PRINCE IYKE OJEH

ANALYZATION OF THE EFFECT OF POLYMER INJECTION IN AN OIL RESERVOIR, BRENT FIELD, UK

MASTER THESIS

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NEAR EAST UNIVERSITY

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DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

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Approval

We certify that we have read the thesis submitted by Prince Iyke OJEH titled **"Analyzation of the Effect of Polymer Injection in an Oil Reservoir, Brent Field, UK"** 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.

Prince Iyke OJEH

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Prince Iyke OJEH

Abstract

Analyzation of the Effect of Polymer Injection in an Oil Reservoir, Brent Field UK

OJEH, Prince Iyke

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Most hydrocarbons cannot be recovered using basic recovery techniques. More hydrocarbons from the reservoir are recovered using secondary and tertiary recovery techniques like polymer. Chemical injection techniques like polymer injection have been used for several years. Increased water viscosity (i.e., decreased injected phase mobility) and improved oil sweep efficiency inside reservoir rock are achieved by the use of polymer injection.

This research aims to focus on the mechanisms involved in the analyzation of the effect of polymer injection in an oil reservoir, mainly the heavy oil, by performing simulations using CMG STAR, compare the results from various scenarios to find the one with the best recovery factor and cumulative oil recovery(bbl). The characteristics of the brent sands reservoir from (sorbie et al,1971) located in the UK was used to create five scenarios to make these comparisons. These scenarios each had different producer and injector in the well and therefore had different results.

The CMG simulation software has been used to run a field model with the use of EOR to optimize the overall production. Normal injection, water injection and three cases of polymer injection have been investigated based on recovery factor, cumulative oil produced(bbl) and cumulative water produced (bbl). The result of this study concludes that the three polymer injections with polymer percentage of 5%, 15% and 23% provides the best oil recovery factor of 68%, 72% and 73.98. respectively and also a higeher cumulative oil produced (bbl) compared to water injection and normal injection.

Keywords: *Polymer injection, oil recovery factor, cumulative oil recovery(bbl), CMG star simulation software.*

Özet

Bir Petrol Rezervuarında Polimer Enjeksiyonunun Etkisinin Analizi, Brent Alanı, Birleşik Krallık

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MSc., Petrol ve Doğal Gaz Mühendisliği Bölümü

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Birincil geri kazanım yöntemleri, büyük miktarda hidrokarbonu geri kazanılmamış halde bırakır.Polimer gibi ikincil ve üçüncül geri kazanım yöntemleri, hidrokarbonların ek bir yüzdesini geri kazanmak için kullanılır. Polimer enjeksiyonu, birkaç yıldır uygulanan kimyasal bir enjeksiyon yöntemidir.Polimer enjeksiyonu, su viskozitesini arttırmak (yani, enjekte edilen faz hareketliliğini azaltır) için kullanılır.

Bu araştırma, bir yağ rezervuarında, özellikle ağır yağda polimer enjeksiyonunun etkisinin analizinde yer alan mekanizmalara odaklanmayı amaçlamaktadır.kullanarak simülasyonlar gerçekleştirerek cmg star.En iyi geri kazanım faktörüne ve kümülatif yağ geri kazanımına (bbl) sahip olanı bulmak için çeşitli senaryolardan elde edilen sonuçları karşılaştırın.Kuzey denizinde bulunan sorbie ve ark., 1971'den Brent kum rezervuarının özellikleri, bu karşılaştırmaları yapmak için beş senaryo oluşturmak için kullanılmıştır.Bu senaryoların her birinin kuyularda farklı üretici ve enjektör vardı ve bu nedenle farklı sonuçlar elde edildi.

CMG simülasyon yazılımı, genel üretimi optimize etmek için EOR kullanımıyla bir saha modeli çalıştırmak için kullanılmıştır. Normal enjeksiyon, su enjeksiyonu ve üç polimer enjeksiyon vakası, geri kazanım faktörü, üretilen kümülatif yağ (varil) ve üretilen kümülatif su (bbl) bazında incelenmiştir. Bu çalışmanın sonucu, %5, %15 ve %23 polimer yüzdesine sahip üç polimer enjeksiyonunun %68, %72 ve 73.98'lik en iyi yağ geri kazanım faktörünü sağladığı sonucuna varmıştır. su enjeksiyonu ve normal enjeksiyon ile karşılaştırıldığında sırasıyla daha yüksek bir kümülatif yağ üretilir (varil).

Anahtar Kelimeler: *Polimer enjeksiyonu, yağ geri kazanım faktörü, kümülatif yağ geri kazanımı(bbl),CMG yıldız simülasyon yazılımı.*

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List of Abbreviations

Ad: Area of Displacement

CMG: Computer Modelling Group

Ea: Areal Sweep Efficiency

Ed: Microscopic Displacement Efficiency

ER: Overall Recovery

EV: Vertical or Invasion Efficiency

EOR: Enhanced Oil Recovery

EP: Pattern Efficiency

EUR: Estimated Ultimate Recovery

GIGO: Garbage in, Garbage Out

OOIP: Original Oil in Place

Sor: Oil Saturation

Soi: Initial Oil Saturation

Winj: Water Injection

Np: Cumulative oil production

P: Pressure

Q, q: Flow rate

CHAPTER I
Introductıon

Background

A significant portion of hydrocarbons cannot be recovered using primary recovery techniques. An additional portion of the reservoir's hydrocarbons are recovered using secondary recovery techniques. After primary production, widespread secondary recovery techniques like water injection and immiscible gas injection have been used on many reservoirs throughout the world to recover an additional amount of oil. Enhanced oil recovery (EOR) techniques are required after a range of production phases to boost and maximize the recovery from an oil reservoir.

Polymer injection is a chemical injection procedure and has been used for many years. Polymer flooding is often used to enhance the viscosity of water in order to improve the oil sweep efficiency inside the reservoir rock and also to reduce the injection phase mobility.

The brent field was discovered by Shell-Esso in 1971, it was the first discovery in the Northern North Sea and is one of the largest hydrocarbon accumulations in the United Kingdom. It is located in about 140m (470 feet) of water approximately 160 km (100 miles) northeast of the Shetland Islands. The field has two major separate accumulations: one in the Middle Jurassic (Brent reservoir) and the other in the Lower Jurassic (Statfjord reservoir). Accordingly to (Sheng, 2015). As an example in figure 1.1 depicts a polymer injection process with one injector well and one producer well, suggesting a normal injection phase of this EOR process. To start, flush a low salinity brine. Second, a slug of polymer solution is injected. Finally, there is traditional water injection in which shows the polymer injection process.

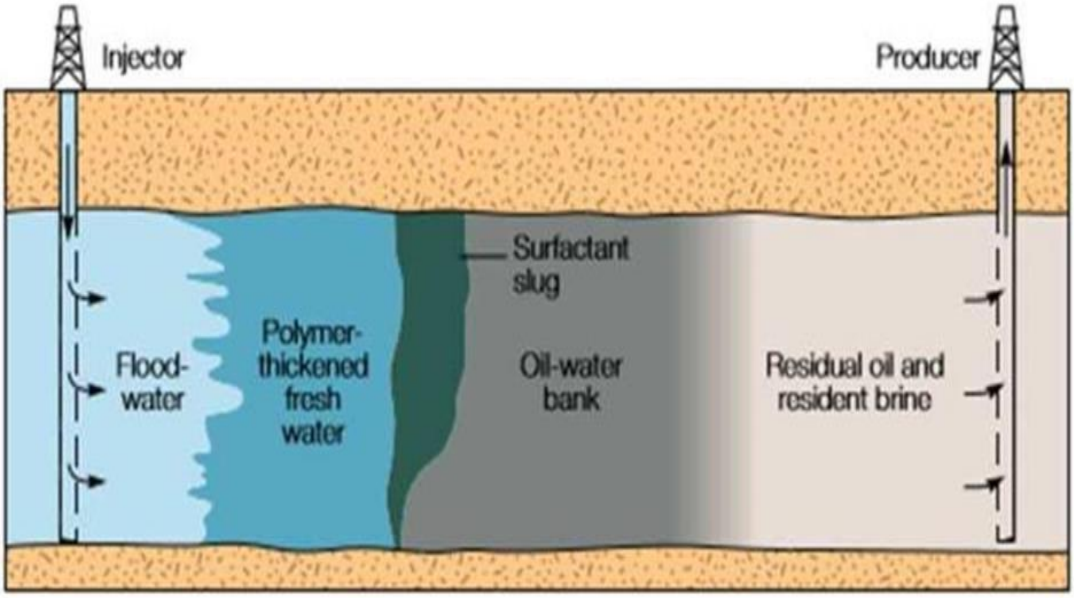

Figure 1.1. *Polymer Injection Process (Sheng, 2015)*

Earlier research on the effects of polymer injection on reservoir geomechanics has been performed. For example, Khodaverdian (2009) offers a geomechanical perspective on the commonly faced issue of polymer flooding in unconsolidated formations comprising viscous oil and Li (2015) examined the impact of fracturing during polymer injection. Due to impurities and solids in the injection fluid that clog the sand face over this duration, together with high in-situ oil viscosity and low polymer mobility, undesirable rock shear failure or fracture propagation during polymer flooding (Teklu, 2012) could arise.

The major study goal of this research is to comprehend the impacts of polymer injection in a heavy oil reservoir using the CMG simulator as a base for analysis. The findings of this study shed light on the Oil recovery factor, Cumulative oil recovery(bbl) and the cumulative water produced that might be achieved during polymer injection which will be determined by the various polymer percentages and also finding the polymer percentage with the best recovery factor and cumulative oil recovery(bbl).

Objectives of the Study

The following are the main goals of this study:

- Analyzation of the recovery factor of polymer injection in a heavy oil reservoir.
- Conduction of intensive simulation work under the CMG stars making use of normal injection, water injection and polymer injection scenarios for the sole purpose of enhancing recovery method.
- Comparing the results of the recovery factor, cumulative oil recovery and cumulative water produced in order to select the best scenario among them.

Research Goal

Analyzing the impacts of polymer injection in a heavy oil reservoir using the cmg simulation software and the stars builder to forecast changes in the reservoir rock.

Aim of the Study

Build a reservoir simulation model with the rock properties,

- Perform sensitivity analysis of the normal injection, water injection and various percentages of polymer injection to determine the one with the best result.
- analyze the five various scenarios to determine the one with the best recovery factor sctr(%), cumulative oil recovery(bbl) and also the cumulative water produced(bbl).
- comparison of the three polymer case scenarios to determine the one with the best recovery and cost efficient.

Limitation of the Research

One limitation to this study is that actual reservoir field data of this topic are really hard to obtain because companies are strict in releasing data to individuals. Another limitation is that only a numerical simulator will be used (without being accompanied by a laboratory study). Since reservoir simulation models have some limitations to how accurately they capture the interaction of polymer injection, there will be a limit to the accuracy of the results obtained from this simulation.

Structure of the Thesis

The first chapter is an introduction to polymer and also the reservoir simulation, its relation to polymer injection, how that relationship will be used in this thesis and the aim and objective of this thesis. The second chapter will present earlier research concerning the use of polymer injection used in reservoir simulation and the data collection from a real field used to develop a range of realistic values for the creation of the model. The subject of Chapter 3 will be the methodology of the research while the fourth chapter will provide information on the results of the research and the degree of accuracy of these results. Chapter five will focus on the conclusions of the research and recommendations of the research.

CHAPTER II

Literature Review

Polymer Injection

The primary objective of polymer injection in the reservoir is mainly to help increase significantly the amount of sweep efficiency whilst also lessen water mobility, which decreases viscous fingering and enhances the water injection profile by cutting down cross flow between vertical and heterogeneous layers, enhancing water permeability, which in turn making subsequent water flooding more efficient. Due to disproportionate permeability reduction caused by the polymer properties and molecules adhering to its rock surface, the known relative permeability of water (krw) is reduced higher than relative permeability of oil.

The polymer injection process is influenced by several factors, including temperature of reservoir, clay content and concentration, reservoir formation water salinity. Many reservoir aspects need to be taken while developing a polymer injection process, according to (Wang, 2008) such as reservoir heterogeneity, stratigraphy, well pattern, well distances, remaining oil distribution and reservoir lithology.

Polymer injection constraints and limitations are as a result of polymer degradation caused by higher temperature, lack of tolerance to greater salinity and inadequate injection rates due to polymer viscosity.

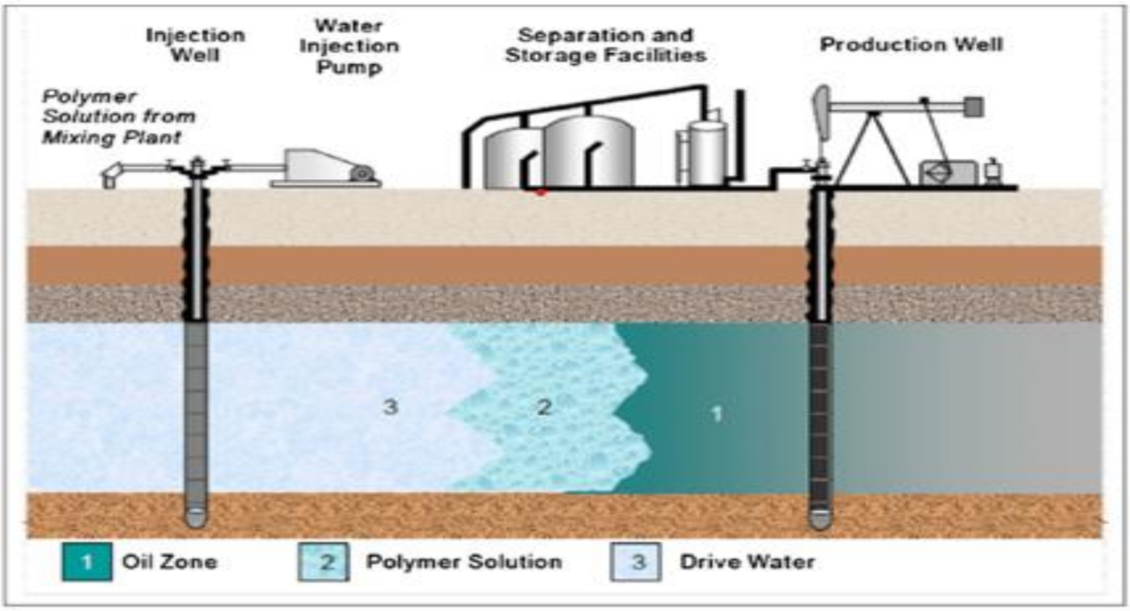

Figure 2.1. *Polymer Injection Workflow (El-hoshoudy, 2016)*

Types of Polymer

Polymer known to be utilized as enhanced oil recovery method in heterogeneous reservoirs to raise the oil recovery factor. The heterogeneity of polymer is attributed with much better mobility ratio of oil and also relatively of water, resulting to a lower sweep efficiency, as well as the previously described viscous fingering and permeability heterogeneity. Polymer injection is a remedy to these sort challenges since it lowers mobility ratio with infusing polymer into water injection, in turn enhancing the viscosity of the water by several degrees. Polymer injection can enhance flow efficiency which also helps in oil recovery. Polymer injection has no effect on the reservoir's residual oil saturation. It simply enhances sweep efficiency by the production of more mobile oil, which conventional water injection cannot produce. In other words, the purpose of polymer injection is to increase rather than augment oil recovery.

Polymer is a viable alternative for Enhanced oil recovery when the reservoir has a huge mobility ratio and a higher rate of heterogeneity for commercial purposes.

In the oil sector, polymer injection predominantly uses two types of polymer. The first is a man-made polymer called polyacrylamide, specifically its hydrolyzed form known as HPAM which is known as xanthan or referred as biopolymer. Since xanthan and HPAM both indicates several additional involvements in other sectors, there are the two known polymer types used in the petroleum sector, and as a result, there is sufficient knowledge available regarding them.

Polyacrylamide or HPAM

Polyacrylamide or HPAM hydrolyzed structure, is commonly employed more than the known and frequently used xanthan. It is made up of material straight chained acrylamide monomers, several of which are hydrolyzed, Along with its versatile chain structure, the HPAM molecule is known as a random coil.HPAM has a diameter of around 0.5 μm which has a molecular and property mass of roughly 5 million a.m.u and the amount of HPAM is a vital feature as it influences the known polymer's properties such as ,hardness and salinity, adsorption of properties and particules,heat stability of the well, shear stability of properties, and also water solubility of the reservoir. HPAM's functional design makes it much more reactive to the reservoir's environmental factors. As a result, before it is employed on a broad scale, it is necessary to gain a thorough understanding of HMAP and conduct several experimental studies.

Biopolymer or Xanthan Polymer

Biopolymer or the xanthan that is made up of the bacterium camperstris and Xanthomonas. It has a cellulose-like system composed up of a structure of glucose monomers joined by glycosides. In contrast to xanthan and HPAM has been conceptualized as a strict pole form.

The idea that xanthan is a helical structure, the side groups compact along the helix to create this shape. to produce a rigid, shaft like macromolecular was put out by (Moorhouse, 1977). The length of the xanthan size and volume is calculated using several studies (Whitcombe, 1978) to be between 0.6 and 1.5µm.

The molecular mass concentration of xanthan is about 2 million a.m.u. Xanthan has a strict pole form look alike structure that makes it low sensitive to PH scale, temperature and pressure and relatively strong salinity and hardness than other materials.

Polymer Degradation

Any practice that causes the molecular structure of a polymer to disintegrate during polymer flooding is known to as polymer degradation. mechanical polymer degradation, Chemical polymer degradation and biological polymer degradation are t he three basic kinds of polymer degradation.

Chemical Process

Chemical process that disintegrates the chemical makeup of a polymer over time is referred to as chemical degradation. Chemical conditions such as hydrolysis and oxidation, temperature and pressure, salinity and hardness of the reservoir and PH scale all have an impact on how long a polymer will last. Because the temperature at which polymers thermally crack is quite high and typical reservoir temperatures are often below a specific thermal crack temperature, the majority of polymers are thermally stable at reservoir temperatures. Polymers are resilient at extremely low and high PH, particularly at high temperatures and pressure, according to experiments.

The stability of the polymer is influenced by hydrolysis over the long term. The hydrolyzed extent in HPAM will gradually be depleted by hydrolysis, which will cause a drop in viscosity and an enhancement in hardness sensitivity. Because xanthan's firm backbone is inflexible, the effect of hydrolysis on xanthan is significantly more severe. The most important chemical reaction that compromises the stability of polymers is oxidation; as a result, antioxidants and oxygen scavengers are applied to the polymer to stop oxidation processes that arise from the presence of oxygen.

Mechanical Degradation

Indicates that the amount of fluid flowing is significant that the extreme stress causes polymer molecules to break down. A permanent drop in viscosity and resistance factor will result from this mechanical deterioration. As far as mechanical degradation is concerned, it has understood and shown that the biopolymer xanthan is quite stable.

The stiff molecular structure of it is the source. As a result of its flexible molecular shape, PAM is nevertheless thought to be extremely susceptible to shear and blatant degradation.

Biological Degradation

Microorganisms breaking away the polymer's molecular structure; generally, degradation is caused by bacteria in the brine. If the reservoir is cold enough, biological breakdown can occur both there and on the surface prior to polymer injection.

Polymers are frequently treated with biocides to prevent microbial deterioration. A few aspects that influence biological degradation include the kind of the well brine salinity, the brine bacteria, chemicals located within the reservoir and the enormous reservoir temperature and pressure.

Water Injection

Secondary method should be used due to the pressure reduction brought on by the primary recovery, the secondary method should be utilized to preserve pressure and sweep out additional oil. Water ınjectıon is a common standard procedure in many reservoir forms. In the late 1800s, water ınjectıon was regarded as a secondary recovery method in the petroleum sector.

The total effective efficiency which is also total recovery factor of water injection, secondary recovery techniques, or tertiary recovery techniques can be observed by the formula below.

$$RF = \frac{N_p}{N} = (ED)(EA)(EV) \qquad (2.1)$$

RF = known as the recovery factor

N = known as the initial oil in place

NP = known as the cumulative oil produced in the reservoir

ED = known as the efficiency displacement

EA = known as the efficiency areal sweep

EV = known as the efficiency vertical sweep

The space that was covered by the propelling fluid is measured by the areal sweep efficiency, which is the proportion of oil displacement amount to the infused pore amount. Fluid mobility of the area, areal reservoir heterogeneity, sorts of patterns, and total fluid amount infused are the primary variables that impact the efficiency of the areal sweep. The primary variables impacting Ev which are widely regarded as vertical heterogeneity, volume of gravity segregation, the amount of fluid mobility, and injected volume involved. The vertical sweep efficiency is defined as the percentage of the vertical portion within the target zone that is affected by the infused fluids.

Porosity

The unfilled area in a rock's total volume that is not covered by particles or elements is known as porosity. Because the whole fluids are completely filled in the pore space, porosity is an incompressible characteristic that directly correlates with the volume of all the fluids in the reservoir.

The hydrocarbon reservoirs have two different forms of porosity: efficient porosity (φeff) and efficient porosity (φineff).

the total porosity is the amount of connected pores which facilitate fluid flow, whereas efficient porosity is volume amount of unconnected pores which restrict fluid flow through the pores they are occupied. The total porosity is known as absolute porosity.

$$\emptyset abs = \emptyset eff + \emptyset ineff$$

$\emptyset$abs is often referred to as absolute porosity, $\emptyset$eff is widely termed to as effective porosity, and $\emptyset$ineff is typically called to as ineffective porosity.

Fluid Saturation

The fluid fraction located within the pore volume can be used to determine fluid saturation.

The formula for fluid saturation.

$$S_i = \frac{VI}{V_P} \quad i = w, o, g \qquad (2.2)$$

where Si is phase i fluid saturation, while Phase I is fluid volume, Vi is equal to phase I pore volume Vp.

The total fluids saturation in the hydrocarbon reservoirs is always equals to 1

$$Sw + So + Sg = 1 \qquad (2.3)$$

Residual Oil Saturation

Remnant trapped oil that is immobile after water injection is known as residual oil saturation, and it comes as a result of interstitial fluid forces acting in the pore space. Many models have been put out to explains why oil is trapped after the water injection. The two primary method or model are the snap-off model and pore doublet model.

Its observed and known that doublet model process has the tendency to therefore move quickly due to the small opening that is caused by the capillary difference trapping and the non-wetting phase when there are two pathways or channels for the flow.

Permeability

Permeability is a critical feature in hydrocarbon reservoirs. It assesses the formation's ability to transport fluids. The fluid flow path and mobility in the structure of the pores space are controlled by the rock permeability, k. In 1856, Henry Darcy devised a mathematical strategy and pattern to characterize the transport and circulation of fluids through porous media. For an immiscible fluid flowing horizontally within a cross section area A and test section of length L.

$$q = -\frac{k\ A\ dp}{\mu\ DL} \qquad (2.4)$$

q= means and can be measure as the flow rate [cm3/sec]

A= means and can be measured as the cross-section area, [cm2]

k= shows and can be measured as the Permeability, [Darcy]

μ= shows and can be measured as the fluid viscosity, [cp]

dp/DL= shows and can be measured as pressure per unit length, [atm/cm

Software Description

The software is Computer Modelling Group 2015, StarsTM user guide is a three phase constituent thermal and steam multiplicative simulator. The grid technology system is structured to be either cylindrical, variable depth/thickness or Cartesian, there are two configuration options. Two or three dimensional arrangements utilizing some of the grid systems outlined.

The process of modeling polymers, gels, fines, emulsions, and foam, the essence of dispersed elements is to regulate dispersions with one stage to the next which provides a unified perspective. Furthermore, it manages fully implicit wells reasonably and comparatively better. The column variables and bottom hole pressure for the completed blocks of the wells are entirely implicitly rectified. There is a broad list of limitations that can be entered, including GOR, bottom hole pressure, wellhead pressure and other parameters Aquifers are represented by incorporating boundary cells that are only made up of water or by using a sub analytical and aquifer model.

In accordance with the StarsTM user guide of the Computer Modelling Group 2015, It addresses these issues by minimizing the wellbore flow, also by resolving the consequent wellbore/reservoir flow problem at the same time.

At the conclusion of each time step, wellbore flow patterns are explicitly adjusted using the proper multiphase flow correlations. A geomechanical model with three submodules is offered to address some of the issues raised above. Modular and explicit coupling is used to connect the geomechanical model and simulator. This lowers the cost of computing while improving the model's flexibility and mobility.

CHAPTER III
Methodology

This chapter is focused on the methods and procedures for this thesis. It details the steps taken to model and solve the thesis problem such as parameter selection and constraints, programs used and techniques applied to solve the thesis problem.

Case Study of the Brent Field, UK

This work will base its simulation study on a field located in brent field, UK. The Brent field is an oil field located in the East Shetland Basin. This oil field was first discovered in 1971 in the northern part of the North Sea. Using information gotten from literature review and also gathering enough data was key in launching this simulation job successfully.

Using the data which respectively contains five layers of the model and this model has different permeability which will be shown and defined as well.

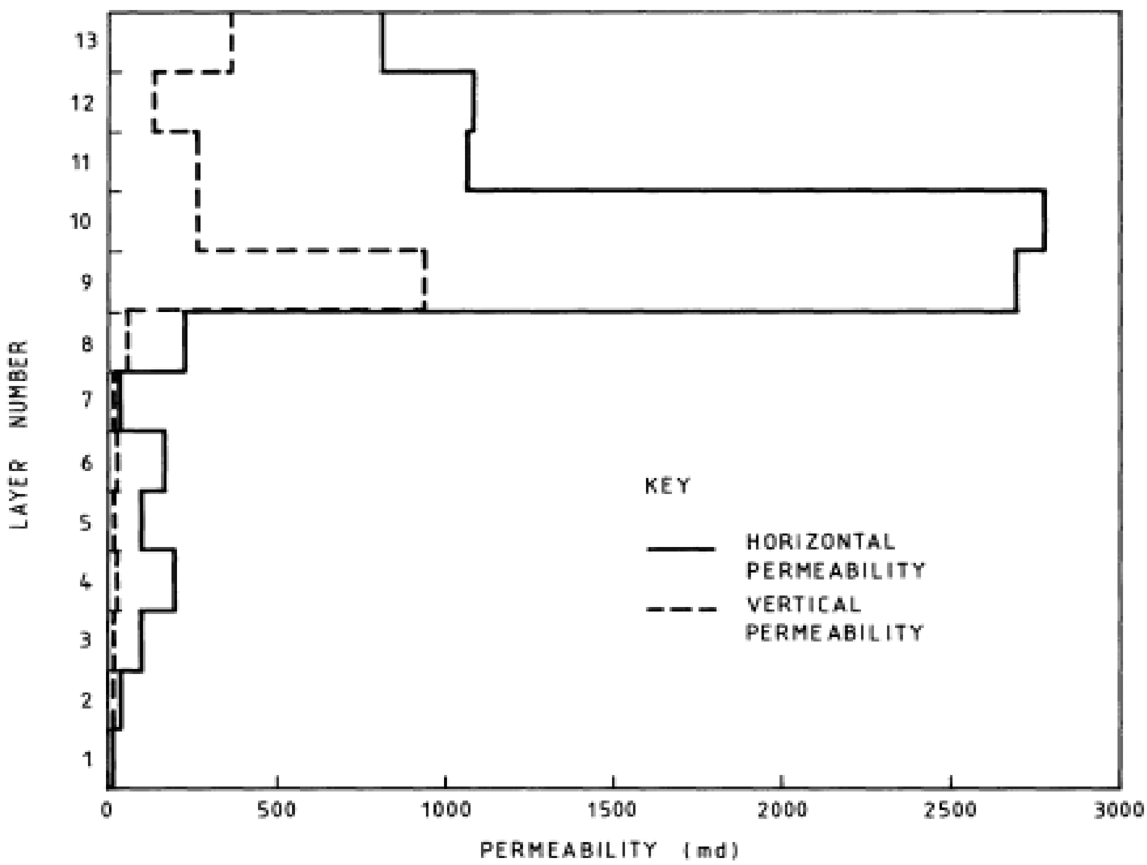

Figure 3.1. *Polymer Injection Process (Donaldson, 1992)*

Initial Properties of the Reservoir, Grid Modelling and Well Pattern

This case study has been modeled using the reservoir simulation tools CMG and stars builder. Five layers with varying permeability's are used to model a stratified reservoir with substantial permeability contrast. Layers 1 and 5 have permeability's of 12 md from the bottom to the top which is shown in the diagram below.

Layer 2 and 4 have permeability of 60 md respectively while layer 3 in the center has permeability of 600 md which shows that its the highest in terms of permability. The average porosity of all layers is set to be 0.2. The average thickness for all layers is set to be 35 ft.

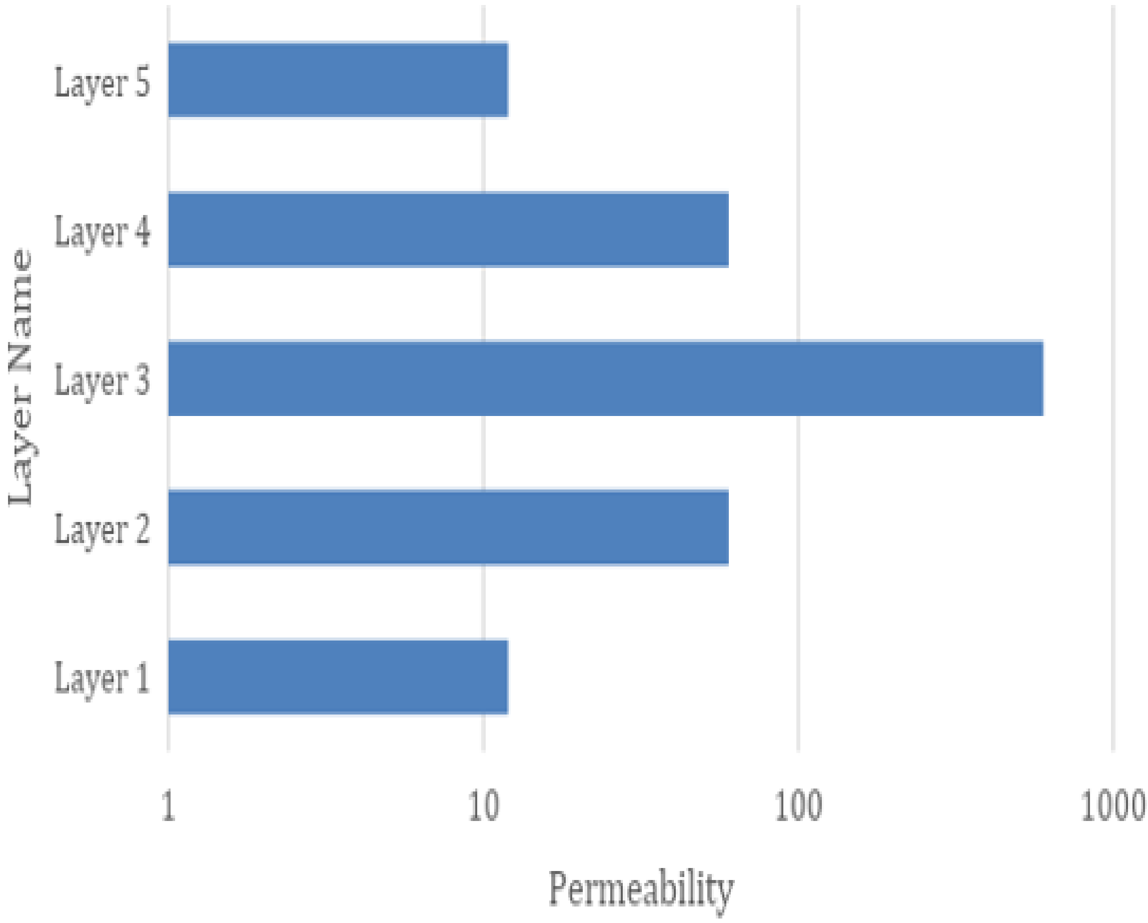

Figure 3.2. *The Reservoir, Grid Modelling and Well Pattern (Daigang, 2018)*

Five spot synthetic reservoir model shows a well-connected naturally fractured reservoir simulated by using a 2d model in the CMG simulating software which the production well is located at the corners on the diagram below. The reservoir properties and the initial conditions have been obtained from highly stratified Brent Sands reservoir from (Sorbie, 1982).

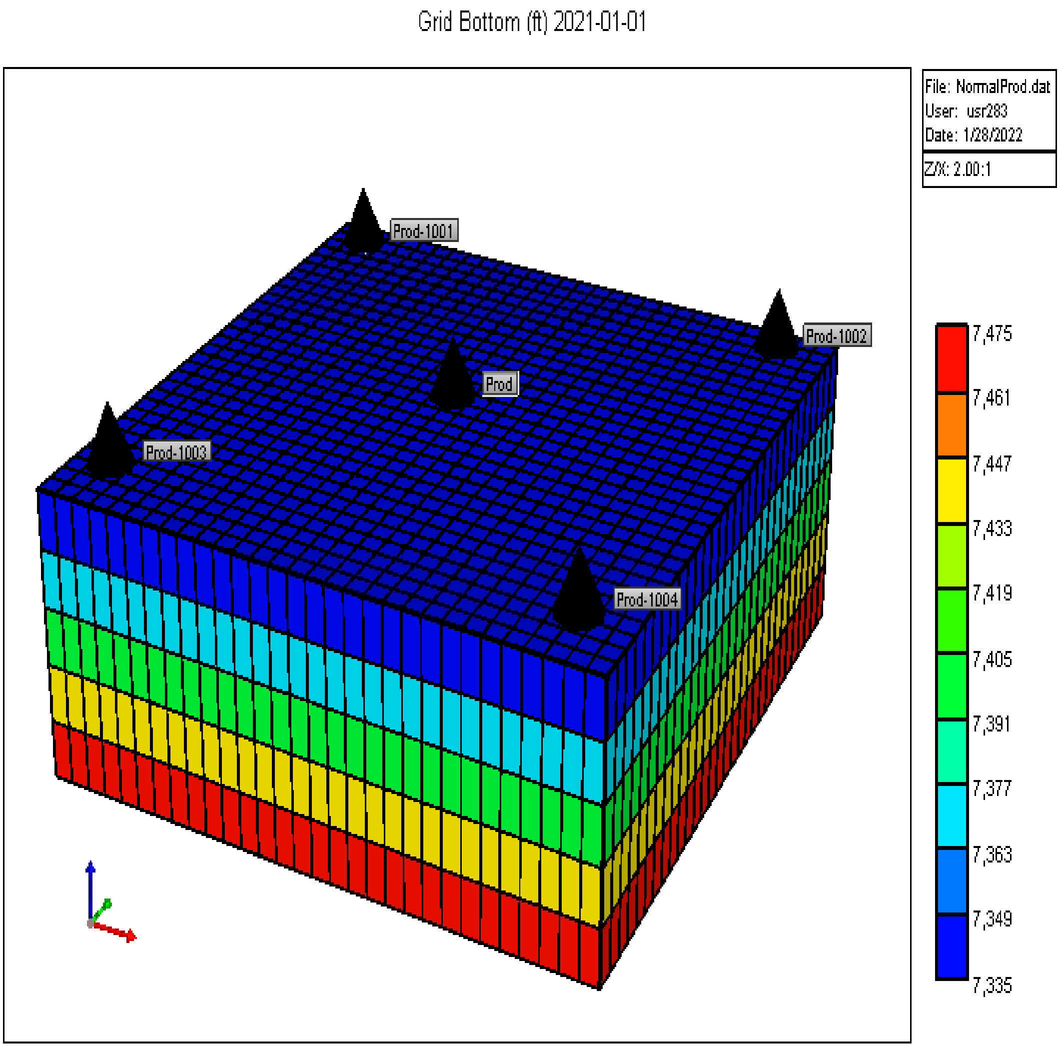

Figure 3.3. *Five Spot Synthetic Reservoir Model (Generated by CMG Builder)*

For this model, a reservoir of 30 blocks were specified for the reservoir block in this model, 30 blocks in the y direction, and 5 blocks in the z direction. The cell size is 30 ft. of length, 30 ft of width and 35 ft. of thickness. The sector area is 450000 ft2 and the volume is 141.75 MMbbl..

Table 3.1.

Reservoir Data From Brent Field Reservoir, UK

Reservoir Model Parameters, Unit	Value
Depth (Top), ft	7300
Length, L ft	900
Width, W ft	900
Height, H ft	175
Number of grids in x, y & z	30, 30, 5
Cell dimensions in x direction, ft	30
Cell dimensions in y direction, ft	30
Cell dimensions in z direction, ft	5
Component Simulated	Oil, water, polymer
Initial Reservoir Pressure, Psi	3700
Initial Reservoir Temperature, ^oF	194
Porosity, fraction	0.2
Oil viscosity, cp	1.046
Water viscosity, cp	0.307
Initial Water Saturation, fraction	0.22
Relative Permeability Curve Type	water wet
Residual water saturation, fraction	0.22
Residual oil saturation, fraction	0.21
Endpoint relative permeability of water	0.3
Endpoint relative permeability of oil	0.9
Relative permeability exponent of water	2
Relative permeability exponent of oil	3
OOIP (MMbbl)	22.11
Gross Formation Volume (MMbbl)	141.75

Simulation Scenarios

In this part five scenarios will be designed with different specifications. Namely no injection scenario, water injection scenario and three polymer case scenarios, all with the sole aim to increase the hydrocarbon recovery of the reservoir. The first scenario to be assessed is the production without injection in a 5 well pattern. Followed by the scenario with fresh water injection still with 5 spots pattern. The third scenario we have the first injection of polymer and on the last one the injection of polymer with higher concentration than the previous.

These scenarios are made with 5 wells configured in a 5 spots pattern. A part from the first scenario which has 5 production wells, all other scenarios have 4 production wells at the corners and 1 injection well in the middle.

Normal injection Scenario

This scenario is made for normal production also called primary recovery. It is made of five vertical wells configured with the same production parameters. This scenario has been performed on a time frame of seven years. The figure below shows the top view of the created model and wellbore configuration.

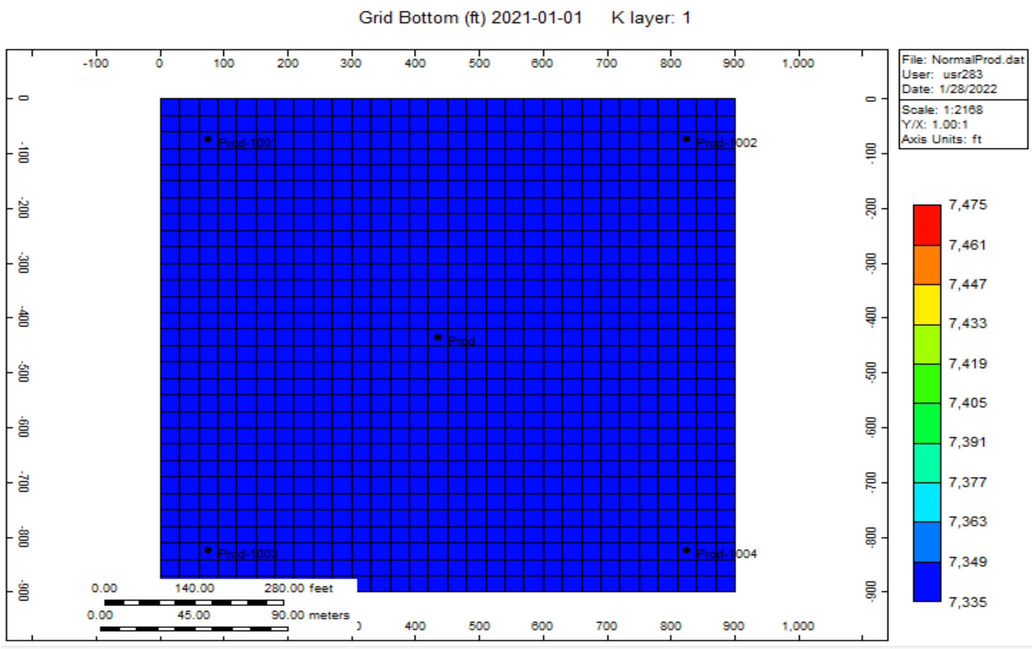

Figure 3.4. *Shows the Top View of the Created Model and Wellbore Configuration of Normal Injection Scenario (Generated by CMG Builder)*

Water Injection Scenario

Water injection is one of the most useful techniques for enhancing the production of oil from petroleum reservoirs. This is not only because of the low cost of water but also because of the characteristics of water which help sweep the trapped oil efficiently. In this particular scenario, the main aim is to investigate and analyse the percentage of oil recovered through water injection and finally comparing it with other scenarios.

This scenario the production is enhanced with water injection aided with four vertical production wells and 1 vertical injection well the production is simulated over seven years.

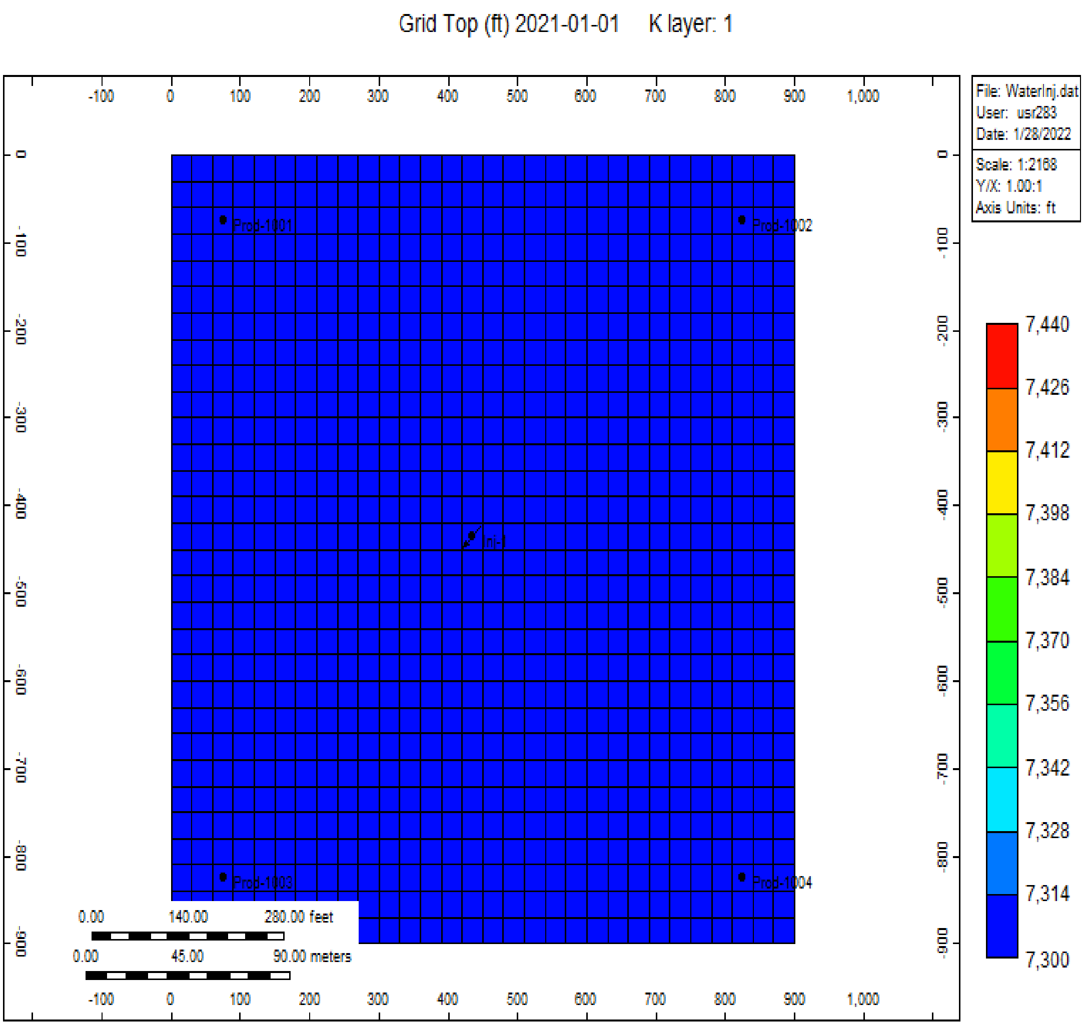

Figure 3.5. *Shows the Top View of the Created Model and Wellbore Configuration of Water Injection Scenario (Generated by CMG Builder)*

Polymer Injection Scenario 1

Polymer injection is a popular enhanced oil recovery method which helps to impact on improvement in sweep efficiency.This is not because of its low cost compared to other enhance oil recovery components but because polymer helps effectively to sweep the trapped oil efficiently. In this first case of polymer scenario, the main aim is to investigate and analyse the percentage of oil recovered and finally comparing it with other scenarios.

In this scenario the production is enhanced with the use of Polymer injection used at a 5% of concentration. Four vertical production wells and one vertical injection well as the previous scenario, production is simulated over seven years.

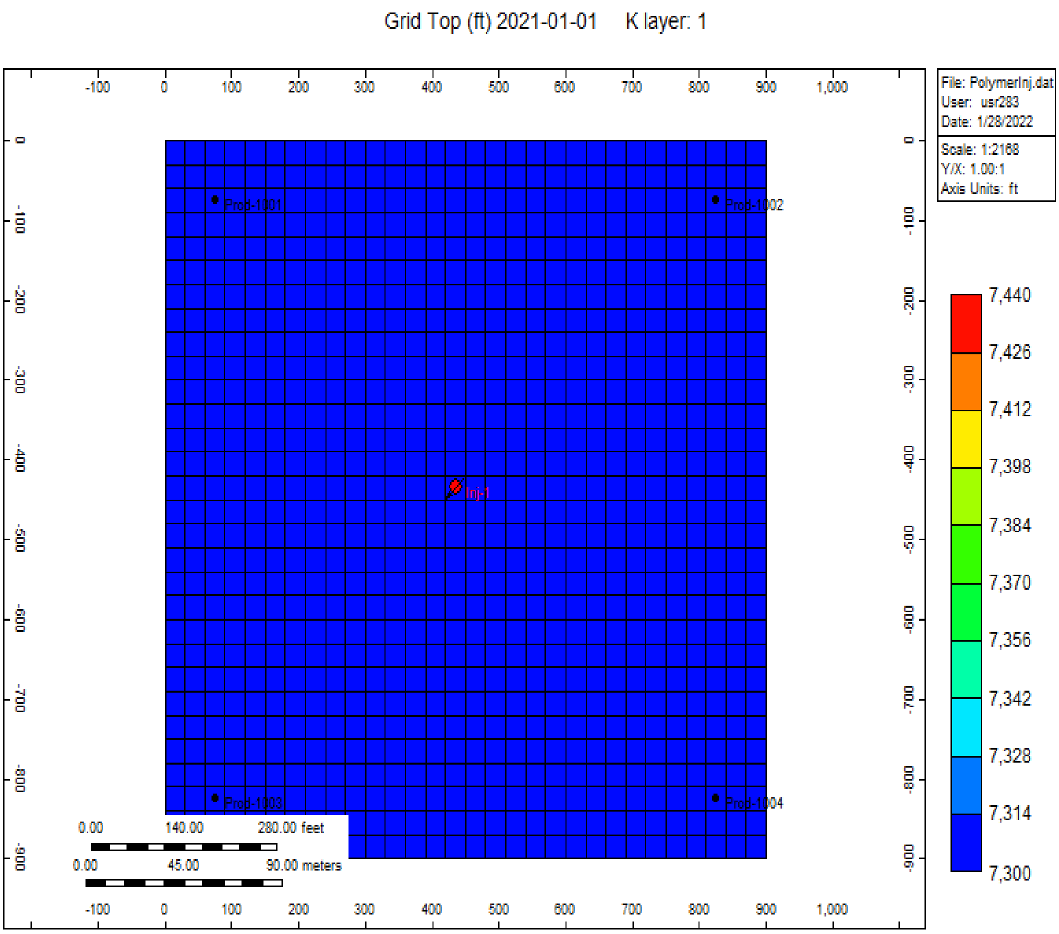

Figure 3.6. *Shows the Top View of the Created Model and Wellbore Configuration of First Polymer Injection Scenario (Generated by CMG Builder)*

Polymer Injection Scenario 2

This is the second case of polymer injection also called tertiary recovery. It is made of five vertical wells configured with the same production parameters. This scenario has been performed on a time frame of 7 years. The figure below shows the top view of the created model and wellbore configuration.

In this scenario the production is enhanced with the use of Polymer injection used at a 15% of concentration.

Four vertical production wells and one vertical injection well same as the previous scenario, production is simulated over seven years.

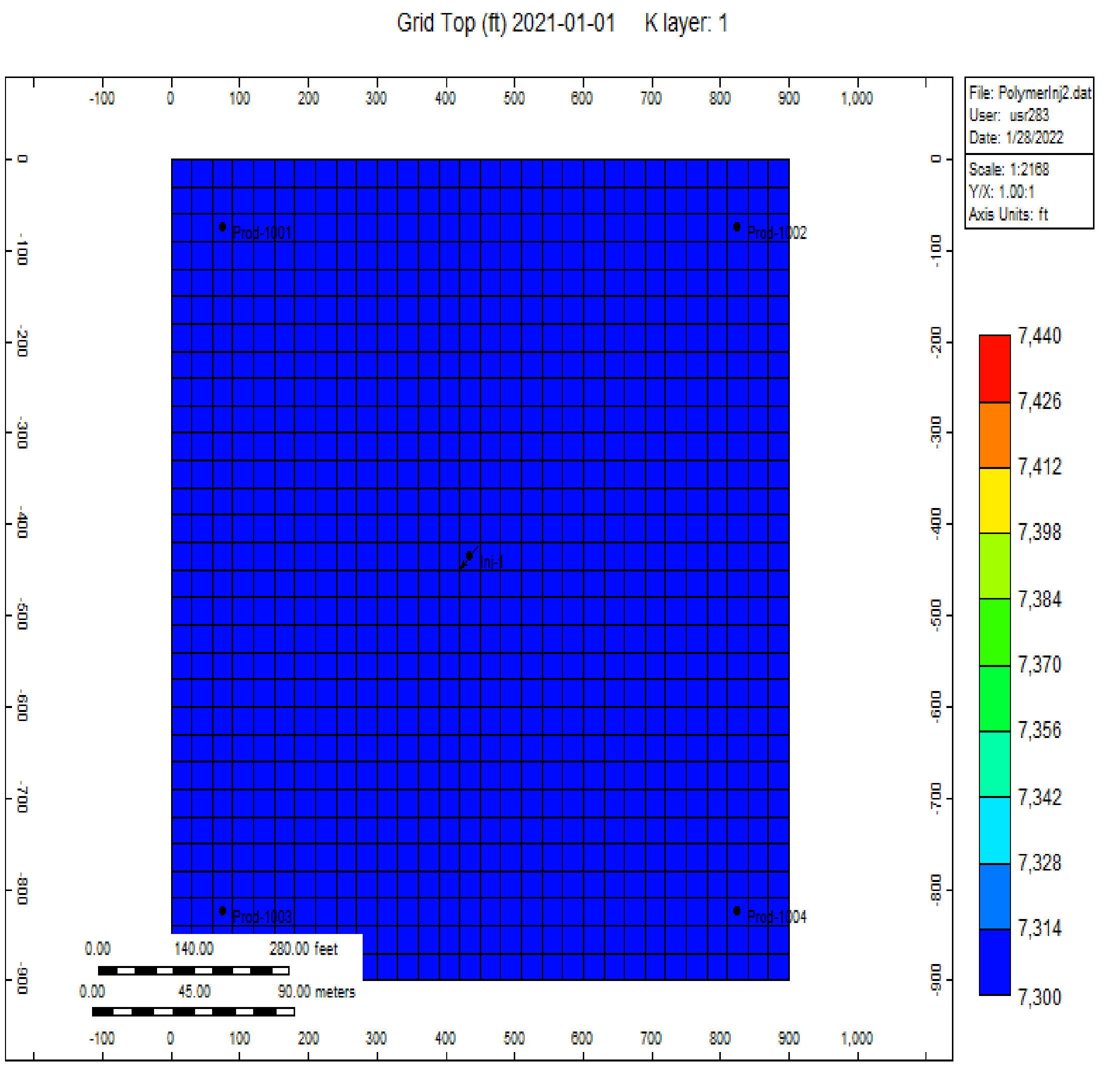

Figure 3.7. *Shows the Top View of the Created Model and Wellbore Configuration of Second Polymer Injection Scenario (Generated by CMG Builder)*

Polymer Injection Scenario 3

The third case of polymer injection also called tertiary recovery. It is made of five vertical wells configured with the same production parameters. This scenario has been performed on a time frame of 7 years. The figure below shows the top view of the created model and wellbore configuration. The main aim of this third case scenario is to investigate and analyse the percentage of oil recovered through higher percentage of polymer injection and finally comparing it with other scenarios.

In this scenario the production is enhanced with the use of Polymer injection used at a 23% of concentration. Four vertical production wells and one vertical injection well same as the previous scenario, production is simulated over seven years.

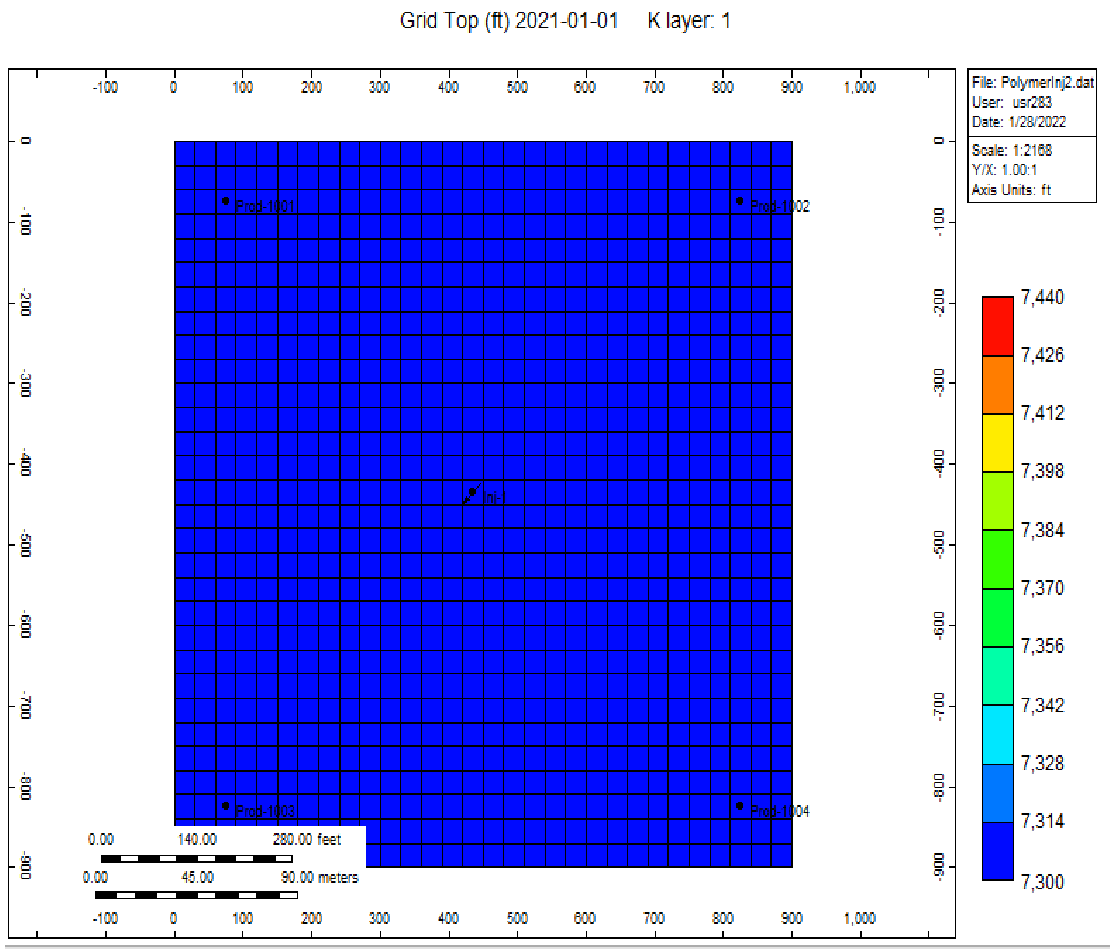

Figure 3.8. *Shows the Top View of the Created Model and Wellbore Configuration of Third Polymer Injection Scenario (cmg,star builder 2015)*

Polymer Values and Properties

In the last two scenarios making use of polymer injection using software available configuration. In the module Builder, there is an option called "Process Wizard" where the user is able to configure the properties and select on which well to use the designed polymer settings. In the tables and graphs below, we have the effects of velocity/shear and salinity on polymer viscosity.

Table 3.2.

The Effect of Velocity/Shear on Polymer Viscosity

Wt%, Polymer	Viscosity, cp	Wt%, Polymer	Viscosity, cp	Wt%, Polymer	Viscosity, cp
0	0.413077	0	0.413077	0	0.413077
0.03	3.5	0.03	3.43	0.03	2.1
0.05	5.2	0.05	5.096	0.05	3.12
0.075	10.8	0.075	10.584	0.075	6.48
Velocity, ft/day	0.0328084	0	0.328084	0	3.28084

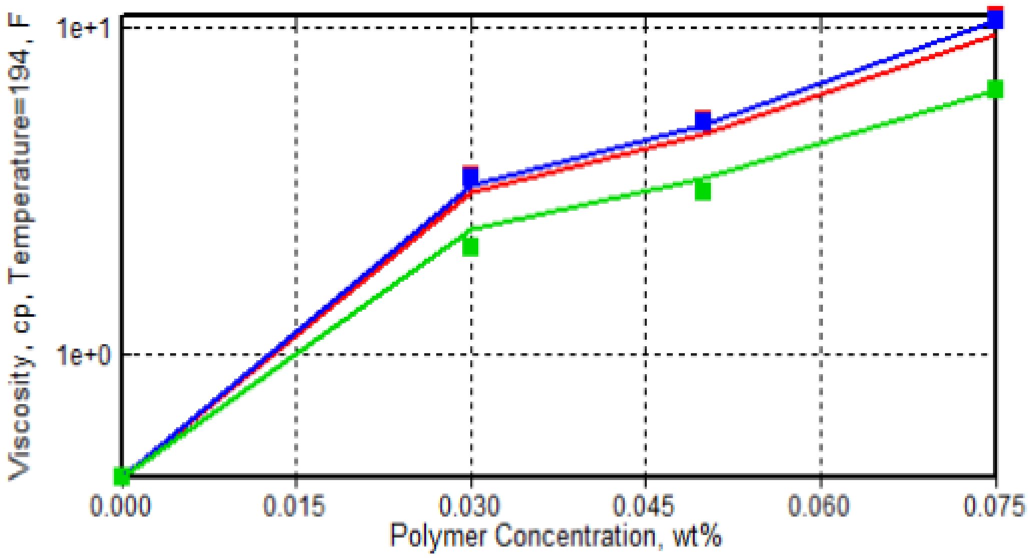

Figure 3.9. *The Effect of Velocity/Shear on Polymer Viscosity (Sheng, 2015)*

Injection and Production Constraints

To enhance the recovery factor, Polymer is injected into reservoirs to increase the sweep efficiency by increasing its viscosity. Polymer is injected at constant rate from the beginning till the end of production. In this work a minimum oil surface production rate has been settle to limit the economic losses.

Table 3.3.

The Effect of Salinity on Polymer Viscosity

Wt% Polymer	Viscosity, cp	Wt% Polymer	Viscosity, cp	Wt% Polymer	Viscosity, cp
0	0.413077	0	0.413077	0	0.413077
0.03	3.5	0.03	1.75191	0.03	0.876908
0.05	5.2	0.05	2.60283	0.05	1.30283
0.075	10.8	0.075	5.40588	0.075	2.70589
Salinity, Ppm	1000	0	5000	0	25000

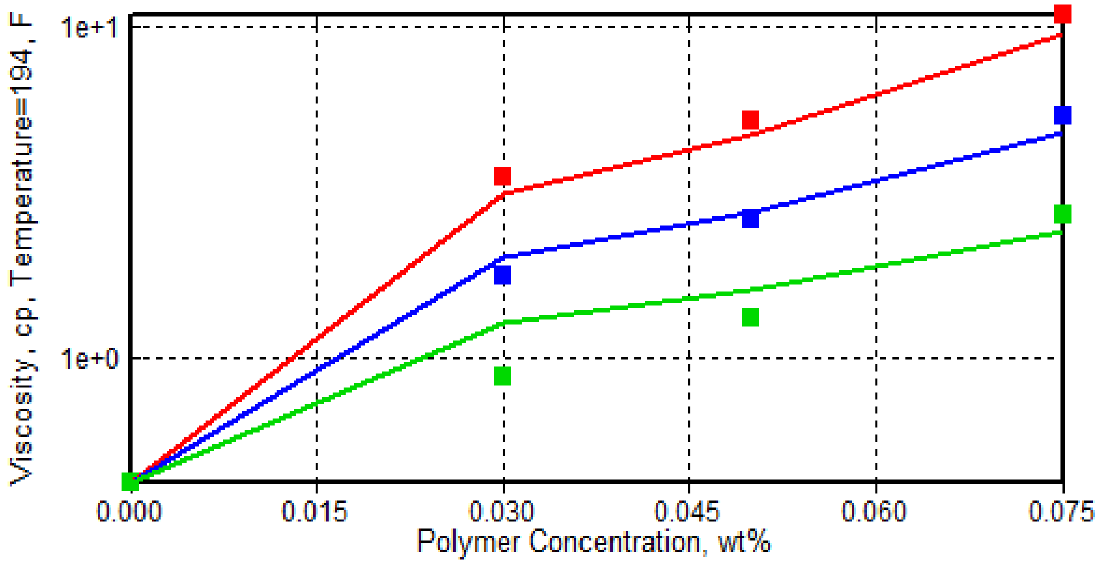

Figure 3.10. *The Effect of Salinity on Polymer Viscosity (Sheng, 2015)*

CHAPTER IV
Results and Discussions

In this chapter, the results from each of the five scenarios stated in chapter three are given and analyzed in detail. Using the same well orientation and configuration, the effect of injection either water or polymer will be compared to the primary recovery production, then the effect of polymer injection upon water flooding will be analyzed and finally the concentration of polymer inside the injection fluid will assessed and the impact on the recovery factor is going to be highlighted.

As explained in chapter three, a model was created and the five scenarios were perform and run under the stars builder in the CMG simulator. After this, the simulation results graphs were gotten by running each of the irf files on the Results Graph on CMG. These results are discussed in this section.

The properties that are extracted from the irf file are the oil recovery factor, cumulative oil production, cumulative water injected and cumulative water produced.

Effect of Water Injection on the Reservoir

In this part the aim is to show the necessity of using an Enhanced Oil Recovery technique. After the evaluation of the hydrocarbon contents which is 22.11e+06 bbl, the production is launched using a scenario were no-injection is made. It is noticed that the maximum amount of oil recoverable through primary extraction is 2.02e+05 bbl leading to a recovery factor of 0.91% which nearly unproductive. Compared with the water injection scenario, the cumulative oil produced is 2.74e+06 bbl and the recovery Factor is 12.4%. from this first analysis it is sure that, EOR is required to produce additional oil from this reservoir.

Even if the amount of recovered oil has been increased due to push exerted by water flooding, the amount of water 10.4e+07 bbl produced is very high and critical. This is due to the mobility ratio of water over oil which is high. Knowing that water has relatively low viscosity, it hasn’t succeeded to sweep a large amount of oil. Illustration of this results is given with the graphs below.

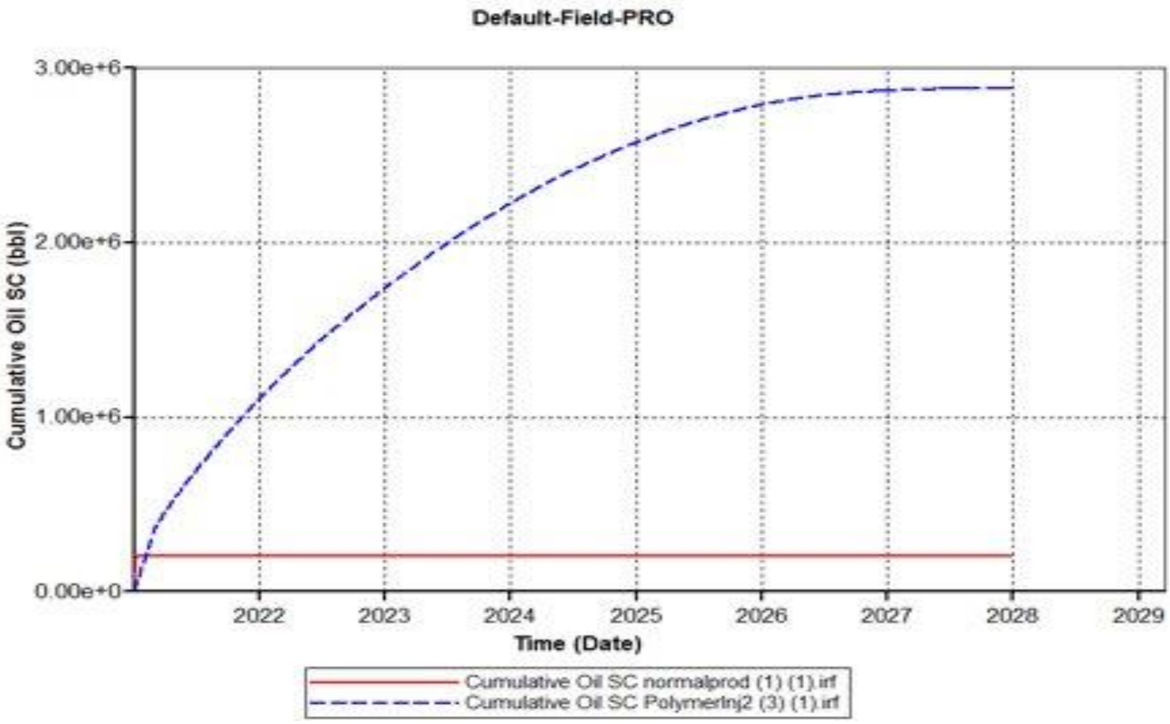

Figure 4.1. *Comparison Between Normal Injection and Water Injection Scenario (Generated from CMG Results Graph)*

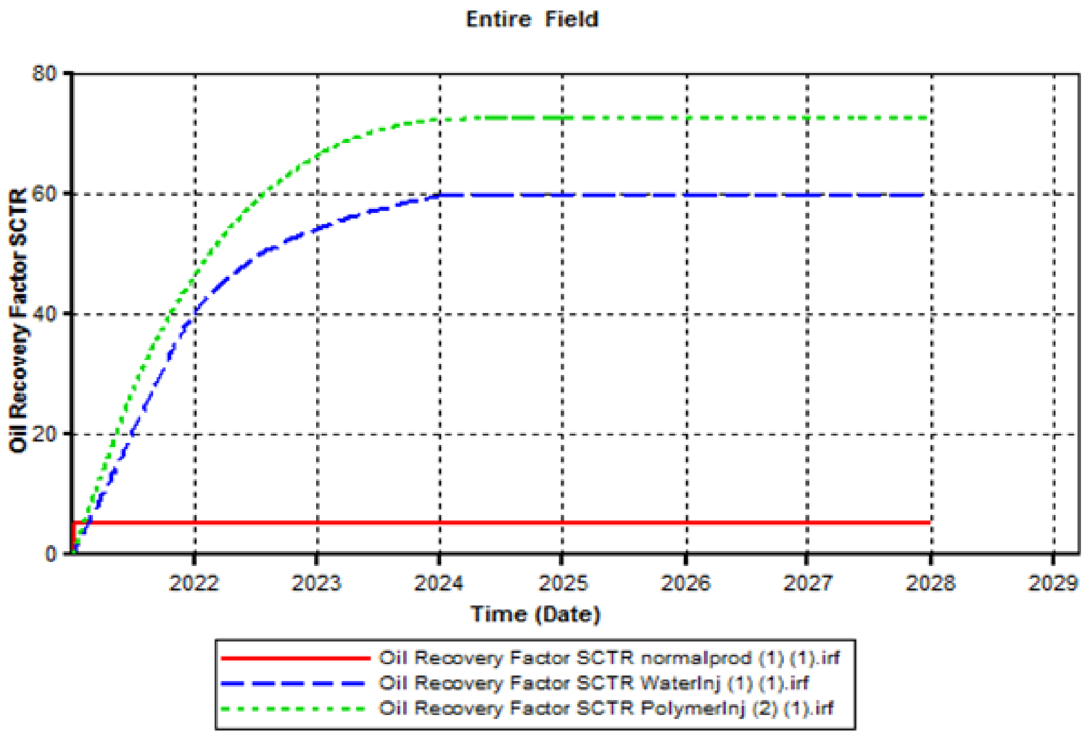

Figure 4.2. *Oil Recovery Factor of Normal Injection, Water and Polymer Injection (Generated from CMG Results Graph)*

Effect of Polymer Injection upon Water Flooding

The obvious way to measure the success of a scenario is through the amount of hydrocarbon produced. Water flood is now compared to polymer injection to understand how each one affects the oil production in terms of Injected and produced fluids either oil or water.

In the previous part the amount of water produced in water flooding was 10.4e+07 bbl which is far greater than the cumulative oil. But using polymer injection there is less water produced and more oil recovered.

The new recovery factor is 12.8% instead of 12.4% in the water flood. The amount of water produced decreased to less than 2% (1.23e+06 bbl) of the one in water injection. This is due to the viscosity increased with polymer additives and reduction of mobility of injected fluid upon oil.

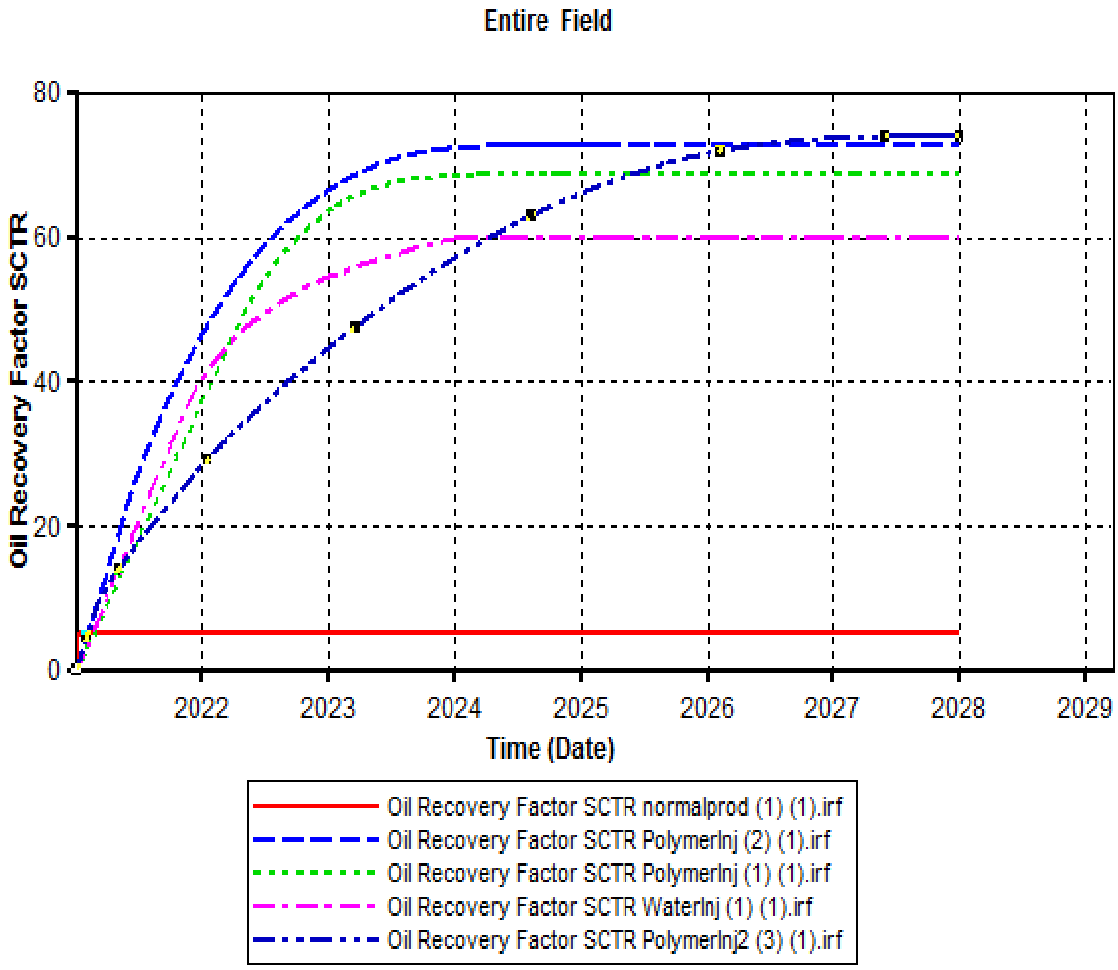

Figure 4.3. *Oil Recovery Factor of all the Case Scenarios (Generated from CMG Results Graphs)*

The water breakthrough is also very important when analyzing efficiency of a scenario, because it is always advisable to have a late breakthrough during flooding techniques. The water breakthrough in water injection happened about 80 days after the injection started while it is after almost 200 days that we recorded it during polymer injection. It is very significant because it tells us how long the injected fluid can take to reach the production wells.

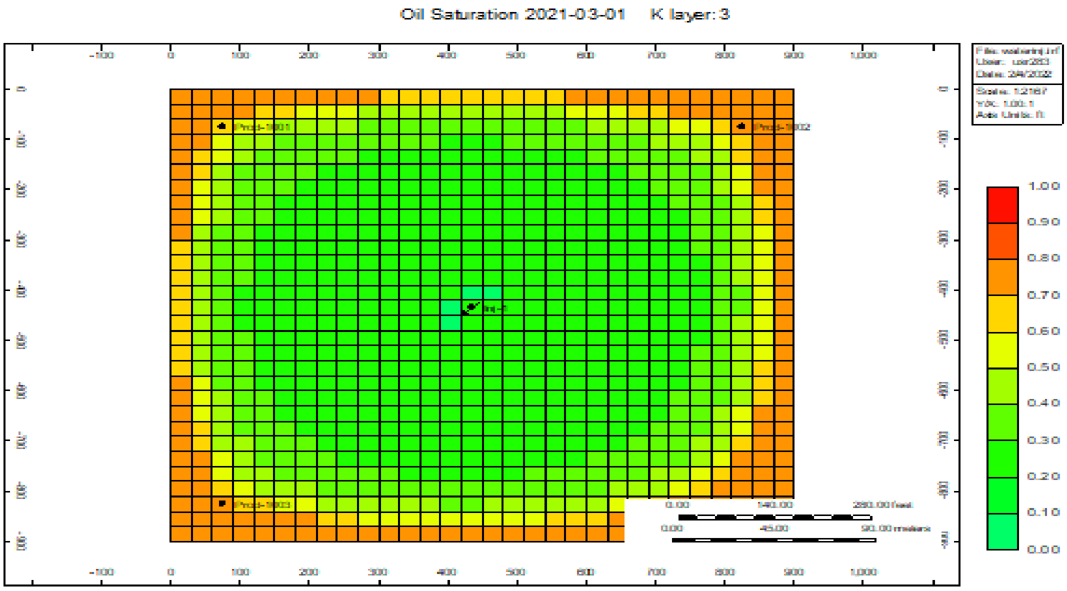

Figure 4.4. *2nd Case Scenario, Reservoir Layer 3 Section During Polymer Injection (Generated from CMG Results Graphs)*

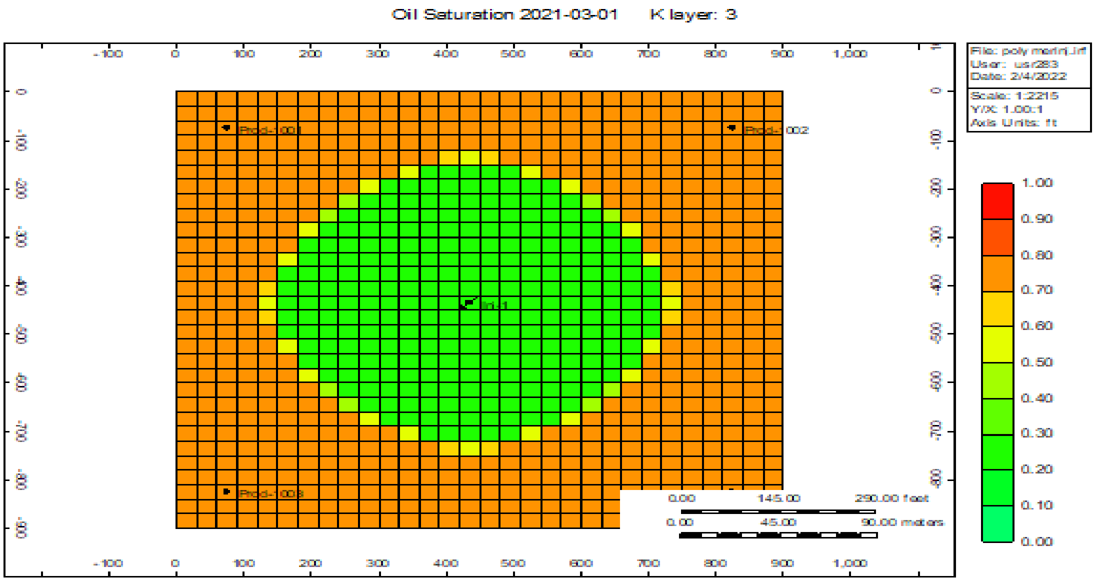

Figure 4.5. *3rd Case Scenario, Reservoir Layer 3 Section During Polymer Injection (Generated from CMG Results Graphs)*

Effects of Different Polymer Concentration on Oil Recovery

Polymer injection shown better results than water injection in terms of water and oil production. There is a need to understand now how polymer concentration affects the production. The 3rd and 4th cases have been compared to control the change in production total. From the figure below, it can be observed that shape of cumulative oil for 1st injection scenario is straighter than the one of 3rd case with higher polymer concentration. This translates the timing of polymer to move from the injection well to the producer wells. It is also seen that the amount of oil produced on the 3rd is slightly greater than the one in the 1st and 2nd polymer injection scenario. The highest cumulative oil produced is 2.88e+06 compared to 2.02e+06 which is the lowest recovered from no injection case scenario.

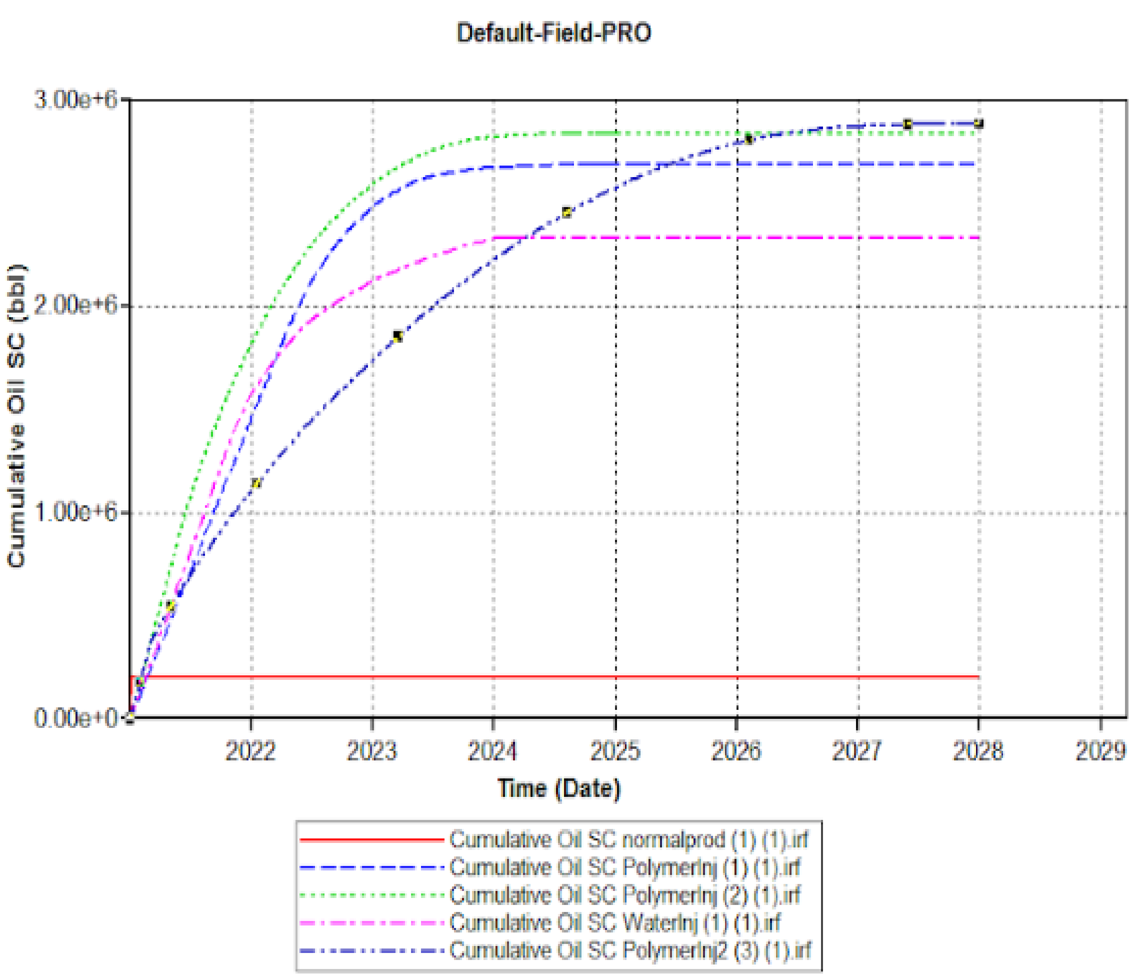

Figure 4.6. *Cumulative Oil Recovery of all the Case Scenarios (Generated from CMG Results Graphs)*

In the 4th scenario, the amount of water produced is 915248 bbl with a difference of 315000 bbl on the one in the 3rd scenario. It means that the more the polymer is injected, the more water cut will be reduced.

The breakthrough occurred about 390 days after the beginning of the injection process.

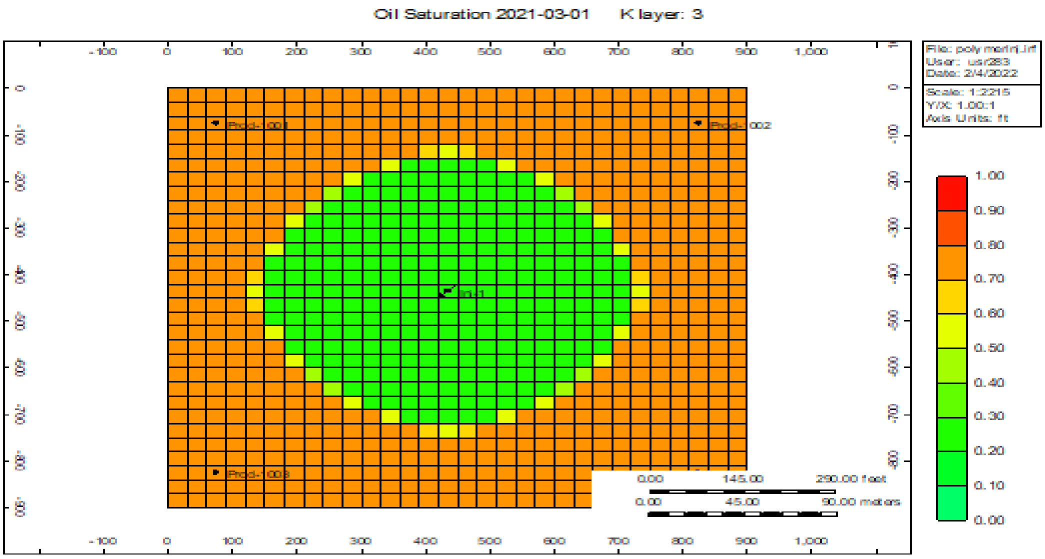

Figure 4.7. *3rd Case Scenario, Reservoir Layer 3 Section During Polymer Injection (Generated form CMG Results Graphs)*

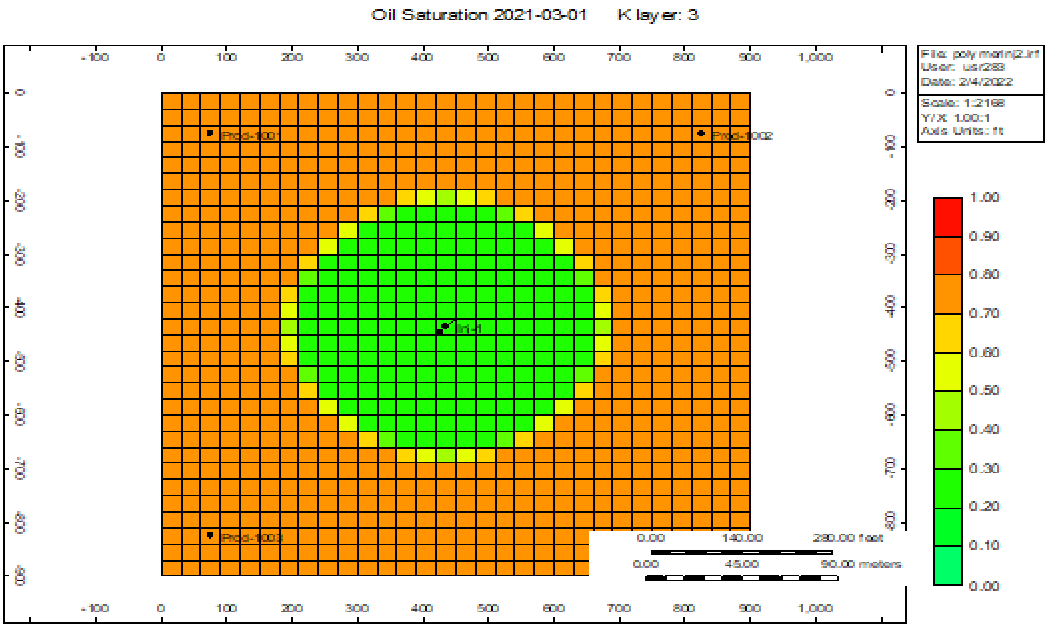

Figure 4.8. *4th Case Scenario, Reservoir Layer 3 Section During Polymer Injection on (Generated form CMG Results Graphs)*

Result Summary of Production Scenarios

This is a summary of all scenarios performed above, it is a set 5 scenarios with specified characteristics and configurations. Here below the table give the main output in terms of numbers we can get from this study. It clearly shows that the 4th scenario is the optimum scenario with less water production and maximum oil produced. This is due to the effect of polymers on water viscosity thus mobility ratio

Table 4.1.

Summary of Stimulation Results

Scenario Number	Description	Cumulative Oil Recovery (bbl)	Recovery Factor (%)	Cumulative Water Produced	Percentage of Polymer
One	Oil production with 5 producers	2.02e+06	5.71%	1.98e+0	none
Two	Oil production with 4 producers and 1 water injector	2.33e+06	9.83%	1.86e+07	none
Three	Oil production with 4 producers and 1 polymer injector	2.68e+06	68.89%	1.64e+06	5%
Four	Oil production with 4 producers and 1 polymer injector	2.83e+06	72.78%	1.22e+06	15%
Five	Oil production with 4 producers and 1 polymer injector	2.88e+06	73.97%	1 .190e+05	23%

Comparison of Results to Previously Published Study

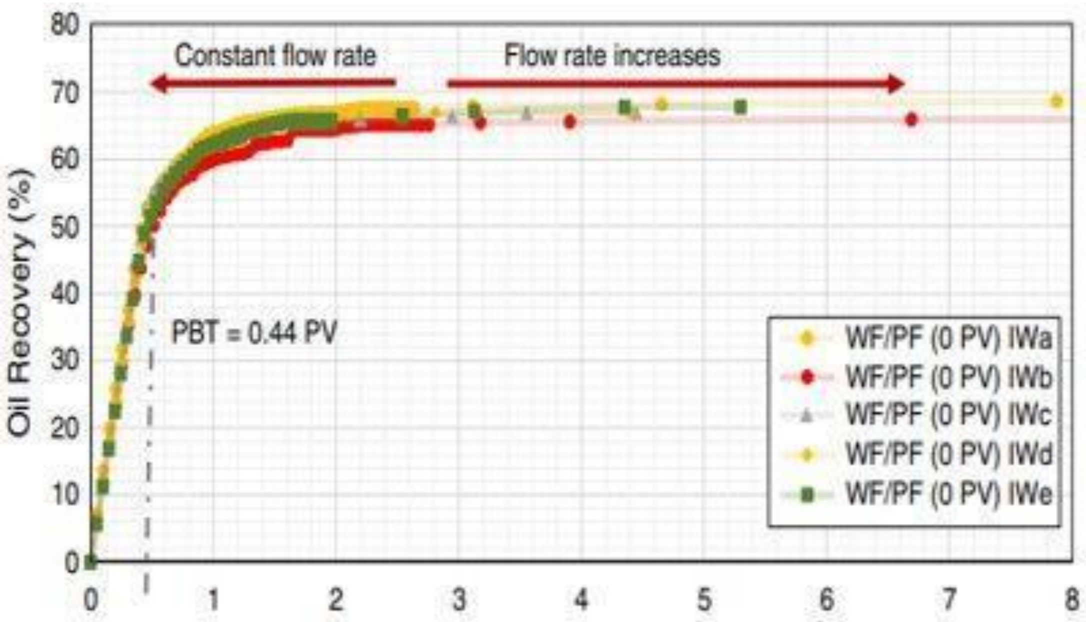

Figure 4.9. *Oil Recovery Factor of Five Experiment Performed (Morejón, 2019)*

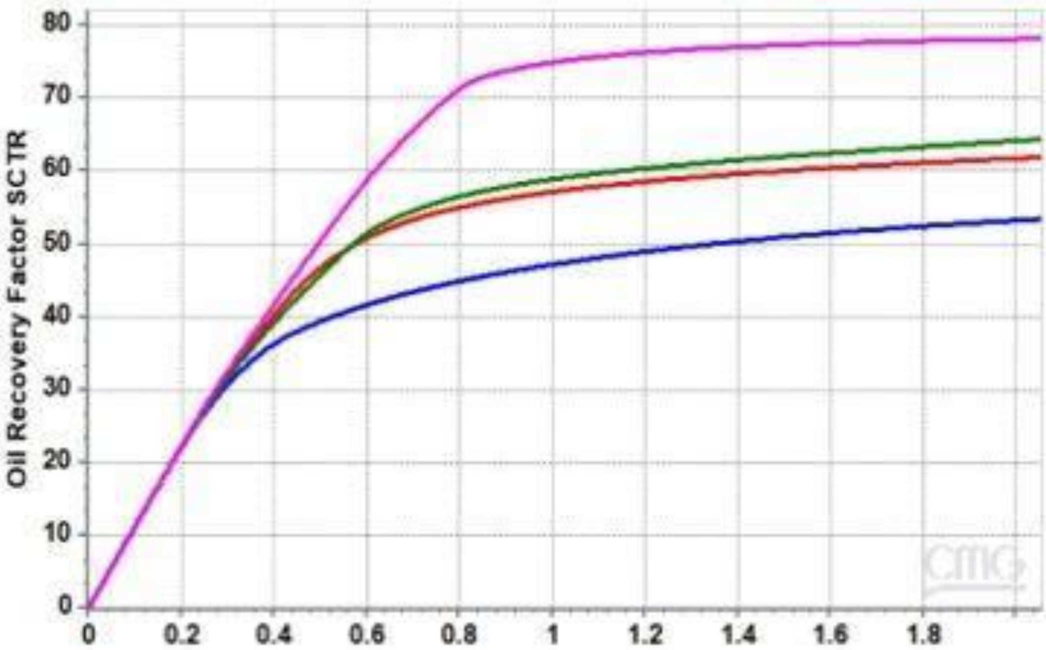

Figure 4.10. *Four Case Scenario of Polymer Oil Recovery Factor (Albahri, 2020)*

Total Summary of the Results of two Different Scenarios

Below are two tables of previously published works from J. L. Juárez morejón, 2019 and albahri, 2020 with the objective of comparing the results obtained from there respective oil recovery factor sctr(%) which is the major aim of this research.

Table 4.2.
Oil Recovery Factor From Morejón, 2019

Description from Morejón	**Recovery Factor sctr (%)**	**Percentage of Polymer Used**
Oil production with 2 producers and 1 water injector	66%	none
Oil production with 2 producers and 1 polymer injector	66.5%	11%
Oil production with polymer injector 1 polymer injector	67%	14%
Oil production with 2 producers and 1 polymer injector	68%	17%
Oil production with 2 producers and 1 polymer injector	68.5%	18%

Table 4.3.

Oil Recovery Factor From Albahri, 2020

Description from Albahri	**Recovery Factor sctr (%)**	**Percentage of Polymer Used**
Oil production with 4 producers and 1 water injector	53.6%	non
Oil production with 4 producers and 1 polymer injector	62.2%	4%
Oil production with 4 producers and 1 polymer injector	64.6%	8%
Oil production with 4 producers and 1 polymer injector	78%	25%

CHAPTER V
Conclusion and Recommendations

Conclusions

In conclusion of this study the effects of polymer injection in an oil reservoir were effectively investigated and analyzed using the computer modelling group Ltd software. A sandstone reservoir data of the highly stratified The brent field reservoir from (sorbie et al,1971) located in the UK. These findings came forth as a result of the study.

- this research, the three different polymer injection scenarios were mainly the focus of this thesis report.
- In terms of the percentages of polymer injected were 5% for the first polymer case,15% for the second polymer case and 23% percentage for the third polymer case.
- After careful simulation and analyzation of these case scenarios while using the CMG stimulator under the (stars) builder it was observed and it proven that the oil recovery factor sctr(bbl) of the three polymer cases were 68.89, 72.78 and 73,97 percentages of the polymer were recovered respectively and it is relatively higher compared to the 5% for no injection case and 56% for water injection case scenario.
- The third polymer case scenario with a 73,97 % oil recovery factor was the best scenario for polymer injection for this research.

.

Recommendations

To achieve reliable results in future investigations, more data will indeed be required. If more information is accessible, fewer assumptions can be made.To accomplish forecasting and historical matching, production data is also required. For this kind of investigation, raw data will produce more reliable results.

- To validate all the presumptions that were made and provide a chance to ascertain the effects of polymer injection, a comparison with an experimental study of a sample of this reservoir would be helpful.
- Future research can also be carried in order to improve on this procedure and help reduce the associated limitations of the procedure**.**

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Appendices

Appendix A

DATA-FILE FOR CMG MODELLING

CMG DATA FILE FOR POLYMER INJECTION SCENARIO

```
RESULTS SIMULATOR STARS 201410
INUNIT FIELD
WSRF WELL 1
WSRF GRID TIME
WSRF SECTOR TIME
OUTSRF GRID PRES SG SO SW TEMP
OUTSRF WELL LAYER NONE
SHEAREFFEC SHV
WPRN GRID 0
OUTPRN GRID NONE
OUTPRN RES NONE
**  Distance units: ft
RESULTS XOFFSET           0.0000
RESULTS YOFFSET           0.0000
RESULTS ROTATION           0.0000  **  (DEGREES)
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0
**
***********************************************************************
*******
** Definition of fundamental cartesian grid
**
***********************************************************************
*******
GRID VARI 30 30 5
KDIR DOWN
DI IVAR
 30*30
DJ JVAR
 30*30
```

```
DK ALL
 4500*35
DTOP
 900*7300
PERMI KVAR
 12 60 600 60 12
**  0 = null block, 1 = active block
NULL CON            1
POR CON          0.2
PERMJ KVAR
 12 60 600 60 12
PERMK CON           10
**  0 = pinched block, 1 = active block
PINCHOUTARRAY CON            1
END-GRID
** Model and number of components
** Model and number of components
** Model and number of components
MODEL 4 4 4 3
COMPNAME 'Water' 'Polymer' 'Salt' 'Dead_Oil'
CMM
0 8000 58.4425 130.485
PCRIT
0 0 0 0
TCRIT
0 0 0 0
PRSR 14.6488
TEMR 194
PSURF 14.6488
TSURF 62.33
MASSDEN
61.2266 61.2266 61.2266 57.16
CP
1e-006 1e-006 1e-006 1.44578e-005
```

CT1

0.000103937 0.000103937 0.000103937 0.000488112

AVG

0 0 0 0

BVG

0 0 0 0

AVISC

0.307 7.12965 0.307 1.046

BVISC

194 194 194 194

VSMIXCOMP 'Polymer'

VSMIXENDP 0 1.69064e-006

VSMIXFUNC 0 0.132255 0.302185 0.472116 0.641826 0.689027 0.736227 0.790959 0.860639 0.93032 1

** velocity viscosity

** Use the following keywords for a smooth shear effect that fits the data in SHEARTAB: SHEARTHIN 0.889076 0.193598

SHEARTAB

0.193598 9.59314

0.328084 10.584

3.28084 6.48

*VSSALTCMP 'Salt' 0.000308551 -0.427773

** Reaction specification

STOREAC

0 1 0 0

STOPROD

443.951 0 0 0

RPHASE

0 1 0 0

RORDER

0 1 0 0

EACT 0

FREQFAC 0.00385082

ROCKFLUID

```
RPT 1 STONE2 WATWET
INTCOMP 'Polymer' ADS
DTRAPW 0
DTRAPN 0
**       Sw        krw       krow
SWT
 SMOOTHEND QUAD
       0.22          0   0.990584
      0.235          0   0.912564
       0.25          0   0.839672
   0.283125  0.00238844   0.695677
    0.31625  0.00494024   0.573013
   0.349375  0.00772841   0.469296
     0.3825   0.0108502   0.382267
   0.415625   0.0144259   0.309797
    0.44875   0.0186002   0.249887
   0.481875   0.0235435   0.200669
      0.515   0.0294535    0.16041
   0.548125   0.0365559   0.127516
    0.58125   0.0451065   0.100532
   0.614375   0.0553917  0.0781468
     0.6475   0.0677301  0.0591978
   0.680625   0.0824736   0.042675
    0.71375    0.100009  0.0277275
   0.746875    0.120757  0.0136713
       0.78    0.145176          0
       0.89    0.259211          0
          1      0.4409          0
**       Sl        krg       krog
SLT
      0.688   0.0139491          0
     0.7075   0.0128697  0.000590434
      0.727    0.011818  0.0027629
     0.7465   0.0107939  0.00722951
```

```
0.766  0.00979752     0.014865
0.7855  0.00882882    0.0267266
0.805   0.0078878    0.0440757
0.8245  0.00697446    0.0683997
0.844   0.0060888     0.101436
0.8635  0.00523082     0.145195
0.883  0.00440052     0.201989
0.9025   0.0035979     0.274454
0.922  0.00282296     0.365581
0.9415   0.0020757     0.478746
0.961  0.00135612     0.617735
0.9805  0.00066422     0.786778
1          0     0.990584
ADSCOMP 'Polymer' WATER
ADSPHBLK W
ADSTABLE
**     Mole Fraction  Adsorbed moles per unit pore volume
**     Mole Fraction  Adsorbed moles per unit pore volume
                0                            0
2.254749671e-006                  3.111839011e-005
ADMAXT 3.11184e-005
ADRT 7.7796e-007
PORFT 0.9
RRFT 5
INTERP_ENDS ON
INITIAL
VERTICAL DEPTH_AVE

INITREGION 1
REFPRES 3700
REFDEPTH 7400
DWOC 7475
DGOC 7300
MFRAC_WAT 'Water' CON     0.999691
```

```
MFRAC_WAT 'Salt' CON  0.000308551
MFRAC_OIL 'Dead_Oil' CON           1
NUMERICAL
RUN
DATE 2021 1 1

DTWELL 1
**
WELL  'Inj-1'
INJECTOR UNWEIGHT 'Inj-1'
INCOMP  WATER  0.76072277  0.230769872  0.00850735848  0.0
TINJW  120.0
OPERATE  MAX  BHP  8000.0  CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF      GEOA  'Inj-1'
** UBA              ff         Status  Connection
   15 15 1        1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   15 15 2        1.0  OPEN    FLOW-FROM  1
   15 15 3        1.0  OPEN    FLOW-FROM  2
   15 15 4        1.0  OPEN    FLOW-FROM  3
   15 15 5        1.0  OPEN    FLOW-FROM  4
LAYERXYZ  'Inj-1'
** perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length
   15  15  1    435.000000    435.000000    7317.500000    435.000000    435.000000
7335.000000  17.500000
   15  15  2    435.000000    435.000000    7335.000000    435.000000    435.000000
7370.000000  35.000000
   15  15  3    435.000000    435.000000    7370.000000    435.000000    435.000000
7405.000000  35.000000
   15  15  4    435.000000    435.000000    7405.000000    435.000000    435.000000
7440.000000  35.000000
   15  15  5    435.000000    435.000000    7440.000000    450.000000    421.153846
7468.942307  35.417130
```

```
**
WELL  'Prod-1001'
PRODUCER 'Prod-1001'
OPERATE  MAX  STO  1500.0  CONT
MONITOR  MIN  STO  10.0  SHUTIN
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'Prod-1001'
** UBA          ff        Status  Connection
   3 3 1       1.0  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   3 3 2       1.0  OPEN   FLOW-TO  1
   3 3 3       1.0  OPEN   FLOW-TO  2
   3 3 4       1.0  OPEN   FLOW-TO  3
   3 3 5       1.0  OPEN   FLOW-TO  4
LAYERXYZ  'Prod-1001'
** perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length
   3 3 1  75.000000  75.000000  7317.500000  75.000000  75.000000  7335.000000
17.500000
   3 3 2  75.000000  75.000000  7335.000000  75.000000  75.000000  7370.000000
35.000000
   3 3 3  75.000000  75.000000  7370.000000  75.000000  75.000000  7405.000000
35.000000
   3 3 4  75.000000  75.000000  7405.000000  75.000000  75.000000  7440.000000
35.000000
   3 3 5  75.000000  75.000000  7440.000000  90.000000  75.000000  7471.849999
35.205432
**
WELL  'Prod-1002'
PRODUCER 'Prod-1002'
OPERATE  MAX  STO  1500.0  CONT
MONITOR  MIN  STO  10.0  SHUTIN
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'Prod-1002'
```

```
** UBA          ff        Status  Connection
   28 3 1       1.0  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   28 3 2       1.0  OPEN   FLOW-TO  1
   28 3 3       1.0  OPEN   FLOW-TO  2
   28 3 4       1.0  OPEN   FLOW-TO  3
   28 3 5       1.0  OPEN   FLOW-TO  4
**
WELL  'Prod-1003'
PRODUCER 'Prod-1003'
OPERATE  MAX  STO  1500.0  CONT
MONITOR  MIN  STO  10.0  SHUTIN
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'Prod-1003'
** UBA          ff        Status  Connection
   3 28 1       1.0  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   3 28 2       1.0  OPEN   FLOW-TO  1
   3 28 3       1.0  OPEN   FLOW-TO  2
   3 28 4       1.0  OPEN   FLOW-TO  3
   3 28 5       1.0  OPEN   FLOW-TO  4
**
WELL  'Prod-1004'
PRODUCER 'Prod-1004'
OPERATE  MAX  STO  1500.0  CONT
MONITOR  MIN  STO  10.0  SHUTIN
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'Prod-1004'
** UBA           ff        Status  Connection
   28 28 1       1.0  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   28 28 2       1.0  OPEN   FLOW-TO  1
   28 28 3       1.0  OPEN   FLOW-TO  2
   28 28 4       1.0  OPEN   FLOW-TO  3
   28 28 5       1.0  OPEN   FLOW-TO  4
```

DATE 2021 2 1.00000
DATE 2021 3 1.00000
DATE 2021 4 1.00000
DATE 2021 5 1.00000
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DATE 2021 7 1.00000
DATE 2021 8 1.00000
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DATE 2024 4 1.00000
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DATE 2024 8 1.00000
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DATE 2027 12 1.00000

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STOP

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DATE 2030 10 1.00000

DATE 2030 11 1.00000

DATE 2030 12 1.00000

DATE 2031 1 1.00000

STOP

DATE 2040 1 1.00000

RESULTS PVTIMEX VISCREGION 1

RESULTS PVTIMEX PVTREGION 1 FALSE

RESULTS PVTIMEX TABLECOLS P RS BO BG VISO VISG DENOIL DENGAS CO

RESULTS PVTIMEX TABLE 101.325 1.31527 1.06638 1.25156 0.541717 0.0125487 725.806 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.465 1.31607 1.06638 1.24983 0.541708 0.0125487 725.806 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.605 1.31687 1.06638 1.24811 0.541699 0.0125487 725.807 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.745 1.31767 1.06638 1.24639 0.541691 0.0125487 725.808 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.885 1.31847 1.06638 1.24468 0.541682 0.0125487 725.808 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.024 1.31927 1.06639 1.24297 0.541673 0.0125487 725.802 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.164 1.32007 1.06639 1.24127 0.541665 0.0125487 725.803 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.304 1.32087 1.06639 1.23957 0.541656 0.0125487 725.804 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.443 1.32167 1.06639 1.23788 0.541647 0.0125487 725.805 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.583 1.32246 1.06639 1.23619 0.541639 0.0125488 725.805 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.723 1.32326 1.0664 1.2345 0.54163 0.0125488 725.799 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.862 1.32407 1.0664 1.23282 0.541621 0.0125488 725.8 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.002 1.32487 1.0664 1.23115 0.541613 0.0125488 725.801 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.142 1.32567 1.0664 1.22948 0.541604 0.0125488 725.801 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.281 1.32647 1.0664 1.22781 0.541595 0.0125488 725.802 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.421 1.32727 1.06641 1.22615 0.541587 0.0125488 725.796 0 4.35113e-006

RESULTS PVTIMEX TABLE 6288.02 58.506 1.03846 0.0182702 0.541587 0.0140458 745.327 0 4.35113e-006

RESULTS PVTIMEX TABLE 12472.6 131.361 1.01195 0.00860589 0.541587 0.0169274 764.858 0 4.35113e-006

RESULTS PVTIMEX TABLE 18657.2 212.208 0.991815 0.00571339 0.541587 0.0208734 780.384 0 4.05367e-006

RESULTS PVTIMEX TABLE 24841.8 298.779 0.997402 0.0044861 0.541587 0.0251685 776.012 0 2.79676e-006

RESULTS PVTIMEX TABLE 31026.4 389.888 1.00147 0.00385085 0.541587 0.0293038 772.859 0 2.09693e-006

RESULTS PVTIMEX TRES 90

RESULTS PVTIMEX BPP 15

RESULTS PVTIMEX BWI 1.01

RESULTS PVTIMEX DENSITYWATER 984.335

RESULTS PVTIMEX VISCOSITYWATER 0.307

RESULTS PVTIMEX WATERCVW 0

RESULTS PVTIMEX DENSITYOIL 772.731

RESULTS PVTIMEX GASGRAVITY 0.78

RESULTS PVTIMEX WATERCOMP 1.45038e-007

RESULTS PVTIMEX REFPW 25510.6

RESULTS PVTIMEX CVO 0

RESULTS PVTIMEX VISCPRESSURE 101.3

RESULTS PVTIMEX COMPOSITION 1 1

RESULTS PVTIMEX KVALUETEMP FALSE 400 -99999 0 0.264

RESULTS PVTIMEX END

RESULTS PVTIMEX VISCREGION 1

RESULTS PVTIMEX PVTREGION 1 FALSE

RESULTS PVTIMEX TABLECOLS P RS BO BG VISO VISG DENOIL DENGAS CO

RESULTS PVTIMEX TABLE 101.325 1.31527 1.06638 1.25156 0.541717 0.0125487 725.806 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.465 1.31607 1.06638 1.24983 0.541708 0.0125487 725.806 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.605 1.31687 1.06638 1.24811 0.541699 0.0125487 725.807 0 4.35113e-006

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RESULTS PVTIMEX TABLE 101.885 1.31847 1.06638 1.24468 0.541682 0.0125487 725.808 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.024 1.31927 1.06639 1.24297 0.541673 0.0125487 725.802 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.164 1.32007 1.06639 1.24127 0.541665 0.0125487 725.803 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.304 1.32087 1.06639 1.23957 0.541656 0.0125487 725.804 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.443 1.32167 1.06639 1.23788 0.541647 0.0125487 725.805 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.583 1.32246 1.06639 1.23619 0.541639 0.0125488 725.805 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.723 1.32326 1.0664 1.2345 0.54163 0.0125488 725.799 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.862 1.32407 1.0664 1.23282 0.541621 0.0125488 725.8 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.002 1.32487 1.0664 1.23115 0.541613 0.0125488 725.801 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.142 1.32567 1.0664 1.22948 0.541604 0.0125488 725.801 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.281 1.32647 1.0664 1.22781 0.541595 0.0125488 725.802 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.421 1.32727 1.06641 1.22615 0.541587 0.0125488 725.796 0 4.35113e-006

RESULTS PVTIMEX TABLE 6288.02 58.506 1.03846 0.0182702 0.541587 0.0140458 745.327 0 4.35113e-006

RESULTS PVTIMEX TABLE 12472.6 131.361 1.01195 0.00860589 0.541587 0.0169274 764.858 0 4.35113e-006

RESULTS PVTIMEX TABLE 18657.2 212.208 0.991815 0.00571339 0.541587 0.0208734 780.384 0 4.05367e-006

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RESULTS PVTIMEX TABLE 31026.4 389.888 1.00147 0.00385085 0.541587 0.0293038 772.859 0 2.09693e-006

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RESULTS PVTIMEX BPP 15

RESULTS PVTIMEX BWI 1.01

RESULTS PVTIMEX DENSITYWATER 984.335

RESULTS PVTIMEX VISCOSITYWATER 0.307

RESULTS PVTIMEX WATERCVW 0

RESULTS PVTIMEX DENSITYOIL 772.731

RESULTS PVTIMEX GASGRAVITY 0.78

RESULTS PVTIMEX WATERCOMP 1.45038e-007

RESULTS PVTIMEX REFPW 25510.6

RESULTS PVTIMEX CVO 0

RESULTS PVTIMEX VISCPRESSURE 101.3

RESULTS PVTIMEX COMPOSITION 1 1

RESULTS PVTIMEX KVALUETEMP FALSE 400 -99999 0 0.264

RESULTS PVTIMEX END

RESULTS RELPERMCORR NUMROCKTYPE 1

RESULTS RELPERMCORR CORRVALS -99999 -99999 -99999 -99999 -99999 -99999 -99999 -99999

RESULTS RELPERMCORR CORRVALS -99999 -99999 -99999 -99999 1 1 1 1

RESULTS RELPERMCORR CORRVALS_HONARPOUR 0.22 0.25 0.22 0.468 0 0.02 0.2 1000

RESULTS RELPERMCORR NOSWC false

RESULTS RELPERMCORR CALINDEX 6

RESULTS RELPERMCORR STOP

RESULTS PVTIMEX VISCREGION 1

RESULTS PVTIMEX PVTREGION 1 FALSE

RESULTS PVTIMEX TABLECOLS P RS BO BG VISO VISG DENOIL DENGAS CO

RESULTS PVTIMEX TABLE 101.325 1.31527 1.06638 1.25156 0.541717 0.0125487 725.806 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.465 1.31607 1.06638 1.24983 0.541708 0.0125487 725.806 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.605 1.31687 1.06638 1.24811 0.541699 0.0125487 725.807 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.745 1.31767 1.06638 1.24639 0.541691 0.0125487 725.808 0 4.35113e-006

RESULTS PVTIMEX TABLE 101.885 1.31847 1.06638 1.24468 0.541682 0.0125487 725.808 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.024 1.31927 1.06639 1.24297 0.541673 0.0125487 725.802 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.164 1.32007 1.06639 1.24127 0.541665 0.0125487 725.803 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.304 1.32087 1.06639 1.23957 0.541656 0.0125487 725.804 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.443 1.32167 1.06639 1.23788 0.541647 0.0125487 725.805 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.583 1.32246 1.06639 1.23619 0.541639 0.0125488 725.805 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.723 1.32326 1.0664 1.2345 0.54163 0.0125488 725.799 0 4.35113e-006

RESULTS PVTIMEX TABLE 102.862 1.32407 1.0664 1.23282 0.541621 0.0125488 725.8 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.002 1.32487 1.0664 1.23115 0.541613 0.0125488 725.801 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.142 1.32567 1.0664 1.22948 0.541604 0.0125488 725.801 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.281 1.32647 1.0664 1.22781 0.541595 0.0125488 725.802 0 4.35113e-006

RESULTS PVTIMEX TABLE 103.421 1.32727 1.06641 1.22615 0.541587 0.0125488 725.796 0 4.35113e-006

RESULTS PVTIMEX TABLE 6288.02 58.506 1.03846 0.0182702 0.541587 0.0140458 745.327 0 4.35113e-006

RESULTS PVTIMEX TABLE 12472.6 131.361 1.01195 0.00860589 0.541587 0.0169274 764.858 0 4.35113e-006

RESULTS PVTIMEX TABLE 18657.2 212.208 0.991815 0.00571339 0.541587 0.0208734 780.384 0 4.05367e-006

RESULTS PVTIMEX TABLE 24841.8 298.779 0.997402 0.0044861 0.541587 0.0251685 776.012 0 2.79676e-006

RESULTS PVTIMEX TABLE 31026.4 389.888 1.00147 0.00385085 0.541587 0.0293038 772.859 0 2.09693e-006

RESULTS PVTIMEX TRES 90

RESULTS PVTIMEX BPP 15

RESULTS PVTIMEX BWI 1.01

RESULTS PVTIMEX DENSITYWATER 984.335

RESULTS PVTIMEX VISCOSITYWATER 0.307

RESULTS PVTIMEX WATERCVW 0

RESULTS PVTIMEX DENSITYOIL 772.731

RESULTS PVTIMEX GASGRAVITY 0.78

RESULTS PVTIMEX WATERCOMP 1.45038e-007

RESULTS PVTIMEX REFPW 25510.6

RESULTS PVTIMEX CVO 0

RESULTS PVTIMEX VISCPRESSURE 101.3

RESULTS PVTIMEX COMPOSITION 1 1

RESULTS PVTIMEX KVALUETEMP FALSE 400 -99999 0 0.264

RESULTS PVTIMEX END

RESULTS PROCESSWIZ PROCESS 2

RESULTS PROCESSWIZ FOAMYOILMODEL -1

RESULTS PROCESSWIZ SGC 0.15

RESULTS PROCESSWIZ KRGCW 0.0001

RESULTS PROCESSWIZ COALESCENCE -14503.6 FALSE

RESULTS PROCESSWIZ BUBBLEPT -14503.6

RESULTS PROCESSWIZ MINPRESSURE -14503.6 FALSE

RESULTS PROCESSWIZ NUMSETSFOAMY 2

RESULTS PROCESSWIZ PRODTIME 1826

RESULTS PROCESSWIZ FOAMYREACTIONS 0.00295728 0.547645 0.000547645 0.00547645 5.47645e-005

RESULTS PROCESSWIZ VELOCITYFOAMY TRUE

RESULTS PROCESSWIZ CHEMMODEL 0

RESULTS PROCESSWIZ CHEMDATA1 TRUE FALSE TRUE TRUE TRUE 1 2 FALSE FALSE

RESULTS PROCESSWIZ CHEMDATA2 0.075 -99999 0.000308551 -0.427773 0 5 0.9 180 2.81484 3 0

RESULTS PROCESSWIZ CHEMDATA3 2.65 0 0.1 0.16 0.1 0.1

RESULTS PROCESSWIZ FOAMDATA FALSE TRUE FALSE 80 3700 194 1.386 0.693 693 13.86 0 0.02 0.35

RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.02 0 1 0.1 20 0.2 40 0.3 45 0.4 48 0.5 49 0.6 15 0.7 10 0.8 5 0.9 2 1 0.02

RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.1 0 1 0.1 160 0.2 170 0.3 180 0.4 205 0.5 210 0.6 220 0.7 150 0.8 48 0.9 20 1 15

RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.2 0 1 0.1 235 0.2 255 0.3 345 0.4 380 0.5 415 0.6 335 0.7 255 0.8 180 0.9 125 1 40

RESULTS PROCESSWIZ FOAMVISCWEIGHT 1 0.1 0.4 1

RESULTS PROCESSWIZ TABLEIFT 0 18.2

RESULTS PROCESSWIZ TABLEIFT 0.05 0.5

RESULTS PROCESSWIZ TABLEIFT 0.1 0.028

RESULTS PROCESSWIZ TABLEIFT 0.2 0.028

RESULTS PROCESSWIZ TABLEIFT 0.4 0.0057

RESULTS PROCESSWIZ TABLEIFT 0.6 0.00121

RESULTS PROCESSWIZ TABLEIFT 0.8 0.00037

RESULTS PROCESSWIZ TABLEIFT 1 0.5

RESULTS PROCESSWIZ IFTSURFACTANT TRUE 8

RESULTS PROCESSWIZ SURFACTCONC 0 0.05

RESULTS PROCESSWIZ TABLEIFTS 0 23.4

RESULTS PROCESSWIZ TABLEIFTS 0.5 5.163

RESULTS PROCESSWIZ TABLEIFTS 0.75 4.356

RESULTS PROCESSWIZ TABLEIFTS 1 3.715

RESULTS PROCESSWIZ TABLEIFTS 1.25 4.102

RESULTS PROCESSWIZ TABLEIFTS 1.5 3.805

RESULTS PROCESSWIZ TABLEIFTS 1.75 3.521

RESULTS PROCESSWIZ TABLEIFTS 2 2.953

RESULTS PROCESSWIZ TABLEIFTS 0 0.17

RESULTS PROCESSWIZ TABLEIFTS 0.5 0.011

RESULTS PROCESSWIZ TABLEIFTS 0.75 0.005

RESULTS PROCESSWIZ TABLEIFTS 1 0.007

RESULTS PROCESSWIZ TABLEIFTS 1.25 0.007

RESULTS PROCESSWIZ TABLEIFTS 1.5 0.056

RESULTS PROCESSWIZ TABLEIFTS 1.75 0.097

RESULTS PROCESSWIZ TABLEIFTS 2 0.098

RESULTS PROCESSWIZ IFTSURFACTANTSALINITY TRUE 8

RESULTS PROCESSWIZ SURFACTSALINITYCONC 0 0.05

RESULTS PROCESSWIZ TABLEIFTSSALINITY 0 23.4

RESULTS PROCESSWIZ TABLEIFTSSALINITY 15000 5.163

RESULTS PROCESSWIZ TABLEIFTSSALINITY 22500 4.356

RESULTS PROCESSWIZ TABLEIFTSSALINITY 30000 3.715

RESULTS PROCESSWIZ TABLEIFTSSALINITY 37500 4.102

RESULTS PROCESSWIZ TABLEIFTSSALINITY 45000 3.805

RESULTS PROCESSWIZ TABLEIFTSSALINITY 52500 3.521

RESULTS PROCESSWIZ TABLEIFTSSALINITY 60000 2.953

RESULTS PROCESSWIZ TABLEIFTSSALINITY 0 0.17

RESULTS PROCESSWIZ TABLEIFTSSALINITY 15000 0.011

RESULTS PROCESSWIZ TABLEIFTSSALINITY 22500 0.005

RESULTS PROCESSWIZ TABLEIFTSSALINITY 30000 0.007

RESULTS PROCESSWIZ TABLEIFTSSALINITY 37500 0.007

RESULTS PROCESSWIZ TABLEIFTSSALINITY 45000 0.056

RESULTS PROCESSWIZ TABLEIFTSSALINITY 52500 0.097

RESULTS PROCESSWIZ TABLEIFTSSALINITY 60000 0.098

RESULTS PROCESSWIZ ADSORPTION TRUE TRUE FALSE TRUE 2 TRUE

RESULTS PROCESSWIZ ADSPOR 0.2494 0.2494 0.2494

RESULTS PROCESSWIZ ADSSURF 0 0

RESULTS PROCESSWIZ ADSSURF 0.1 27.5

RESULTS PROCESSWIZ ADSALK 0 0

RESULTS PROCESSWIZ ADSALK 0.1 50

RESULTS PROCESSWIZ ADSPOLYMER 0 0

RESULTS PROCESSWIZ ADSPOLYMER 0.1 50

RESULTS PROCESSWIZ ALKALINECONC 0 0.3 0.6

RESULTS PROCESSWIZ ADSSURF2 0 0

RESULTS PROCESSWIZ ADSSURF2 0.1 27.5

RESULTS PROCESSWIZ ADSSURF2 0 0

RESULTS PROCESSWIZ ADSSURF2 0.1 39.5

RESULTS PROCESSWIZ ADSSURF2 0 0

RESULTS PROCESSWIZ ADSSURF2 0.1 51

RESULTS PROCESSWIZ SALINITYPPM 0 30000 60000

RESULTS PROCESSWIZ ADSSURF3 0 0

RESULTS PROCESSWIZ ADSSURF3 0.1 27.5

RESULTS PROCESSWIZ ADSSURF3 0 0

RESULTS PROCESSWIZ ADSSURF3 0.1 39.5

RESULTS PROCESSWIZ ADSSURF3 0 0

RESULTS PROCESSWIZ ADSSURF3 0.1 51

RESULTS PROCESSWIZ VELOCITY 0.0328084 0.328084 3.28084

RESULTS PROCESSWIZ SALINITY 1000 5000 25000

RESULTS PROCESSWIZ COMPPOLY 0 0.03 0.05 0.075

RESULTS PROCESSWIZ COMPPOLY 0 0.03 0.05 0.075

RESULTS PROCESSWIZ COMPPOLY 0 0.03 0.05 0.075

RESULTS PROCESSWIZ POLYVISC 0.413077 3.5 5.2 10.8

RESULTS PROCESSWIZ POLYVISC 0.413077 3.43 5.096 10.584

RESULTS PROCESSWIZ POLYVISC 0.413077 2.1 3.12 6.48

RESULTS PROCESSWIZ COMPSALINITY 0 0.03 0.05 0.075

RESULTS PROCESSWIZ COMPSALINITY 0 0.03 0.05 0.075

RESULTS PROCESSWIZ COMPSALINITY 0 0.03 0.05 0.075

RESULTS PROCESSWIZ SALINITYVISC 0.413077 3.5 5.2 10.8

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RESULTS PROCESSWIZ SALINITY_INITIAL 1000

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RESULTS PROCESSWIZ LSWIREACT FALSE FALSE FALSE FALSE TRUE TRUE TRUE FALSE FALSE FALSE FALSE FALSE FALSE 0.9999

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RESULTS PROCESSWIZ LSWIREACTMIN

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RESULTS PROCESSWIZ LSWIREACTMINMINTEQ

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RESULTS PROCESSWIZ LSWIAQINIT

RESULTS PROCESSWIZ LSWIMIN

RESULTS PROCESSWIZ ISCMODEL -1 FALSE TRUE FALSE FALSE FALSE FALSE FALSE FALSE FALSE

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RESULTS SPEC 'Permeability I'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'Layer 1 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 1

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 12

RESULTS SPEC REGION 'Layer 2 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 2

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 60

RESULTS SPEC REGION 'Layer 3 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 3

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 600

RESULTS SPEC REGION 'Layer 4 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 4

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 60

RESULTS SPEC REGION 'Layer 5 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 5

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 12

RESULTS SPEC SPECKEEPMOD 'YES'

RESULTS SPEC STOP

RESULTS SPEC 'Permeability J'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'Layer 1 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 1

RESULTS SPEC PORTYPE 1

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RESULTS SPEC REGIONTYPE 'REGION_LAYER'

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RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 60

RESULTS SPEC REGION 'Layer 3 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

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RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 600

RESULTS SPEC REGION 'Layer 4 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 4

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 60

RESULTS SPEC REGION 'Layer 5 - Whole layer'

RESULTS SPEC REGIONTYPE 'REGION_LAYER'

RESULTS SPEC LAYERNUMB 5

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 12

RESULTS SPEC SPECKEEPMOD 'YES'

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RESULTS SPEC STOP

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RESULTS SPEC CON 10
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Porosity'
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RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.2
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Grid Thickness'
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RESULTS SPEC STOP
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RESULTS SPEC 'Grid Top'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'Layer 1 - Whole layer'

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RESULTS SPEC LAYERNUMB 1

RESULTS SPEC PORTYPE 1

RESULTS SPEC CON 7300

RESULTS SPEC SPECKEEPMOD 'YES'

RESULTS SPEC STOP

Appendix B

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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 **“ANALYZATION OF THE EFFECT OF POLYMER INJECTION IN AN OIL RESERVOIR, BRENT FIELD, UK''** 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