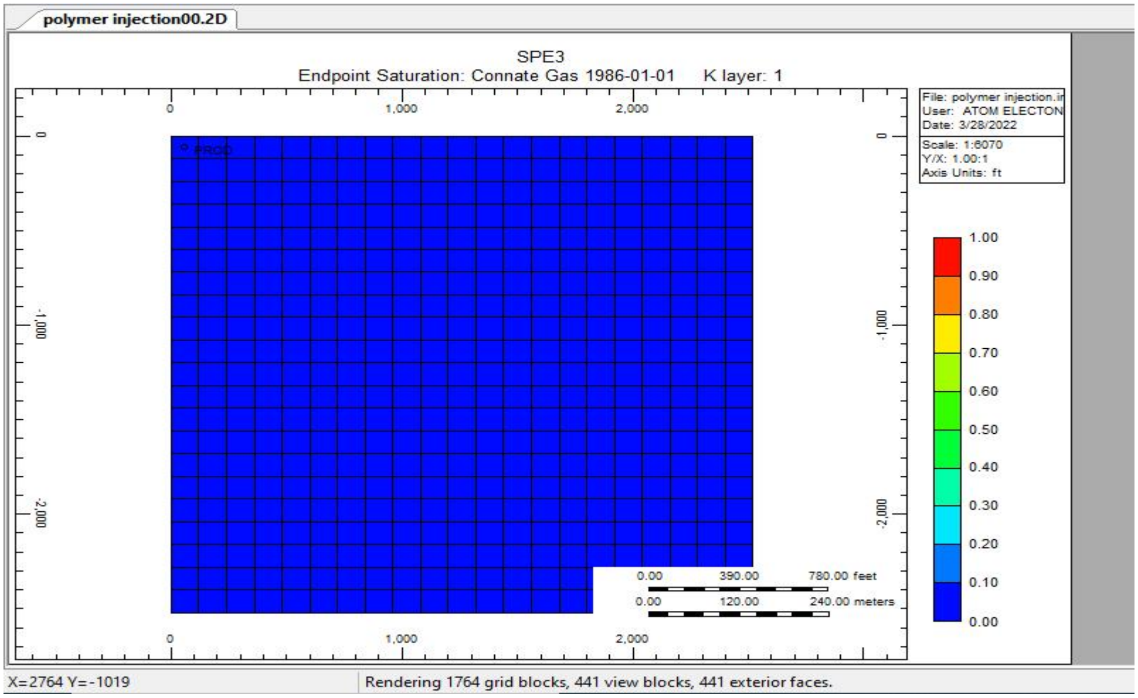

Figure 3.2. *Depth to the Top of the Reservoir Model (Generated from CMG Builder)*

This simulation analysis is a polymer injection in a light oil reservoir with 4 components, one producer, and one injector well. The viscosity of both oil and water at reservoir conditions is 1.5cp and 0.34cp. HPAM with a molarity of 0.15M was injected into the water in the reservoir for it to increase water viscosity, which will favor the mobility ratio and at the same time provide a better sweep efficiency and this injection lasted for a period of 3652days. This process was frequently done in essence to increase the recovery factor and cumulative oil. The reservoir depth was 9010ft, DI is 120, DJ is 120, DK is 50, constant porosity of 0.13, permeability of 150mD, rock compressibility 4.0E-06psi, reservoir temperature 100F, model is polymer, reference pressure 3550psi, Datum depth 9035ft, depth of the water-oil contact (DWOC) is 9950ft. This HPAM molarity of 0.15 was injected for a period of time, but later the polymer molarity was increased to 1.5, 3.0, and 4.0M for a better recovery factor (%) and cumulative oil (bbl/day).

Rock Fluid

Four different graph of relative permeability vs water saturation generated from CMG builder are shown below;

- Graph of Relative Permeability vs Water Saturation
- Graph of Oil Water Capillary Pressure vs Saturated Water
- Graph of Relative Permeability vs Gas Saturation
- Graph of Gas Oil Capillary Pressure vs Gas Saturation

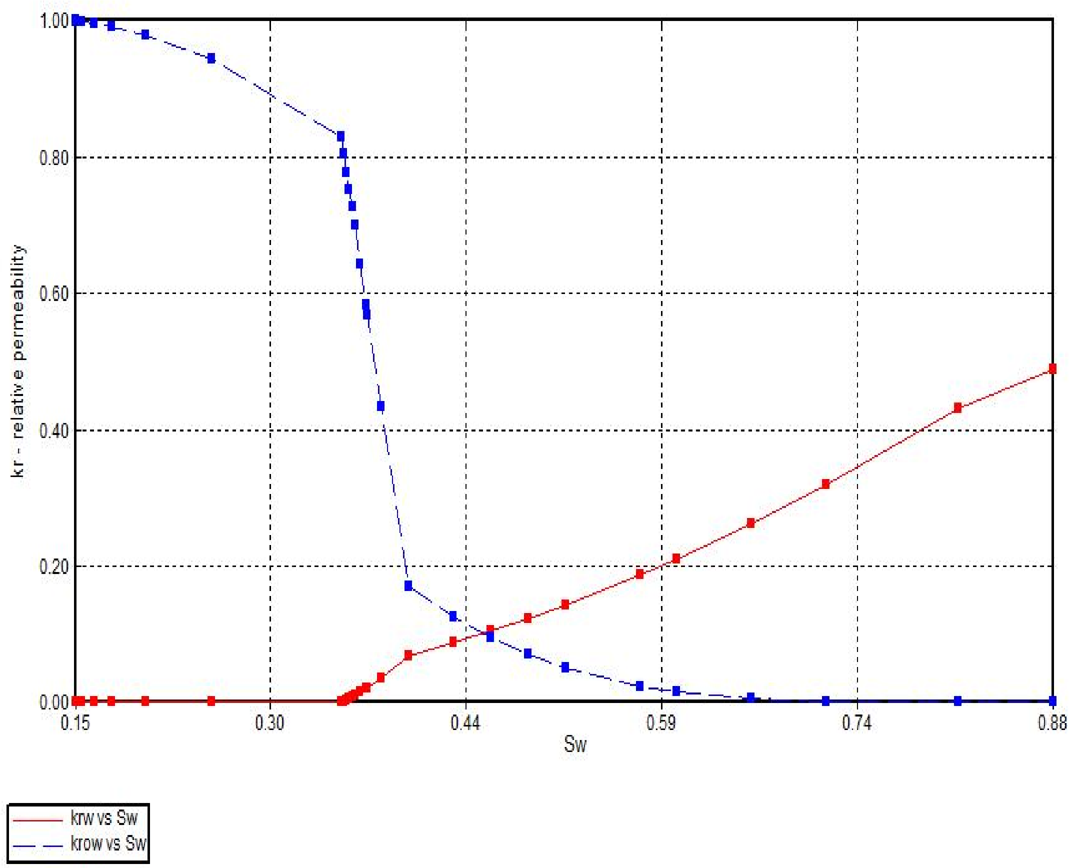

Figure 3.3. *Graph of Relative Permeability vs Water Saturation (Generated from CMG builder)*

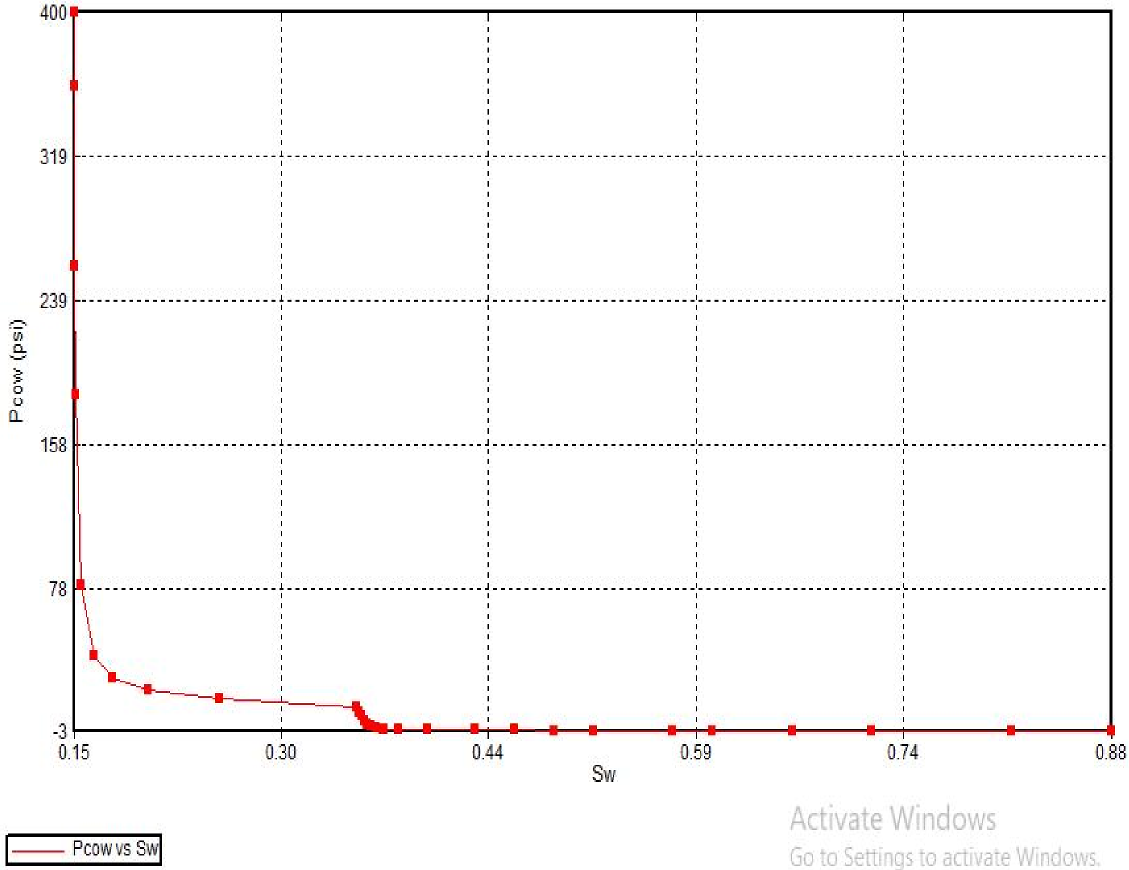

Figure 3.4. *Graph of Oil Water Capillary Pressure vs Saturated Water (Generated from CMG builder)*

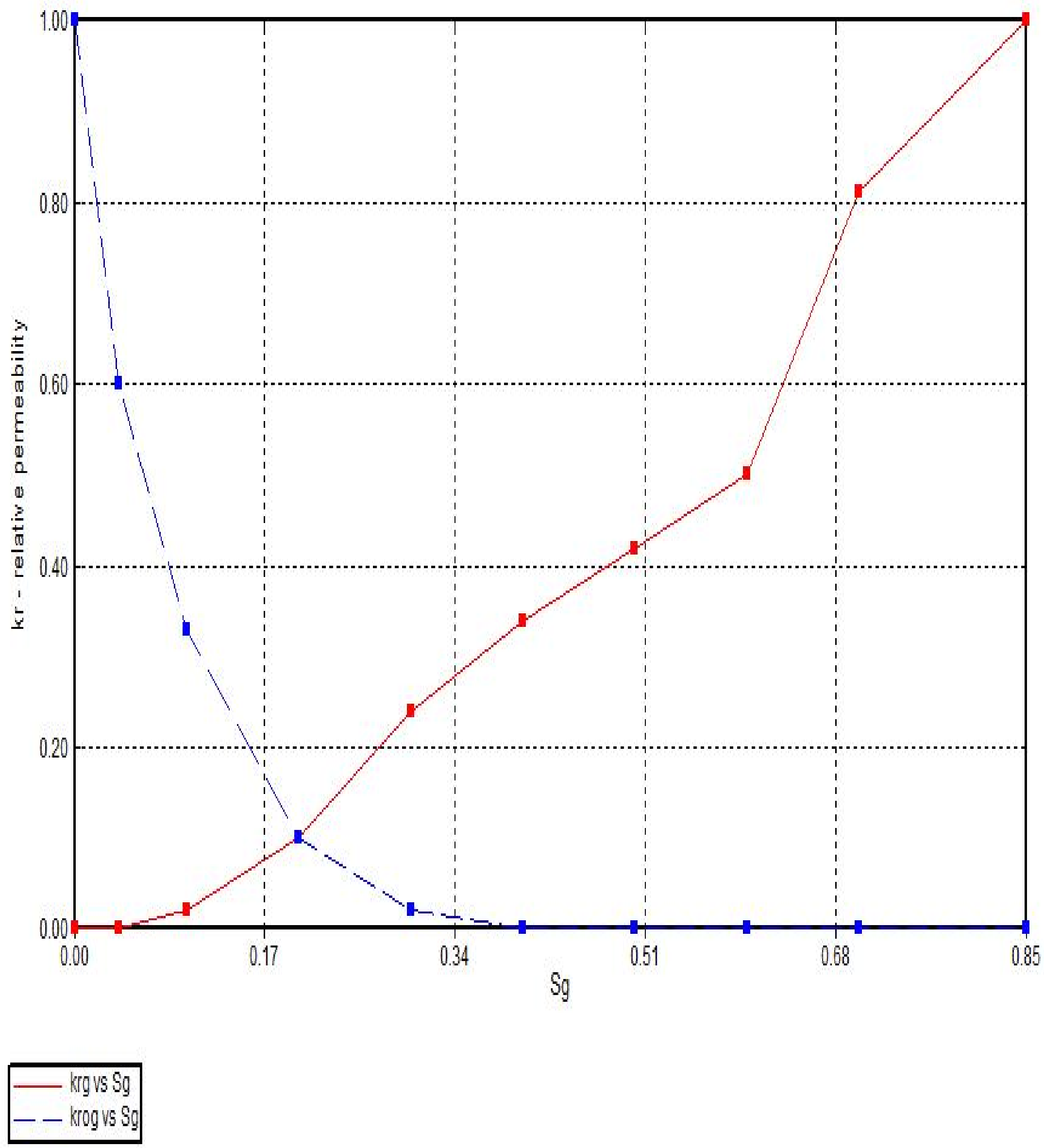

Figure 3.5. *Graph of Relative Permeability vs Gas Saturation (Generated from CMG builder)*

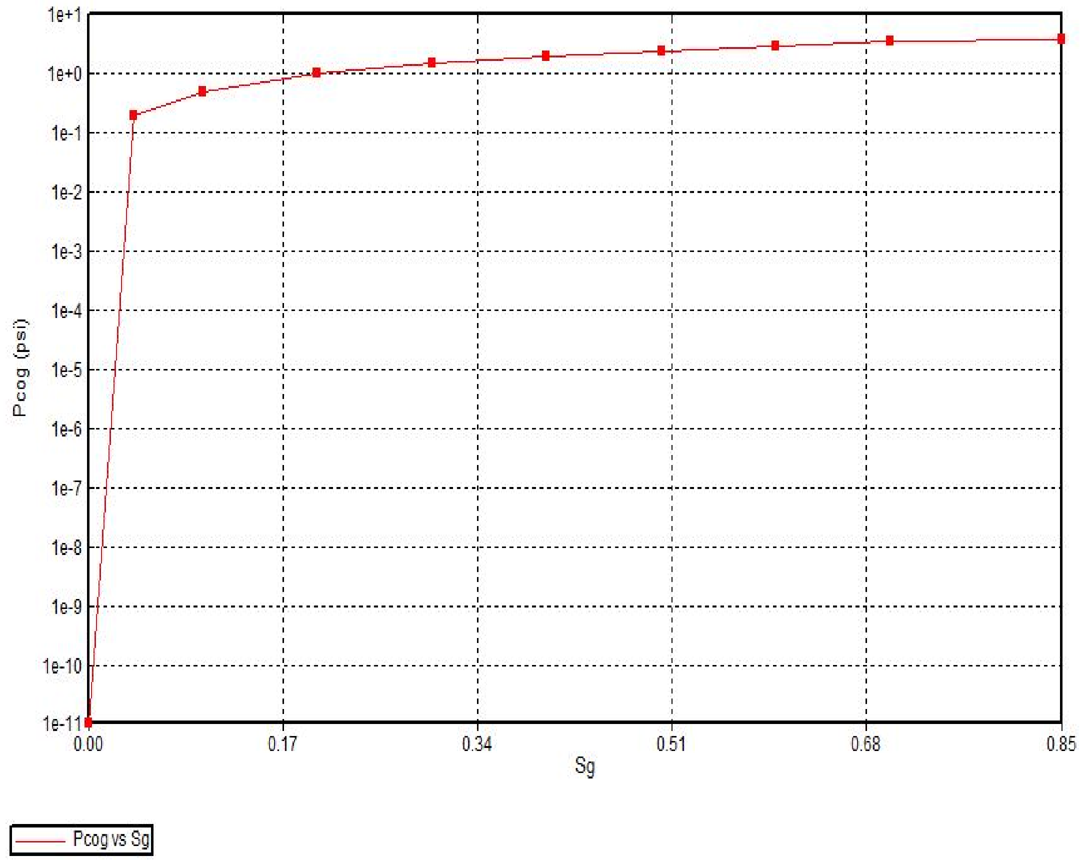

Figure 3.6. *Graph of Gas Oil Capillary Pressure vs Gas Saturation (Generated from CMG builder)*

The well pattern used is one injector and one producer in a period of 10 years (3652days), different polymer molarity of 0.15, 1.5, 3.0, and 4.5M were injected to get a better recovery factor and a 3D view showing the Grid top is shown in Figure 3.7 below

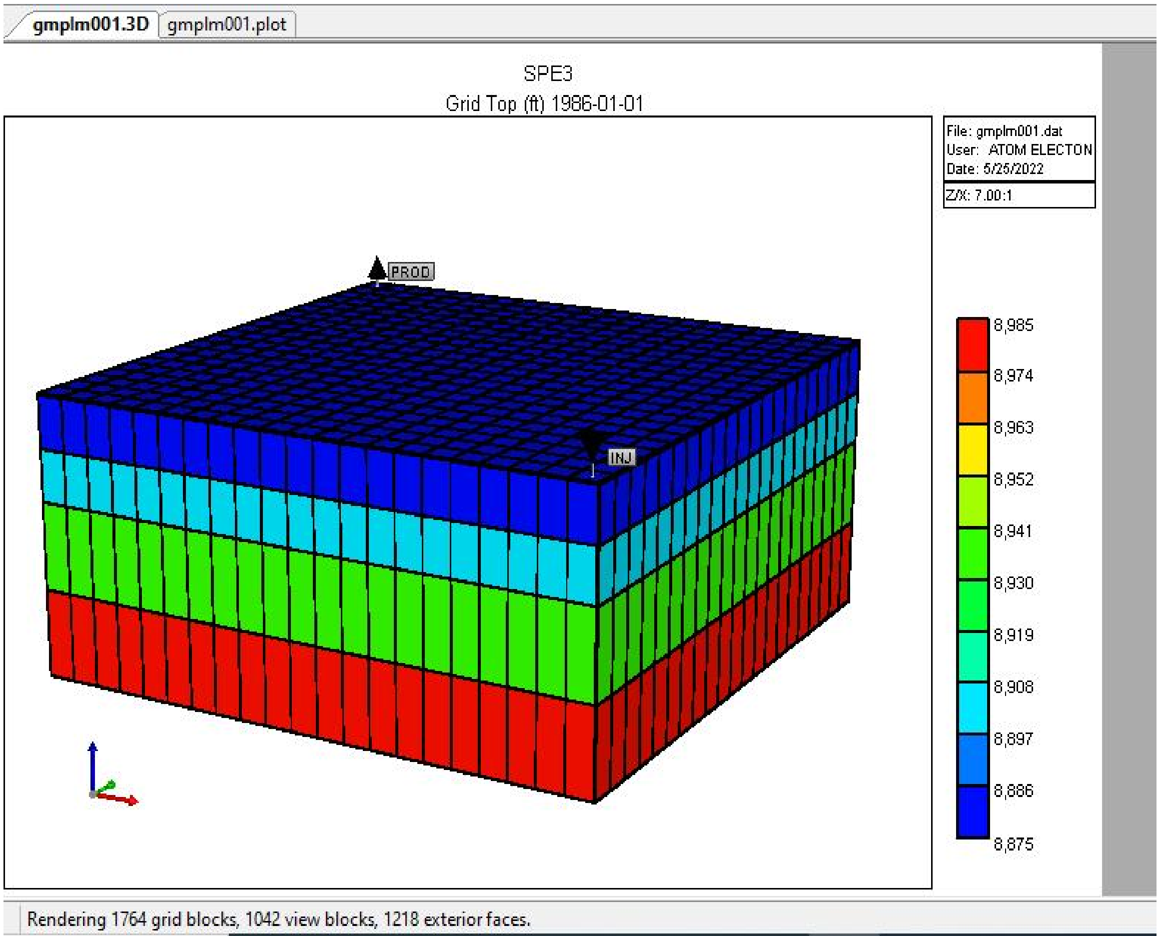

Figure 3.7. *A 3D View Showing the Grid Top (Generated from CMG builder).*

Primary Recovery, Secondary, and Polymer flooding

In primary recovery, reservoir rock and fluid properties simulation analysis was run using CMG (GEM), but, In this scenario, there is no polymer injection and no water flood. With the same reservoir rock and fluid properties a simulation analysis was run using CMG (GEM), but, in this scenario, there was no injection of polymer, but only water flood. Polymer flooding was use to increase the recovery factor using different molarity of (0.15, 1.5, 3.0 and 4.5M).

#	Item	Units	Value
1	Total Bulk Reservoir ...	RES FT3	1.01606E+09
2	Total Pore Volume,	RES FT3	1.32102E+08
3	Total Hydrocarbon Po...	RES FT3	1.11742E+08
4	Original Oil in Place, ...	STD BBL	1.70011E+07
5	Original Gas in Place, ...	STD FT3	6.20779E+09

Figure 3.8**.** *Total Resources in Place in the Simulation Model (Generated by CMG Builder)*

CHAPTER IV

Results and Discussions

After creating the reservoir model and history matching it, the results were analyzed and were made to optimize the production of the wells. In this chapter, each case is going to be checked to see if it optimized the production as intended. The experiment was run for 10years and the results were desirable.

Gas Oil Ratio

Under the standard condition, the gas oil ratio (GOR) simply means the ratio of the amount quantity of gas and oil. Rs is the abbreviation .

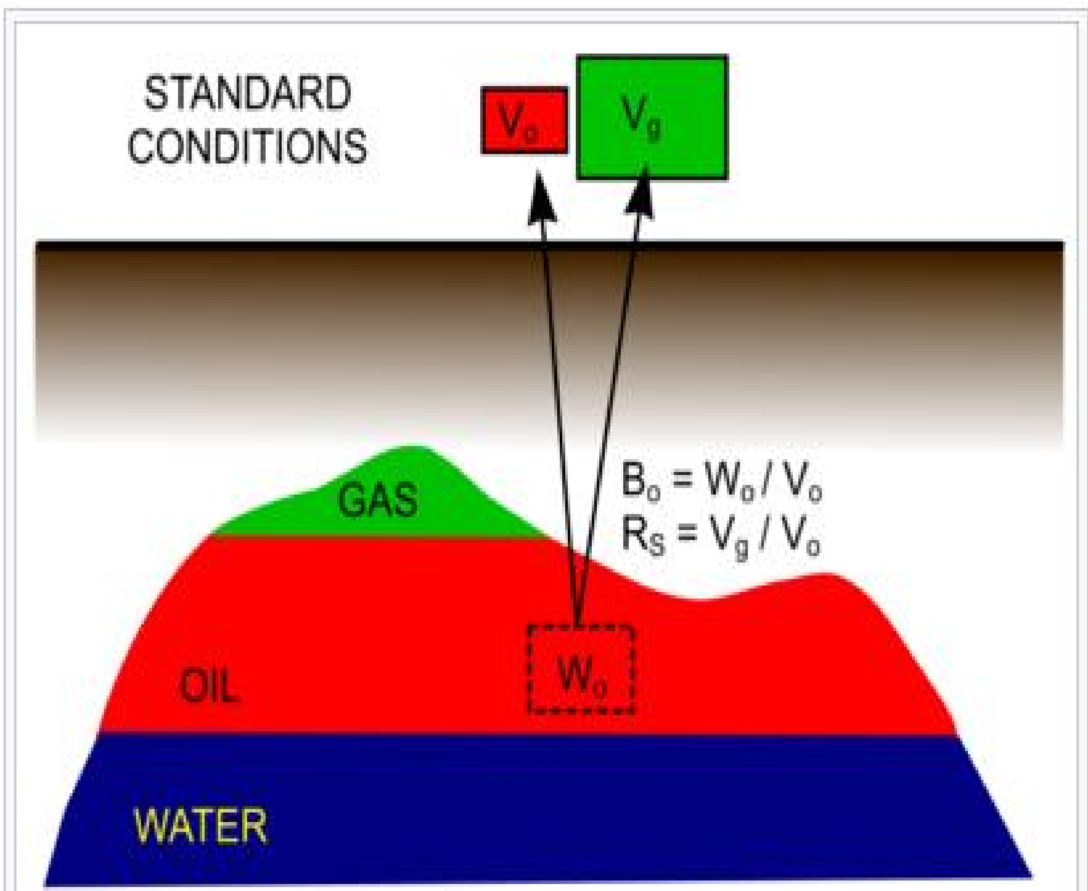

Figure 4.1. *Formation Volume Factor and Gas/Oil Ratio for Oil (Al-Shalabi et al., 2017)*

Graph with CMG Software

- The graphs below are the graph of gas oil ratio (GOR), water-oil ratio (WOR), oil rate, water rate, fluid rate, cumulative (WOR), recovery factor with four different molarity, cumulative oil, and recovery factor with five different molarity of polymer injection, waterflooding, and primary recovery.

- The graph of gas oil rate shows that primary recovery is higher than polymer injection, and waterflooding in the early days. Note that the polymer injection of 4.5M was use in this graph

- The graph of water oil ratio shows that waterflooding is higher than polymer injection, and primary recovery.

- The graph of oil rate shows that polymer injection is higher than waterflooding and primary recovery.

- The graph of water rate shows that waterflooding is higher than polymer injection, and primary recovery.

- The graph of fluid rate shows that primary recovery is higher in the early 60days but, in 3652days polymer, injection is higher than the waterflooding and primary recovery.

- The cumulative oil and recovery factor shows that in polymer injection its higher compare to waterflooding and primary recovery

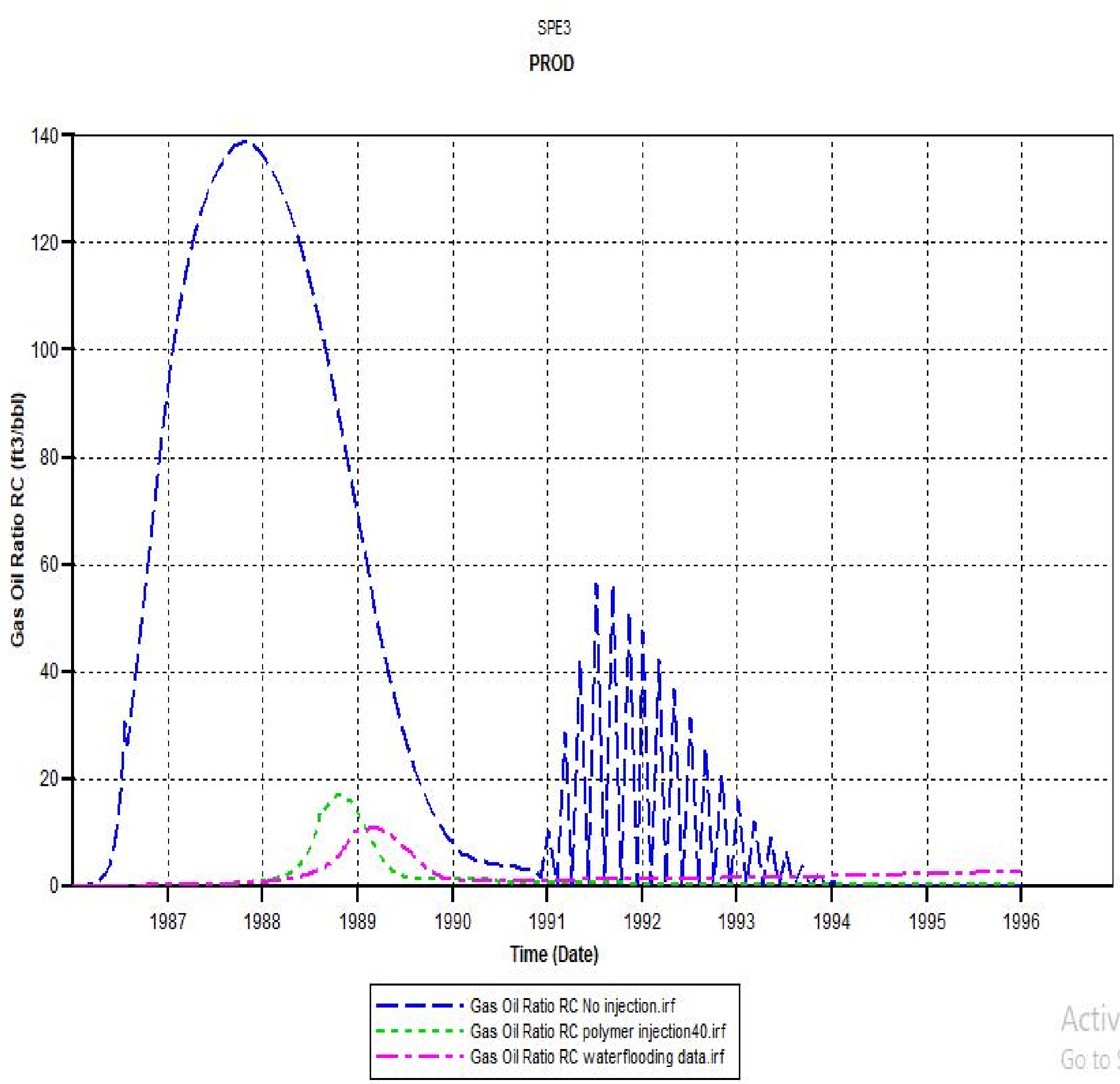

Figure 4.2. *The Graph of Gas Oil Ratio of Polymer Injection, Waterflooding, and Primary Recovery*

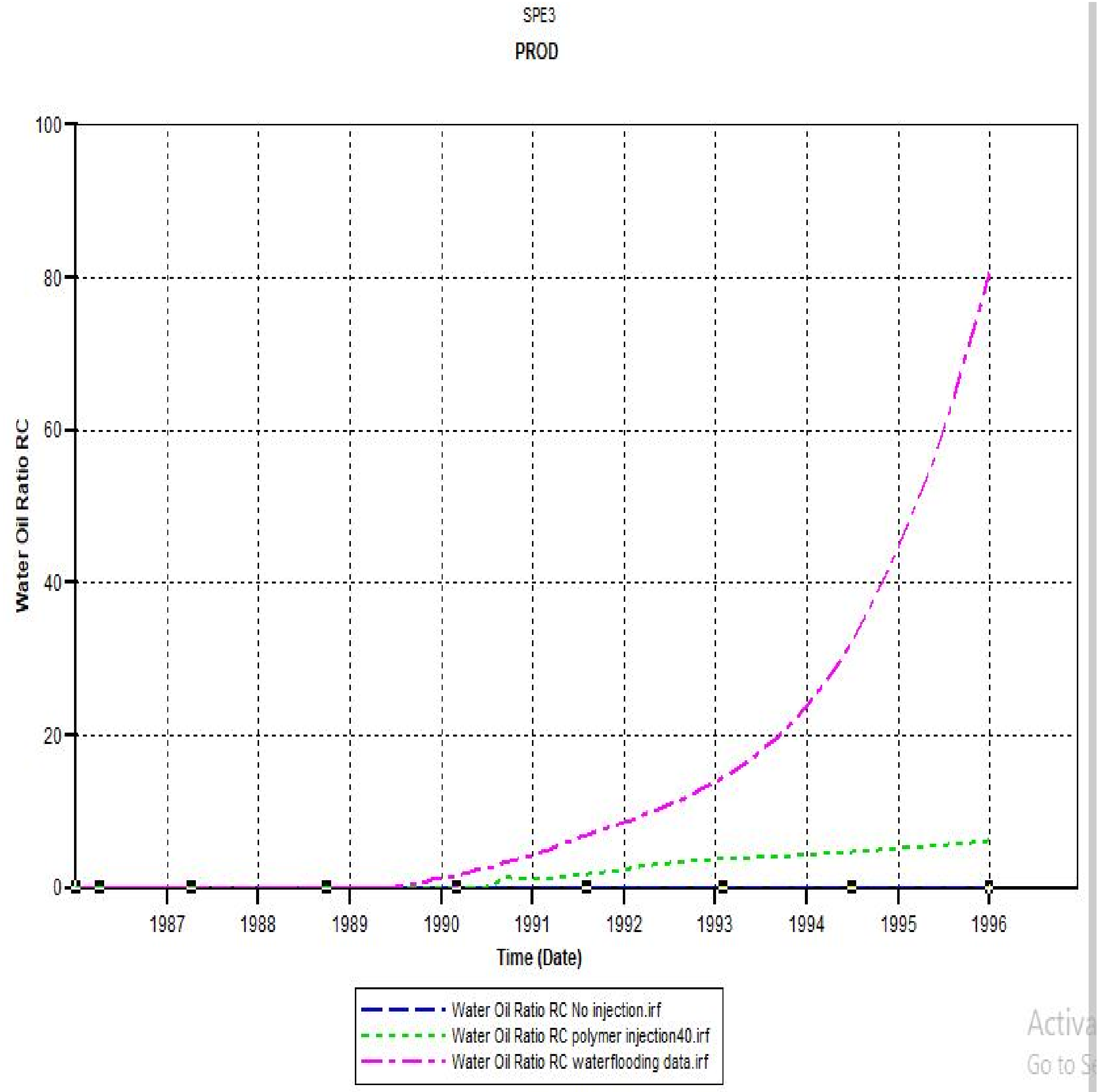

Figure 4.3. *The Graph of Water Oil Ratio of Polymer Injection, Waterflooding, and Primary Recovery*

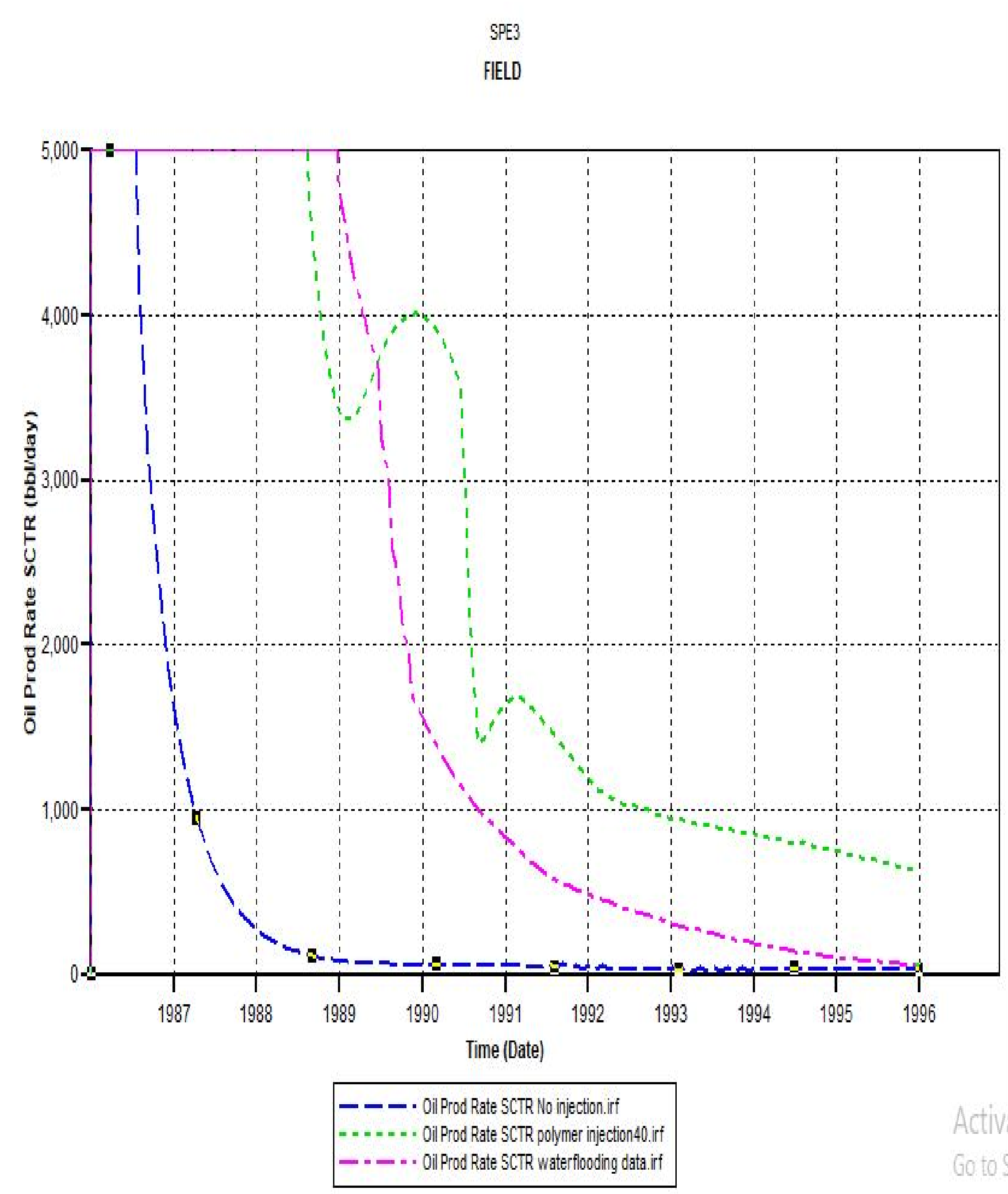

Figure 4.4. *The Graph of Oil Rate of Polymer Injection, Waterflooding, and Primary Recovery*

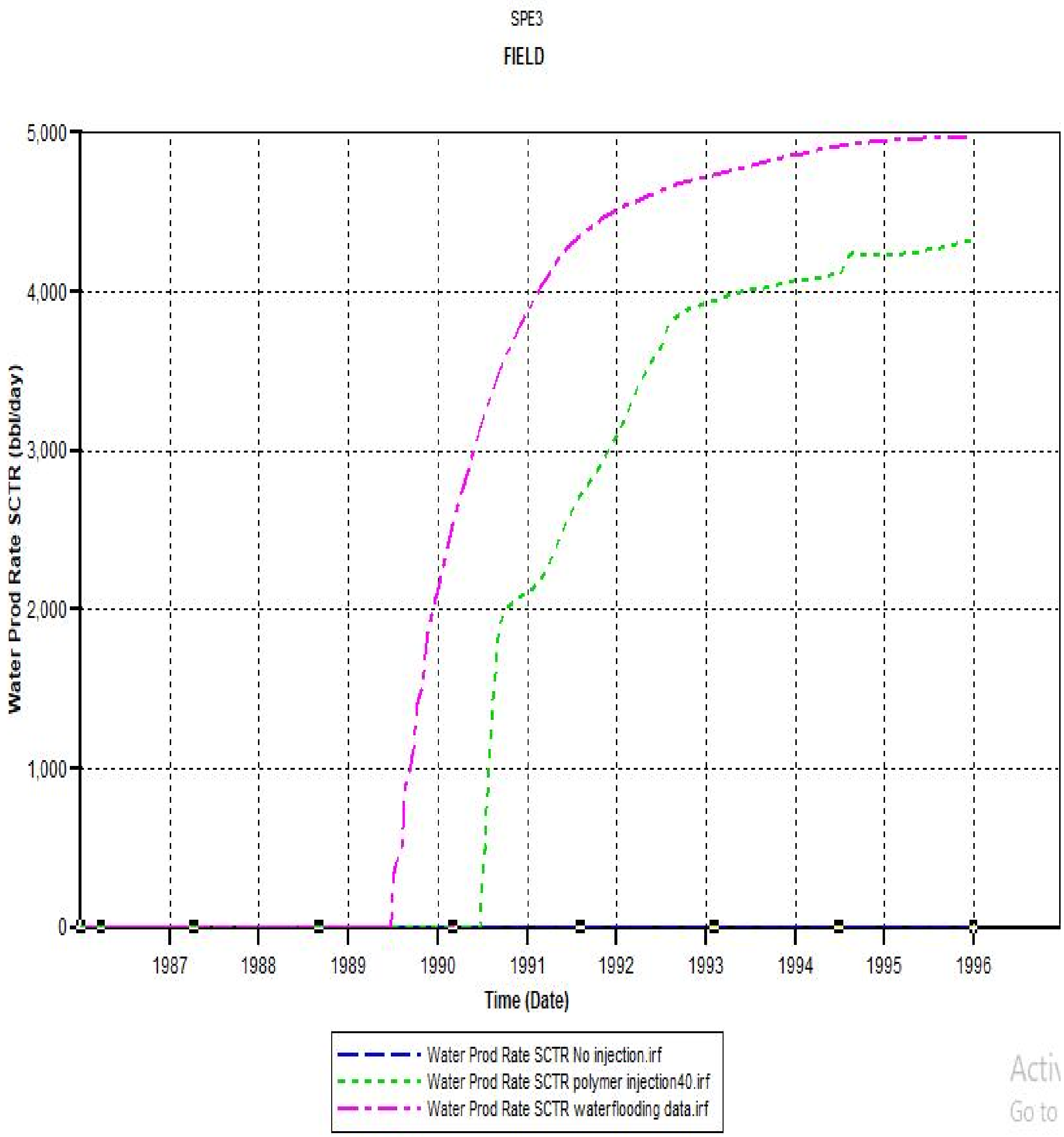

Figure 4.5. *The Graph of Water Rate of Polymer Injection, Waterflooding, and Primary Recovery*

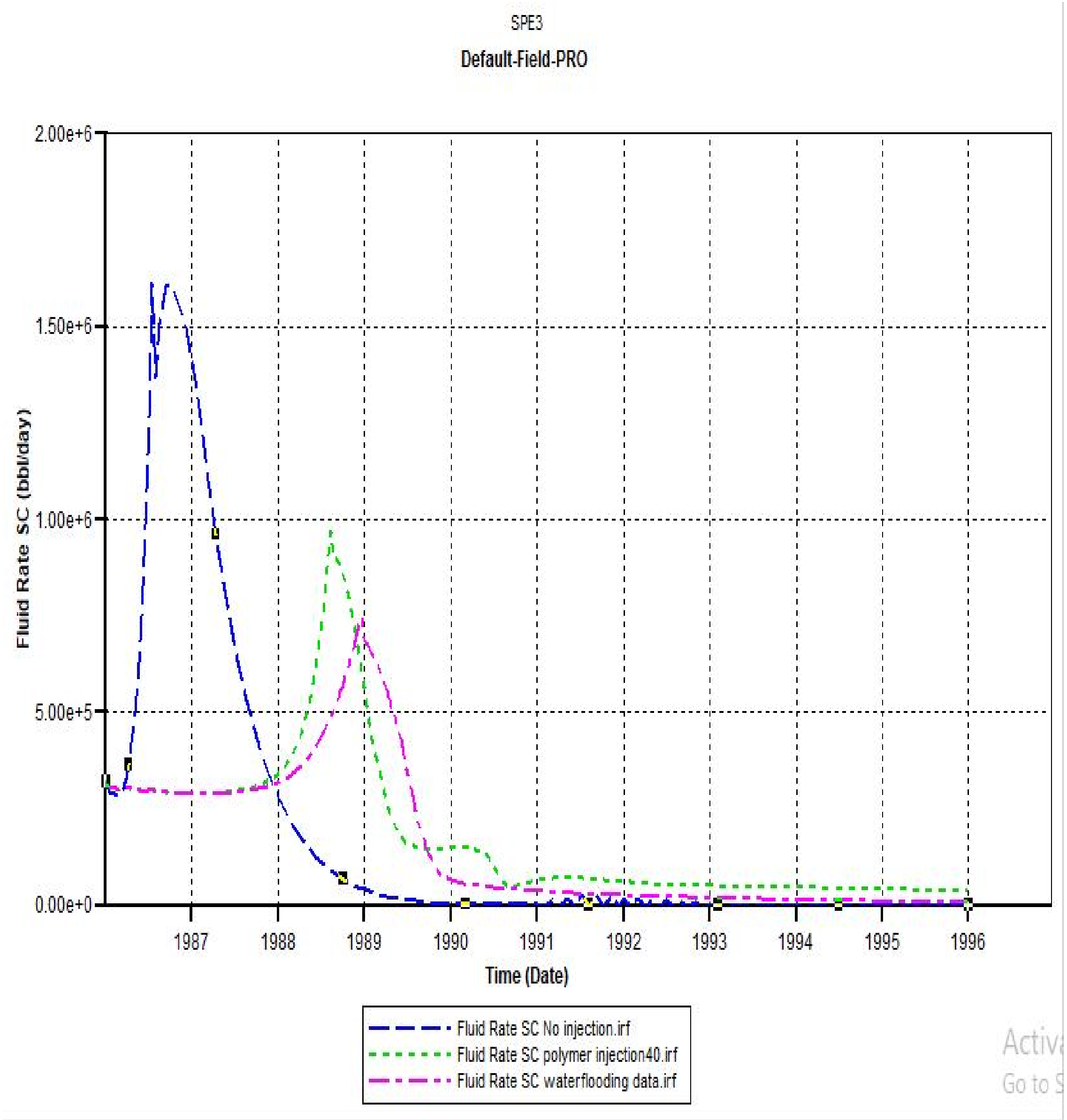

Figure 4.6. *The Graph of Fluid Rate of Polymer Injection, Waterflooding, and Primary Recovery*

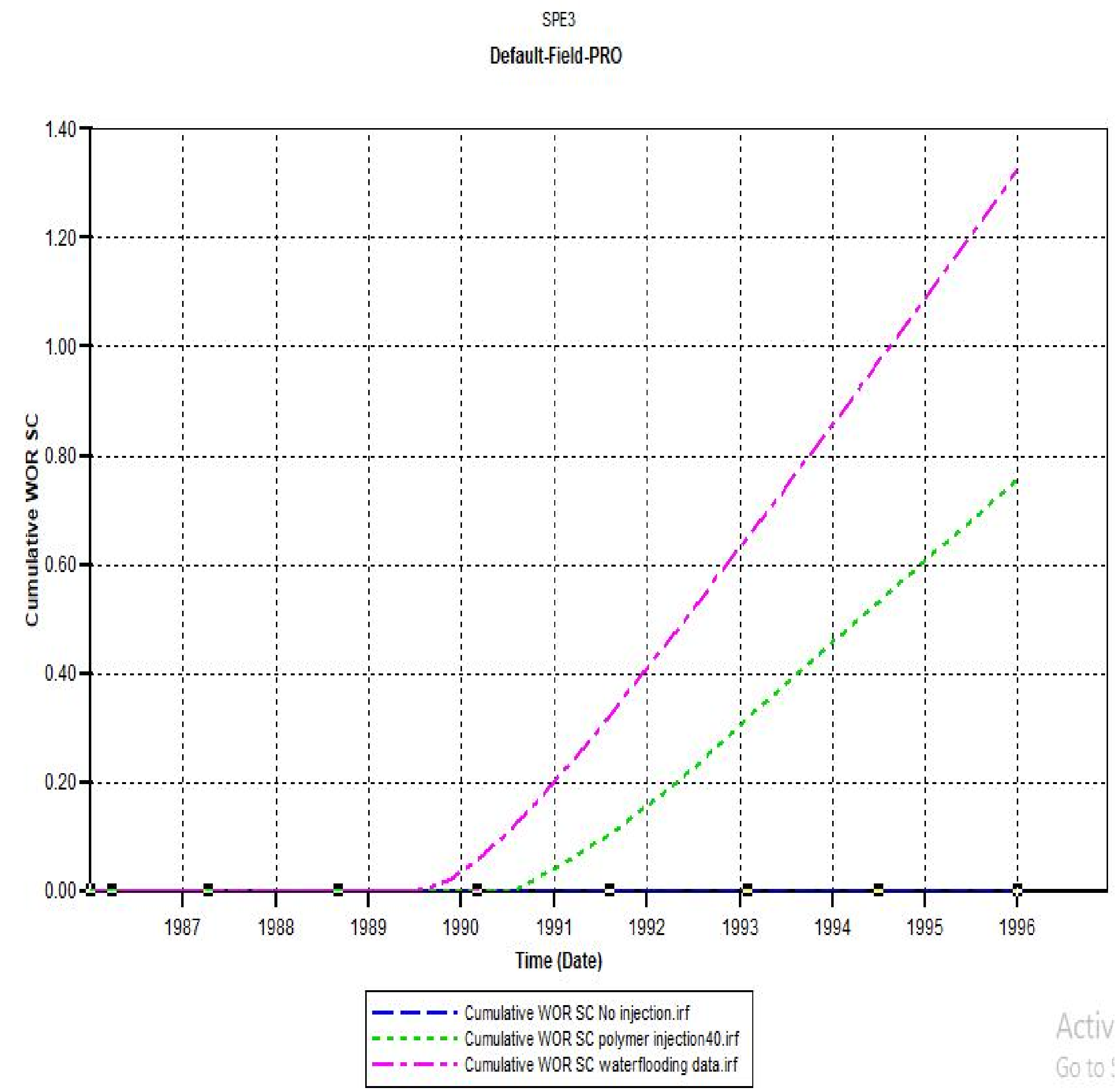

Figure 4.7**.** *The Graph of Cumulative (WOR) of Polymer Injection, Waterflooding, and Primary Recovery*

Oil Recovery Factor

The main aim of this research is to increase the recovery factor, the recovery factor is in percentage and is the quantity of natural gas recovered from the original oil in place (OOIP).

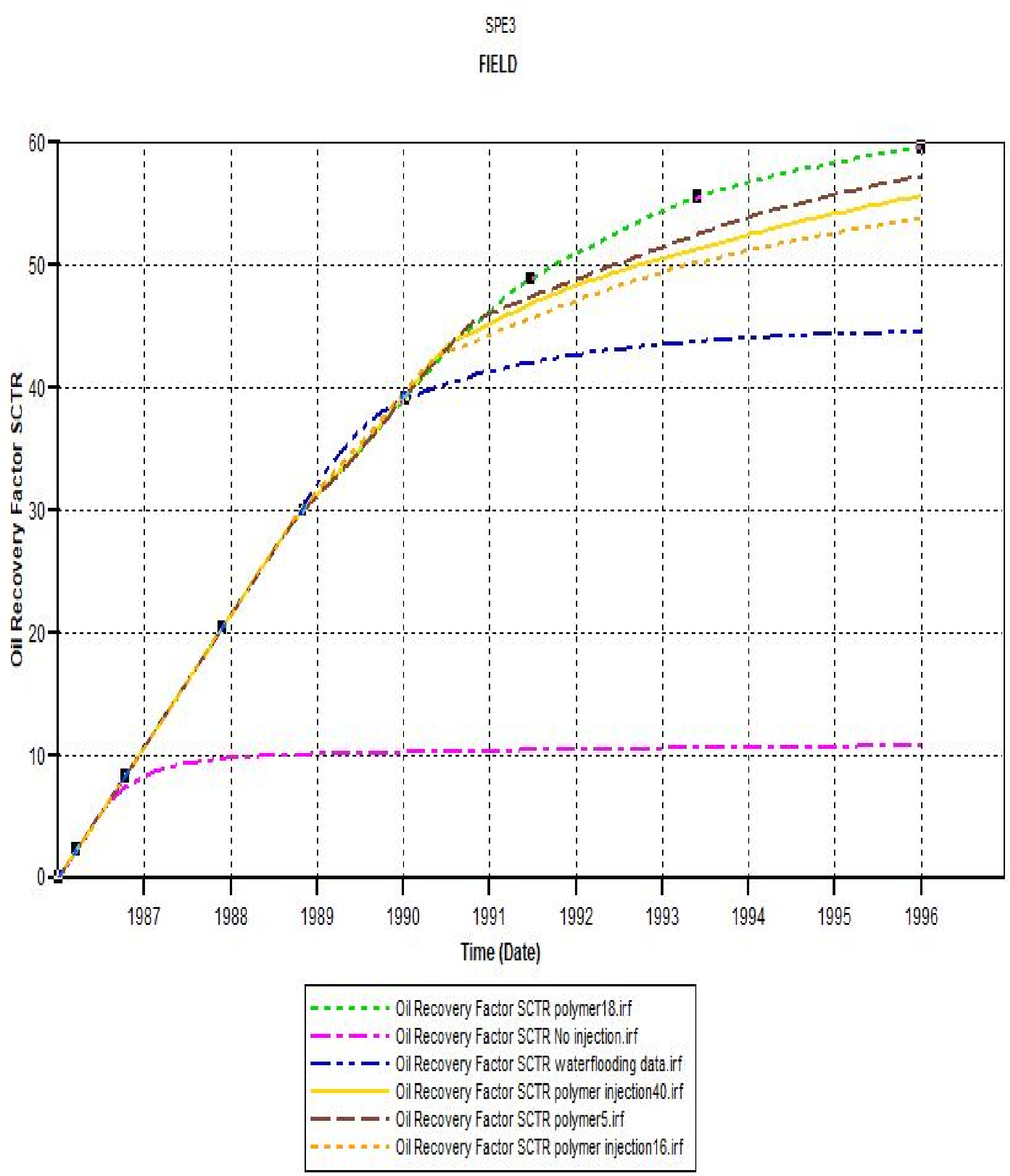

Figure 4.8. *The Graph of Recovery Factor in 4 Polymer Injection, Waterflooding, and Primary Recovery*

Cumulative Oil

Cumulative oil production is the sum of the quantity of hydrocarbon recovered in the reservoir.

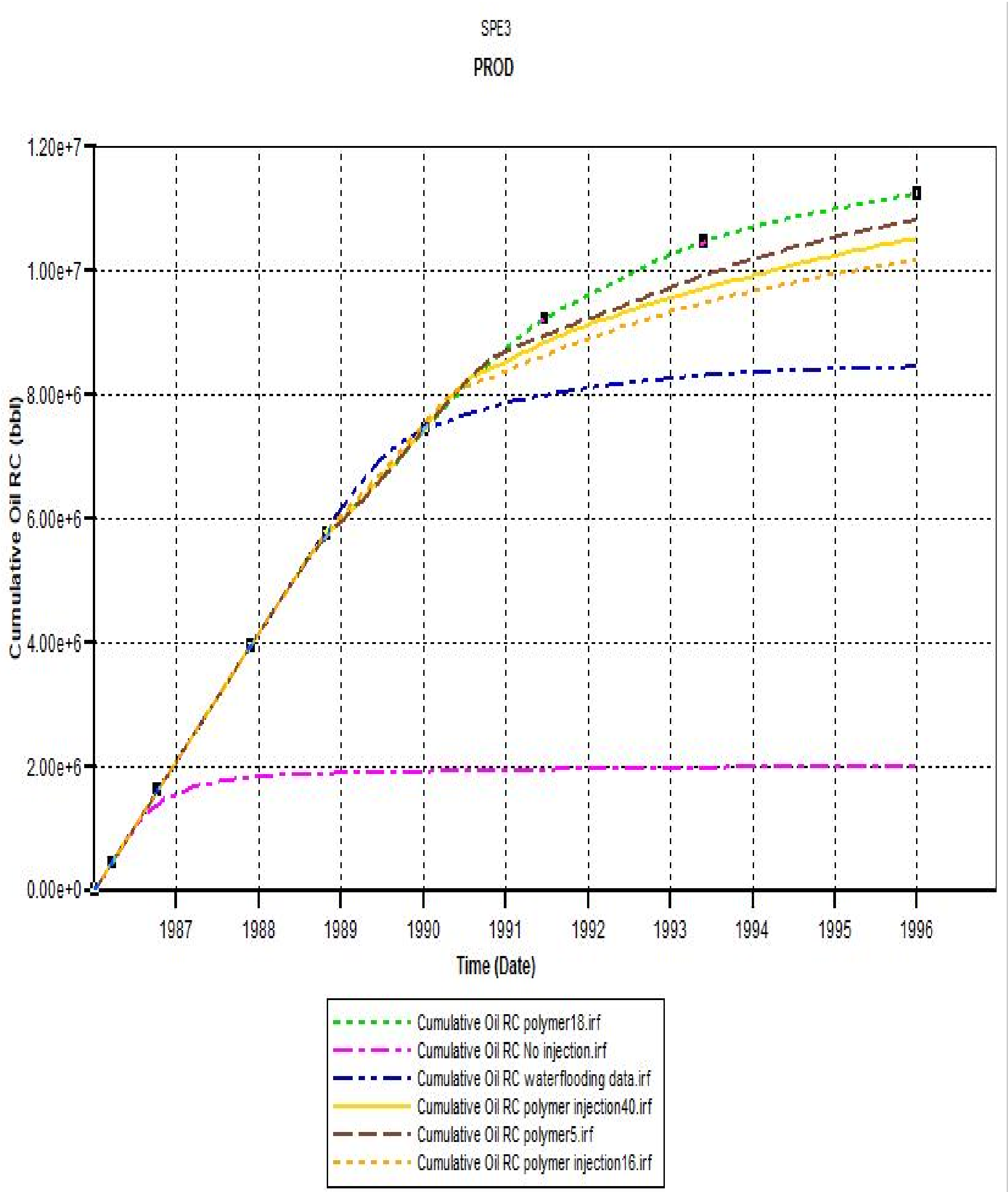

Figure 4.9. *The Graph of Cumulative Oil in Polymer Injection, Waterflooding, and Primary Recovery*

Table 4.1.

Recovery Factor and Cumulative Oil Result of Polymer Injection, Waterflooding, and Primary Recovery

	Scenario	Recovery Factor (%)	Cumulative Oil (bbl/day)
1	No Injection of polymer	11	2.01346E+006
2	Waterflooding	45	8.44819E+006
3	Polymer Injection (0.15M)	54	1.01762E+007
4	Polymer Injection (1.5M)	56	1.05346E+007
5	Polymer Injection (3.0M)	57	1.08328E+007
6	Polymer Injection (4.5M)	60	1.12440E+007

The maximum recovery factor of primary recovery is 11%, waterflooding is 45%, and polymer injection is 60% after the simulation analysis.

Below shows the recovery factor of 5 different polymer molarity, waterflooding, and primary recovery. It was observed that the polymer molarity of 4.5 and 6.0M has the same recovery factor.

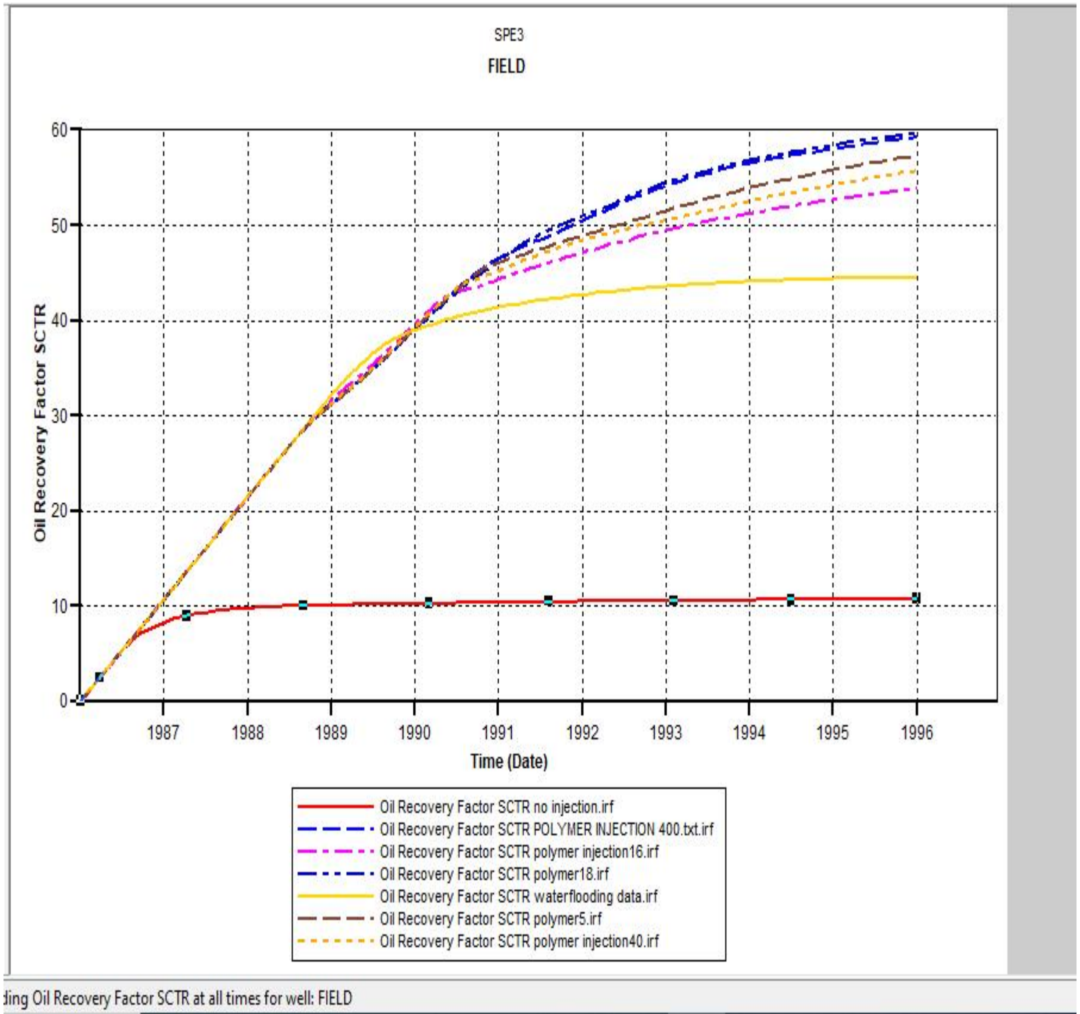

Figure 4.10. *The Graph of Oil Recovery Factor in 5 Polymer Injection, Waterflooding, and Primary Recovery*.

CHAPTER V
Conclusions

With polymer injection, oil is been recovered more than the waterflooding and primary recovery. The more you increase the polymer concentration/molarity that will be added to the water in the reservoir formation, the more the water becomes viscous and that will help provide better sweep efficiency which will result in better recovery. Note, that the essence of this research is to increase the recovery factor and improvement of cumulative oil using different polymer molarity injection and compare it with the recovery factor of waterflooding if, spending money to buy polymer is worth it when water is cheaper than polymer. It is observe that the viscosity of the water increase for a better sweep efficiency and more favorable mobility on the field using CMG as the simulator. Hydrolyzed polyacrylamide (HPAM), is the polymer used due to its favorable cost availability and viscoelasticity properties on it which help to get a better recovery factor compare to both primary and secondary recovery that can only recover an average of 30% of original oil in place (OOIP).

Some factors are been put in place to help improve the Ghawar oil production in the field and these factors are; injecting high polymer molarity and molecular weight. Petroleum engineers discovered that increase in the injection rate, will result to the decrease in the oil recovery, and in many literature reviews, observation shows that the increase in the permeability in the production data will result in the increase in oil recovery by polymer solution. Key parameters that were prioritized for optimization in this work include well spacing, polymer injection duration, and the increase in molarity. In polymer flooding with a peripheral injection well configuration, conversion of the producer to the injector at a later stage indicates to provide a good sweep improvement toward the inner producers. This research work presents the effectiveness of the HPAM used. The polymer flooding experiments were performed to evaluate the flooding potential. These bio-polymer has the ability to improve/recover entrapped hydrocarbon, in these research, maximum recovery factor of 54%, 56% 57% and 60% was obtained.

Findings and Recommendations for Further Research

For a better recovery factor and cumulative oil, It is advisable we introduce polymer injection and use HPAM because of the availability and cost, increase the permeability data, inject more production well, allow it for long period of time and also increase the polymer molarity to get a better Recovery factor.

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Appendices

Appendix A: Simulation Data File for Polymer

```
GMPLM001.DAT: Polymer slug injection in a light oil reservoir      **
**------------------------------------------------------------------**
**------------------------------------------------------------------**
**                                                 **
** FILE:  GMPLM001.DAT                                               **
**                                                 **
** MODEL: CART 21x21x4 GRID                   4 COMPONENTS        **
**       FIELD UNITS                 QUARTER 5-SPOT PATTERN       **
**                                ONE-INJECTOR AND       **
**                                  ONE PRODUCER       **
**                                                 **
**------------------------------------------------------------------**
**                                                 **
** Polymer injection in a light oil reservoir in a quarter of a       **
** 5-spot pattern.                                       **
**                                                 **
** The oil and water viscosities at reservoir conditions are 1.5 cp   **
** and 0.34 cp respectively. A polymer slug with concentartion small  **
** enough to alter the aqueous phase viscosity to around 1.5 cp is    **
** injected for a period of 6 months. This is followed by water       **
** injection for a period of 6 mnoths. The cycle is repeated several  **
```

```
** times for a period of 10 years.                                 **
**                                                                 **
** In a companion dataset gmplm002.dat, no polymer is injected - only **
** water injection is done. Comparision of results from the two      **
** data sets shows inremental oil recovery due to polymer slug       **
** injection over water-flood.                                        **
**                                                                 **
**-----------------------------------------------------------------**
** CONTACT CMG at (403)531-1300 or support@cmgl.ca                  **
**-----------------------------------------------------------------**

*RESULTS *SIMULATOR *GEM
*TITLE1 'SPE3'
*TITLE2 'Polymer Injection'
*TITLE3 'Modified Relative Permeabilities'
*CASEID 'CASE 1'
*INUNIT *FIELD

*WSRF   *GRID  1
*WSRF   *WELL  1
*WRST   0
*WPRN   *ITER  *BRIEF
*WSRF   *WELL   1
*OUTSRF *GRID *SO *SW  *SG  *PRES *MOLALITY 'POLYMER' *VISW *VISO
```

```
*OUTSRF *RES *ALL

**------------------------- RESERVOIR DATA --------------------------

*GRID  *CART  21  21  4

*DI  *CON 120.

*DJ  *CON 120.

*DK  *KVAR  50.  50.  30.  30.

*DEPTH 1 1 1 9010

**  0 = null block, 1 = active block

NULL CON            1

*POR  *CON  0.13

*PERMI *CON 150

PERMJ EQUALSI

PERMK EQUALSI * 0.1

**  0 = pinched block, 1 = active block

PINCHOUTARRAY CON            1

*CPOR  4.0E-06

*PRPOR  3550.0


** ------------------------ FLUID COMPONENT DATA --------------------


*MODEL   *PR

*NC    4    4

*TRES       100.000

*PVC3  1.2000000E+00
```

```
*COMPNAME
        'C1'        'C2'        'C3'        'FC35'
*SG       3.0000000E-01  3.5600000E-01  5.0700000E-01  9.2000000E-01
*TB      -2.5861000E+02 -1.2757000E+02 -4.3690000E+01  9.0833000E+02
*PCRIT    4.5400000E+01  4.8200000E+01  4.1900000E+01  8.9100000E+00
*VCRIT    9.9000000E-02  1.4800000E-01  2.0300000E-01  1.5890000E+00
*TCRIT    1.9060000E+02  3.0540000E+02  3.6980000E+02  9.0590000E+02
*AC       8.0000000E-03  9.8000000E-02  1.5200000E-01  1.1786420E+00
*MW       1.6043000E+01  3.0070000E+01  4.4097000E+01  4.4500000E+02
*HCFLAG   0              0              0              0
*BIN
         2.6890022E-03
         8.5370405E-03  1.6620489E-03
         1.1668844E-01  8.7485776E-02  6.6882706E-02
*VSHIFT  -1.5386050E-01 -1.0210346E-01 -7.3300940E-02  7.7033540E-02
*VISCOR *HZYT
*MIXVC    1.0000000E+00
*VISVC    9.9000000E-02  1.4800000E-01  2.0300000E-01  2.0300000E+00
*VISCOEFF   1.0230000E-01  2.3364000E-02  5.8533000E-02 -4.0758000E-02
         9.3324000E-03
*OMEGA    4.5723553E-01  4.5723553E-01  4.5723553E-01  4.5723553E-01
*OMEGB    7.7796074E-02  7.7796074E-02  7.7796074E-02  7.7796074E-02
*PCHOR    7.7000000E+01  1.0800000E+02  1.5030000E+02  9.9030000E+02
*ENTHCOEF
```

```
-5.5811400E+00  5.6483400E-01 -2.8297300E-04  4.1739900E-07
-1.5255760E-10  1.9588570E-14
-7.6005000E-01  2.7308800E-01 -4.2956000E-05  3.1281500E-07
-1.3898900E-10  2.0070230E-14
-1.2230100E+00  1.7973300E-01  6.6458000E-05  2.5099800E-07
-1.2474610E-10  1.8935090E-14
 0.0000000E+00 -1.4631650E-02  3.9919450E-04 -5.6319130E-08
 0.0000000E+00  0.0000000E+00

*DENWS 63.046
*CW    3.E-06
*REFPW 3600

** Model has one aqueous component
*NC-AQUEOUS 1
*COMPNAME-AQUEOUS
'POLYMER'

** 'POLYMER' is the name of the polymer-component that is in aqueous phase
*COMPNAME-POLYMER
'POLYMER'
*MW-AQUEOUS
22000.
```

** Use default aqueous phase viscosity model, i.e., *NONLIN1

*AQUEOUS-VISCOSITY *POLYMER

** Specify parameters for aqueous viscoisty

*AVISC-AQUEOUS 1.5

*BVISC-AQUEOUS 0.0

** Specify parameters for H2O component viscosity

*AVISC-H2O 0.34

*BVISC-H2O 0.

** Mixing rule parameters for aqueous phase viscosity

** component xlow xhigh

*VSMIXENDP 'POLYMER' 0 8.19808e-09

** parameters to generate weighting factors against aqueous phase mole fraction

*VSMIXFUNC 'POLYMER' 0 0.16243 0.32486 0.487104 0.541771 0.596487 0.677189 0.757892 0.838595 0.919297 1

*DERIVATIVEMETHOD *NUMERALL

** --------------------------- ROCK FLUID ------------------

*ROCKFLUID

*RPT 1

*SWT

```
** sw       krw     krow      pcow
0.151090    0.0    1.0       400.0
0.151230    0.0    0.99997   359.190
0.151740    0.0    0.99993   257.920
0.152460    0.0    0.99991   186.310
0.156470    0.0    0.999510   79.060
0.165850    0.0    0.996290   40.010
0.178350    0.0    0.991590   27.930
0.203350  0.000010   0.978830   20.400
0.253350  0.000030   0.943730   15.550
0.350000  0.000280   0.830230   11.655
0.352000  0.002292   0.804277    8.720
0.354000  0.004304   0.778326    5.947
0.356000  0.006316   0.752374    3.317
0.358000  0.008328   0.726422    1.165
0.360000  0.010340   0.700470    0.463
0.364395  0.015548   0.642258   -0.499
0.368790  0.020756   0.584046   -1.139
0.370000  0.022190   0.568020   -1.194
0.380000  0.035890   0.434980   -1.547
0.400000  0.069530   0.171430   -1.604
0.433450  0.087900   0.125310   -1.710
0.461390  0.104910   0.094980   -1.780
```

0.489320 0.123290 0.070530 -1.860

0.517250 0.143030 0.051130 -1.930

0.573120 0.186590 0.024640 -2.070

0.601060 0.210380 0.016190 -2.130

0.656930 0.261900 0.005940 -2.260

0.712800 0.318650 0.001590 -2.380

0.811110 0.430920 0.000020 -2.600

0.881490 0.490000 0.000000 -2.75

*SGT

** sl krg krog pcog

0.000000 0.0000 1.00 0.0

0.040000 0.0000 0.60 0.2

0.100000 0.0220 0.33 0.5

0.200000 0.1000 0.10 1.0

0.300000 0.2400 0.02 1.5

0.400000 0.3400 0.00 2.0

0.500000 0.4200 0.00 2.5

0.600000 0.5000 0.00 3.0

0.700000 0.8125 0.00 3.5

0.848910 1.0000 0.00 3.9

**---INITIAL CONDITION---

*INITIAL

```
*VERTICAL *BLOCK_CENTER  *WATER_OIL_GAS
*DATUMDEPTH 9035.
*ZOIL 0.30 0.22 0.12 0.36
*ZGAS 0.20 0.22 0.12 0.36

REFPRES
  3600.

REFDEPTH
  9035.

DWOC
  9950.

DGOC
  8800.
*MOLALITY-AQUEOUS 0.0

**-------------------------------------------------NUMERICAL-----------
*NUMERICAL
NORM PRESS 145.04
NORM SATUR 0.05
NORM GMOLAR 0.05
MAXCHANGE PRESS 500
```

```
MAXCHANGE SATUR 0.8

MAXCHANGE GMOLAR 0.8

AIM STAB AND-THRESH 1 0.001

CONVERGE MAXRES 0.0001


**-------------------------------------------------WELL DATA-----------

*RUN

*DATE 1986 1 1

DTWELL 0.1

    *DTMIN    0.1E-06

    *DTMAX  31

**      *WELL 1 'PROD'

**

WELL  'PROD'

PRODUCER 'PROD'

OPERATE  MAX  STO  5000.0  CONT

OPERATE  MIN  BHP  500.0  CONT

**      *WELL 2 'INJ'

**

WELL  'INJ'

                ** Inject polymer solution with 'POLYMER' molality of 4.54E-07

INJECTOR 'INJ'

INCOMP  AQUEOUS  0.0  0.0  0.0  0.0  4.54e-007

OPERATE  MAX  STW  5000.0  CONT
```

```
OPERATE  MAX  BHP  6000.0  CONT
**        rad  geofac  wfrac  skin
GEOMETRY  K  1.0  0.34  1.0  0.0
    PERF      GEO  'PROD'
** UBA           ff        Status  Connection
   1 1 4        1.0  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   1 1 3        1.0  OPEN   FLOW-TO  1
   1 1 2        1.0  OPEN   FLOW-TO  2
   1 1 1        1.0  OPEN   FLOW-TO  3
**        rad  geofac  wfrac  skin
GEOMETRY  K  1.0  0.34  1.0  0.0
    PERF      GEO  'INJ'
** UBA             ff        Status  Connection
   21 21 4        1.0  OPEN   FLOW-FROM  'SURFACE'  REFLAYER
   21 21 3        1.0  OPEN   FLOW-FROM  1
   21 21 2        1.0  OPEN   FLOW-FROM  2
   21 21 1        1.0  OPEN   FLOW-FROM  3
AIMWELL WELLNN

*DATE 1986 6 1
INJECTOR 'INJ'
INCOMP  WATER
*DATE 1988 1 1
INJECTOR 'INJ'
```

```
INCOMP  AQUEOUS  0.0  0.0  0.0  0.0  4.5
*DATE 1988 6 1
INJECTOR 'INJ'
INCOMP  WATER
*DATE 1990 1 1
INJECTOR 'INJ'
INCOMP  AQUEOUS  0.0  0.0  0.0  0.0  4.5
*DATE 1990 6 1
INJECTOR 'INJ'
INCOMP  WATER
*DATE 1992 1 1
INJECTOR 'INJ'
INCOMP  AQUEOUS  0.0  0.0  0.0  0.0  4.5
*DATE 1992 6 1
INJECTOR 'INJ'
INCOMP  WATER
*DATE 1994 1 1
INJECTOR 'INJ'
INCOMP  AQUEOUS  0.0  0.0  0.0  0.0  4.5
*DATE 1994 6 1
INJECTOR 'INJ'
INCOMP  WATER
*DATE 1996 1 1
*STOP
```

RESULTS SPEC 'Permeability J'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'All Layers (Whole Grid)'

RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'

RESULTS SPEC LAYERNUMB 0

RESULTS SPEC PORTYPE 1

RESULTS SPEC EQUALSI 0 1

RESULTS SPEC SPECKEEPMOD 'YES'

RESULTS SPEC STOP

RESULTS SPEC 'Permeability K'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'All Layers (Whole Grid)'

RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'

RESULTS SPEC LAYERNUMB 0

RESULTS SPEC PORTYPE 1

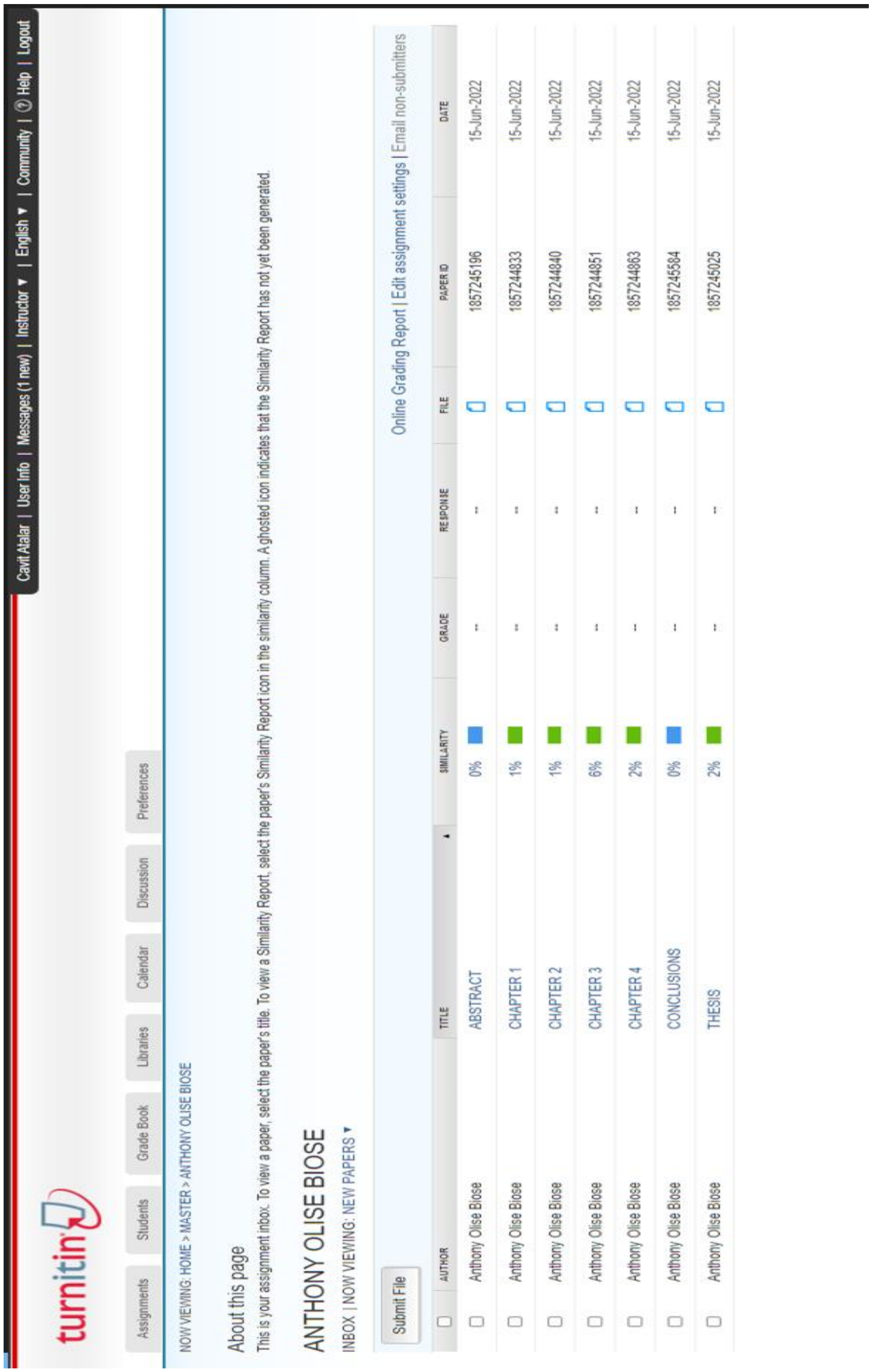
RESULTS SPEC EQUALSI 1 0.1

RESULTS SPEC SPECKEEPMOD 'YES'

RESULTS SPEC STOP

Appendix B

Turnitin Similarity Report



AUTHOR	TITLE	SIMILARITY	GRADE	RESPONSE	FILE	PAPER ID	DATE
Anthony Olise Biose	ABSTRACT	0%	--	--		1857245196	15-Jun-2022
Anthony Olise Biose	CHAPTER 1	1%	--	--		1857244833	15-Jun-2022
Anthony Olise Biose	CHAPTER 2	1%	--	--		1857244840	15-Jun-2022
Anthony Olise Biose	CHAPTER 3	6%	--	--		1857244851	15-Jun-2022
Anthony Olise Biose	CHAPTER 4	2%	--	--		1857244863	15-Jun-2022
Anthony Olise Biose	CONCLUSIONS	0%	--	--		1857245584	15-Jun-2022
Anthony Olise Biose	THESIS	2%	--	--		1857245025	15-Jun-2022

Appendix C

Ethical Approval Letter

YAKIN DOĞU ÜNİVERSİTESİ

ETHICAL APPROVAL DOCUMENT

Date: 29/06/2022

To the **Institute of Graduate Studies**

The research project titled **"NUMERICAL INVESTIGATION OF POLYMER FLOODING IN GHAWAR FIELD, SAUDI ARABIA''** has been evaluated. Since the researcher will not collect primary data from humans, animals, plants or earth, this project does not need through the ethics committee.

Title: Prof. Dr.

Name Surname: Cavit ATALAR

Signature:

Role in the Research Project: Supervisor