NEAR EAST UNIVERSITY

INSTITUTE OF GRADUATE STUDIES

DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

ASSESSMENT OF POLYMER, FOAM AND CO2 INJECTIONS FOR HEAVY OIL PRODUCTION USING NUMERICAL SIMULATION

M.Sc. THESIS

Abdirasak Mohamed SAID

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Approval

We certify that we have read the thesis submitted by Abdirasak Mohamed SAID titled **"Assessment of Polymer, Foam and CO_2 Injections for Heavy Oil Production Using Numerical Simulation."** and that in our combined opinion it is fully adequate in scope and quality as a thesis for the degree of Master of Applied Sciences.

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Declaration

I formally certify that the information contained in this thesis, including all data, materials, analyses, and conclusions, was acquired and presented in accordance with the standards of academic integrity and ethical conduct established by the Institute of Graduate Studies at Near East University. I further affirm that, in accordance with the requirements of these rules and conduct, I have appropriately cited and attributed any information and data that are not original to this work.

Abdirasak Mohamed SAID

29/03/2023

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Abdirasak Mohamed SAID

Abstract

Assessment of Polymer, Foam and CO2 Injections for Heavy Oil Production Using Numerical Simulation

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In this study, a number of non-thermal enhanced oil recovery strategies are examined to see which ones are most effective for producing heavy oil. The purpose of the research is to determine the methods that are likely to result in the greatest production rates and the greatest improvement in the recovery of heavy oil. Foam flooding, polymer injection, and carbon dioxide injection are the three Methods that are conducted during the course of the assessment, while a number of different aspects, including cumulative oil, the oil recovery factor and the cumulative water-to-oil ratio are taken into consideration.

Furthermore, as part of the optimization process of these techniques, a thorough comparison was carried out between different injection rates and minimum bottom hole pressures. The goal of this comparison was to determine the optimal combination of injection rate and minimum bottom hole pressure that would result in the most effective and efficient enhanced oil recovery. This involved evaluating the impact of various injection rates (1000 bbl, 1500 bbl for foam and polymer injection, and 1000 scf, 1500 scf for carbon dioxide injection) and minimum bottom hole pressures (1000 psi and 1500 psi) on important performance metrics such as cumulative oil recovery, oil recovery factor, cumulative water-oil ratio, and reservoir characteristics were considered. The results of this evaluation provided a valuable insights into the optimal conditions for using these enhanced oil recovery techniques for heavy oil production.

In conclusion, the research findings suggest that selecting the most suitable method for heavy oil production depends on the reservoir and oil characteristics. And according to the model's outcomes, it can be asserted that the polymer injection technique yields the highest cumulative oil production, followed closely by the foam injection method, where carbon dioxide injection method is considered to be the least effective method based on the results obtained.

Keywords: Heavy Oil, Non-thermal EOR, Polymer Injection, Foam Injection, CO2 Injection.

Özet

Ağır Petrol Üretimi İçin Polimer, Köpük ve CO2 Enjeksiyonlarını Sayısal Simülasyon Kullanılarak Değerlendirilmesi

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MSc, Petrol ve Doğal Gaz Mühendisliği Bölümü

Mart 2023, 87 sayfa

Bu çalışmada, ağır petrol üretimi için hangilerinin en etkili olduğunu görmek için bir dizi termal olmayan geliştirilmiş petrol geri kazanımı stratejisi incelenmektedir. Araştırmanın amacı, üretim oranlarında en fazla artışa ve ağır petrolün geri kazanımında en büyük iyileşmeye yol açması muhtemel yöntemleri belirlemektir. Köpük enjeksiyonu, polimer enjeksiyonu ve karbon dioksit enjeksiyonu, değerlendirme sırasında uygulanan üç Yöntemdir; kümülatif petrol, petrol geri kazanım faktörü, kümülatif su-petrol oranı dahil olmak üzere bir dizi farklı yön de dikkate alınır dikkate alınır.

Ayrıca, bu tekniklerin optimizasyon sürecinin bir parçası olarak, farklı enjeksiyon oranları ve minimum dip delik basınçları arasında kapsamlı bir karşılaştırma yapılmıştır. Bu karşılaştırmanın amacı, en etkili ve verimli gelişmiş petrol geri kazanımıyla sonuçlanacak olan enjeksiyon hızı ile minimum dip delik basıncının optimum kombinasyonunu belirlemekti. Bu, çeşitli enjeksiyon hızlarının (Köpük ve polimer enjeksiyonu için 1000 bbl, 1500 bbl ve karbondioksit enjeksiyonu için 1000 scf, 1500 scf) ve minimum dip delik basınçlarının (1000 psi ve 1500 psi) kümülatif petrol geri kazanımı, petrol geri kazanım faktörü, kümülatif su-petrol oranı ve rezervuar özellikleri gibi önemli performans ölçümleri üzerindeki etkisinin değerlendirilmesini içeriyordu. dikkate alınan.

Bu değerlendirmenin sonuçları, ağır petrol üretimi için bu gelişmiş petrol geri kazanım tekniklerinin kullanılmasına yönelik en uygun koşullara ilişkin değerli bilgiler sağlamıştır. Sonuç olarak, araştırma bulguları, ağır petrol üretimi için en uygun yönteminin seçilmesinin rezervuar ve petrol özelliklerine bağlı olduğunu göstermektedir. Modelden elde edilen sonuçlara göre ise kümülatif petrol açısından en etkili yöntemin polimer enjeksiyon yöntemi olduğu, bunu en az etkili yöntemin karbon dioksit enjeksiyon yöntemi olarak değerlendirildiği köpük enjeksiyon yönteminin takip ettiği söylenebilir. elde edilen sonuçlara dayanmaktadır.

Anahtar Kelimeler: Ağır Petrol, Termal Olmayan EOR, Polimer Enjeksiyonu, Köpük Enjeksiyonu, CO2 Enjeksiyonu.

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List of Abbreviations

Bw:	Water Formation Volume Factor
Bg:	Gas Formation Volume Factor
Bo:	Oil Formation Volume Factor
CMG- STARS:	Reservoir Simulator
CO:	Cumulative Oil
CO_2:	Carbon dioxide
cp:	centipoise
CWOR:	Cumulative Water Oil Ratio
EOR:	Enhanced Oil Recovery
IOR:	Improved Oil Recovery
mD:	milli-Darcy
OOIP:	Original Oil in Place
OPC:	Oilfield Production Consultant
OPEC:	Organization of Petroleum Exporting Countries
OR:	Oil Production Rate
RF:	Oil Recovery Factor from Model
RRF:	Oil Recovery Factor from Reservoir
CRF:	Oil Recovery Factor from Core
scf:	Standard Cubic Feet
Sor:	Residual Oil Saturation
STB:	Stock Tank Barrel
Swi:	Irreducible Water Saturation
ϕ:	Porosity

CHAPTER I

Introduction

There is often a lack of clear differentiation between the terms "EOR" and "IOR", (IOR) which stands for Improved Oil Recovery and Enhanced Oil Recovery (EOR) are both techniques used to increase the amount of oil that can be extracted from an oil reservoir. However, there is a difference between the two techniques. Improved Oil Recovery (IOR) refers to the application of any method or technology that increases the recovery of oil beyond what can be achieved by primary recovery methods. IOR techniques include methods such as water flooding, and horizontal drilling. These methods typically increase the recovery factor of an oil reservoir by up to 10-20%. Enhanced Oil Recovery (EOR), on the other hand, refers specifically to the application of advanced techniques that can increase the recovery factor of an oil reservoir. EOR techniques include methods such as carbon dioxide injection, steam flooding, chemical flooding and microbial enhanced oil recovery. EOR techniques can increase the recovery factor of an oil reservoir by up to 60%. There are three distinct forms oil recovery, which are as follows (Figure 1.1) (Karović-Maričić et al., 2014):

1 First stage recovery (primary oil recovery)

2 Second oil recovery (additional oil extraction techniques)

3 Tertiary stage recovery (enhanced oil recovery)

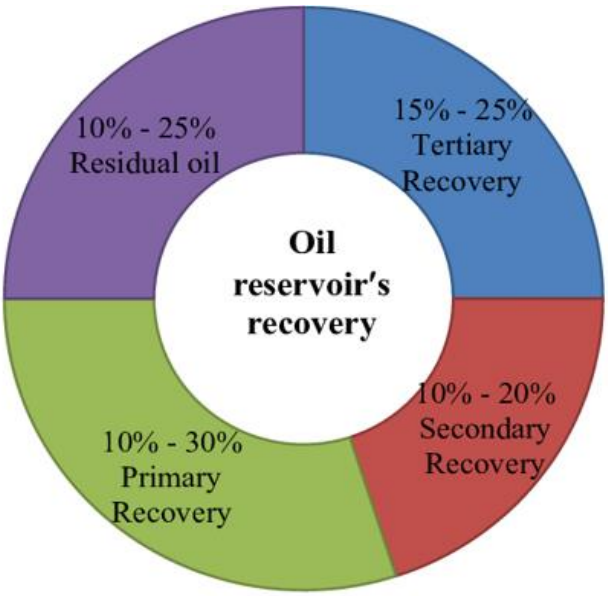

Figure 1.1. *Stages of oil recovery and their recoverable percentage (Karović-maričić et al., 2014).*

Primary Oil Recovery

Primary recovery is reliant on the inherent pressure difference that exists between the oil reservoirs and the surface. The pressure of subsurface oil deposits is naturally higher than that in the wellbore and drive methods, such as water drive, further increase this pressure difference by pushing the hydrocarbons towards the surface. Another common drive mechanism is gas drive, which is employed in cases where oil deposits contain both dissolved and free gas. As the reservoir pressure decreases the free gas expands and propels the hydrocarbons towards the wellbore, often resulting in the formation of oil geysers due to the rapid increase in energy.

Secondary Oil Recovery

Despite the fact that the rate of oil recovery has increased as a direct result of the implementation of secondary oil recovery strategies, same as EOR or Tertiary Recovery, as well as the fact that secondary oil recovery makes use of more effective oil flooding than primary oil recovery does, there is still a considerable quantity of oil that is left in the reservoir after the process. According to work data obtained from all over the globe for reservoirs with limited permeability (tight oil reservoirs) or containing heavy oils, the ultimate oil recovery of primary and secondary oil recovery ranges from 5-10% and 10-25%, respectively, (Figure 1.2) (Wu & Liu, 2020).

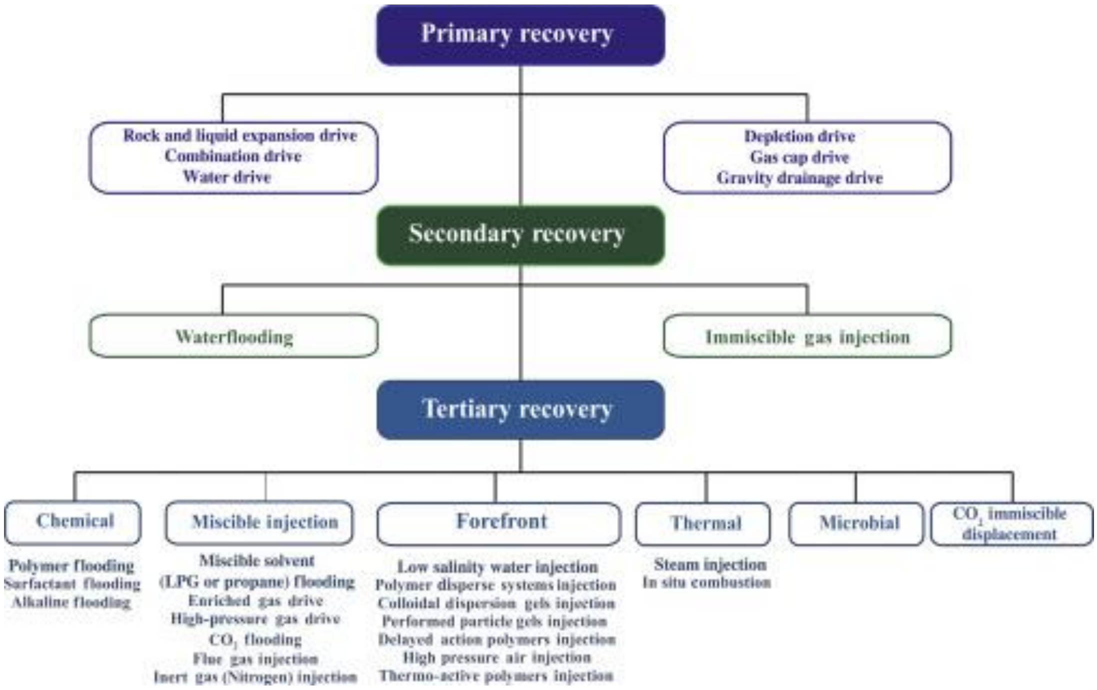

Figure 1.2 *The processes and technologies used to recover oil (Wu & Liu, 2020).*

Enhanced Oil Recovery

Enhanced oil recovery also known as EOR, is a group of techniques that are used in the oil industry and has the dual purpose of reducing the scarcity of crude oil supplies as well as the price of crude oil. It is a techniques for recovering a sizeable quantity of crude oil from wells after the natural extraction processes (Primary Oil Recovery and Secondary Oil Recovery) have been completed.

The natural extraction methods, which relies on the natural pressure of the reservoir to extract crude oil, results in the retention of a considerable amount of the original oil (over 70%) due to a decrease in reservoir pressure. Since this method is dependent on the reservoir's natural pressure, it is imperative to utilize Enhanced Oil Recovery (EOR) techniques. EOR can facilitate the recovery of additional oil by applying advanced processes to increase the efficiency of crude oil extraction.

Additionally, this stage is often referred to as tertiary recovery just as with secondary oil recovery, there are a number of EOR techniques that may be utilized to enhance the temperature or pressure of the reservoir.

EOR methods include modifying the chemical make-up of the reservoir in contrast to secondary recovery methods which use the injection of water or gas to assist transport oil through the wells in a manner that does not affect the actual properties of the hydrocarbon. The density and viscosity of the crude oil change which in effect, makes it less difficult for oil to be moved about in the reservoir (Figure 1.3) (Mokheimer et al., 2019).

The potential for oil recovery to reach a maximum of 75% of the Original Oil in Place (OOIP) is a feasible outcome, depending upon the specific Enhanced Oil Recovery (EOR) technique employed. A graphical representation, showed in Figure 1.4, illustrates the anticipated impact of EOR on the projected oil recovery for both the Middle East region and the global scale. As can be seen the Organization of Petroleum Exporting Countries (OPEC) predicted that enhanced oil recovery (EOR) will improve oil output in the Middle East up to the year 2050. This implies that it is projected that the worldwide EOR sector would increase greatly, which indicates the relevance of this methods moving ahead. (Figure 1.4) (Mokheimer et al., 2019).

Thermal and non-thermal EOR techniques are the two main groups that make up this process.

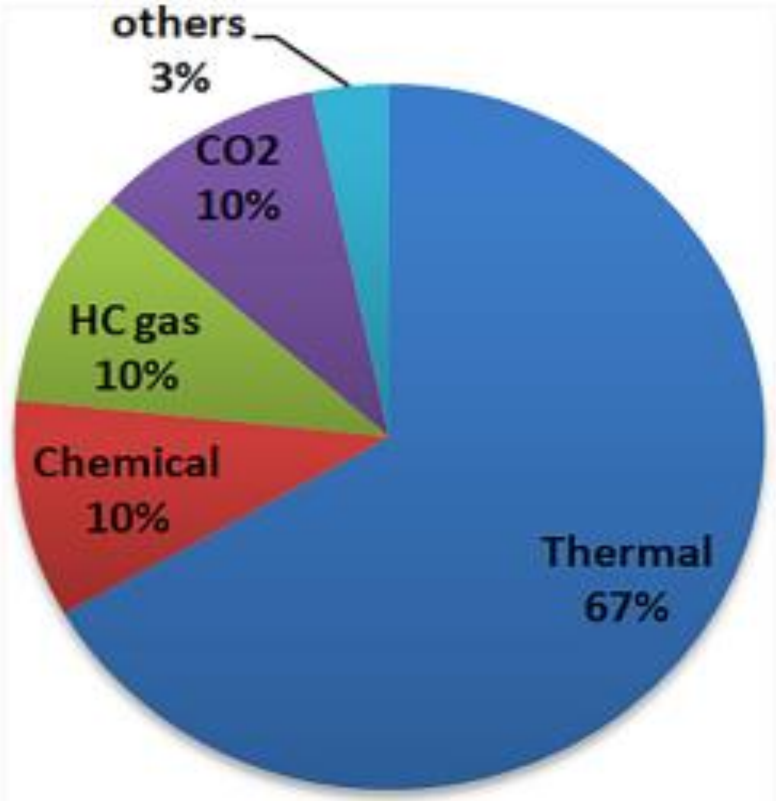

Figure 1.3. *Ratio of EOR methods used around the world (Mokheimer et al., 2019).*

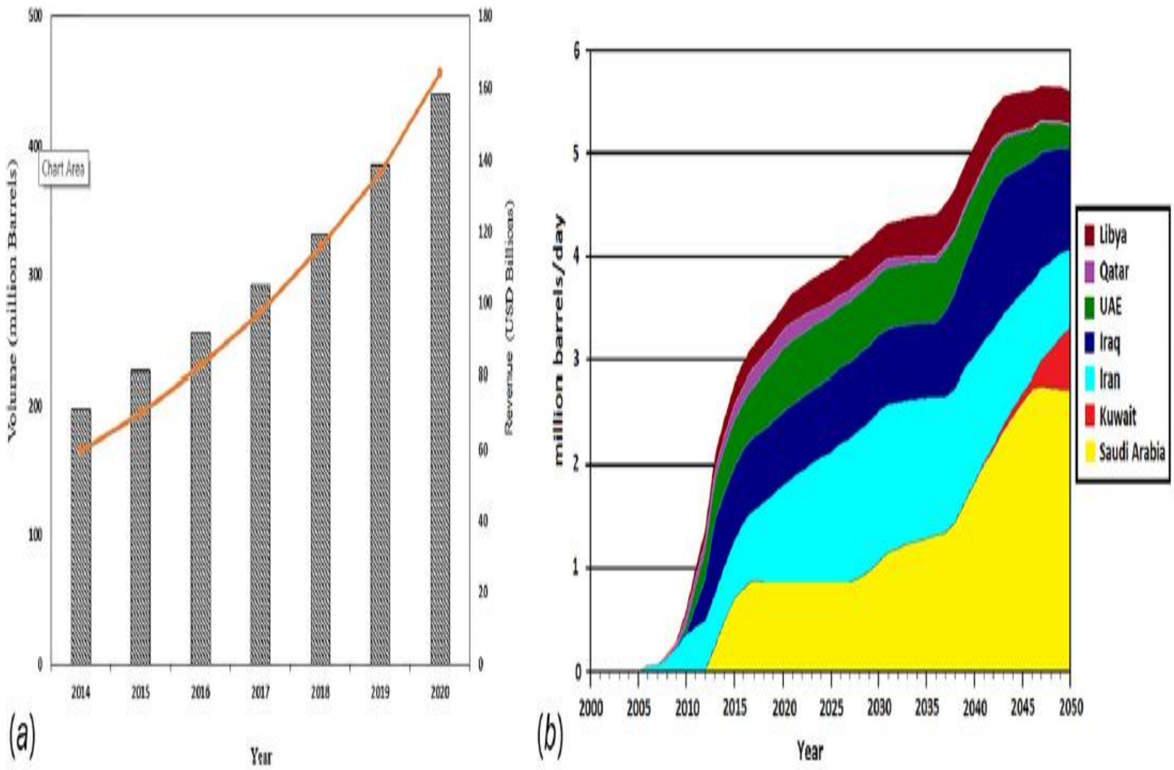

Figure 1.4. *(a) Global EOR market contribution from 2014 to 2020*
(b) Middle East EOR forecast to 2050 (Mokheimer et al., 2019).

Thermal Enhanced Oil Recovery Techniques

Thermal Enhanced Oil Recovery (EOR), as its name suggests, involves the application of heat to increase the temperature of the oil reservoir, reducing the viscosity of the oil. The two most commonly used thermal EOR methods are hot water injection and steam flooding. Other forms of thermal EOR include in situ combustion (also known as fire flooding) and hot fluid injection. High-porosity sandstone and sand are the most suitable formations for thermal recovery techniques.

As shown in Figure1.3, thermal EOR accounts for 67% of the total usage of EOR technologies worldwide and there are different thermal EOR techniques (Figure 1.5) (Mokheimer et al., 2019).

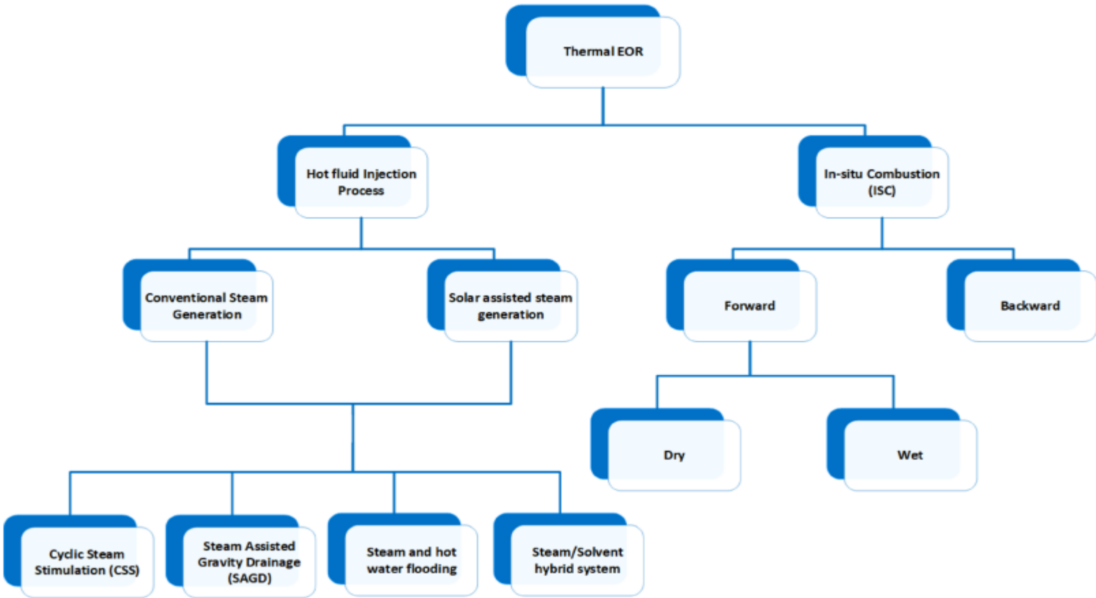

Figure 1.5. *Thermal EOR techniques (Mokheimer et al., 2019).*

Non-thermal Enhanced Oil Recovery Techniques

Non-thermal enhanced oil recovery (EOR) methods refer to a group of techniques that do not involve the application of heat to mobilize oil from the reservoir. Instead, these methods rely on other mechanisms such as chemical, mechanical, or biological processes to increase oil recovery .One of the most commonly used non-thermal EOR methods is chemical EOR.

These techniques involves injecting various chemicals into the reservoir to alter the surface tension between the oil and the reservoir rock, thereby increasing the mobility of the oil. Examples of chemicals used in chemical EOR include surfactants, polymers, and alkalis. Another non-thermal EOR method is microbial EOR, which involves injecting microbes or micro-organisms into the reservoir to facilitate the recovery of oil. The microbes break down the long-chain hydrocarbons in the oil, making it easier to extract from the reservoir.

Mechanical EOR is another non-thermal EOR techniques that involves the use of mechanical force to recover oil. These techniques is typically used in heavy oil reservoirs where the oil is too viscous to flow freely. Mechanical EOR methods include hydraulic fracturing which involves injecting a high-pressure fluid into the reservoir to fracture the rock and create new pathways for the oil to flow. Non-thermal EOR methods offer several advantages over thermal EOR methods, including lower capital and operational costs, reduced environmental impact, and increased flexibility in the choice of recovery method. However, according to reports, non-thermal methods are less prevalent than thermal. They also have some limitations, such as lower recovery rates and the potential for adverse chemical reactions between the injected chemicals and the reservoir rock. Overall, non-thermal EOR methods are an important area of research in the oil and gas industry, and ongoing developments in these techniques are likely to play a significant role in the future of oil production.

Moreover, a variety of diverse Non-thermal enhanced oil recovery (EOR) techniques are available but there are three common non-thermal techniques of enhanced oil recoveries. (Figure 1.6) (Mokheimer et al., 2019).

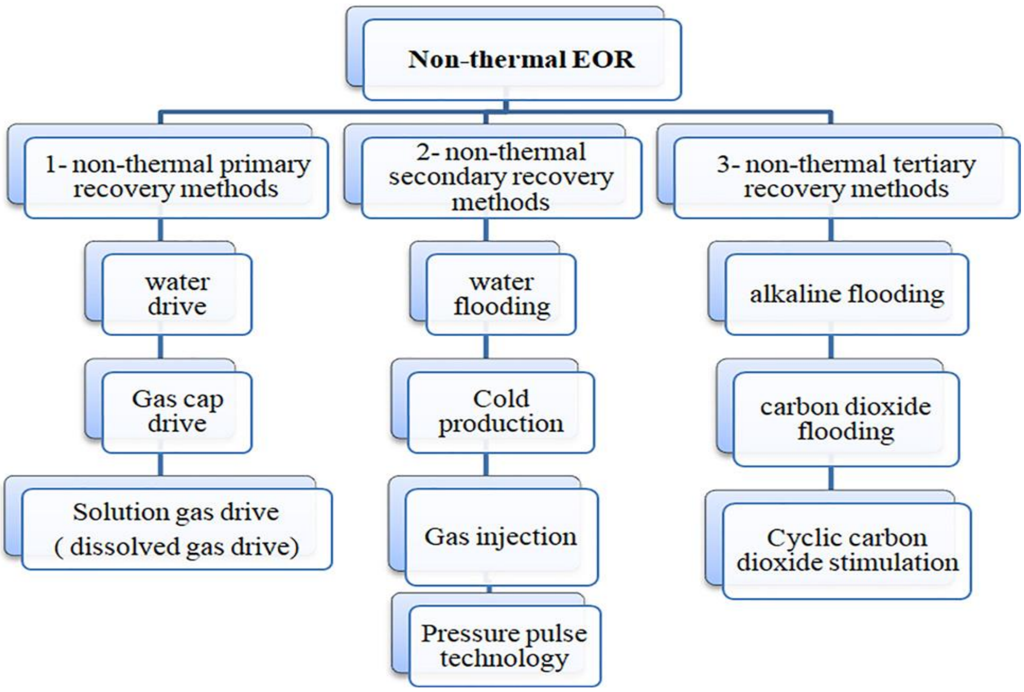

Figure 1.6. *Non-thermal-enhanced oil recovery technologies (Mokheimer et al., 2019).*

Statement of Problem

The majority of Enhanced Oil Recovery (EOR) technologies for heavy oil use thermal methods, which can be quite expensive, especially in thin formations. Therefore, there is a need for low-cost non-thermal EOR methods for heavy oil.

Certain regions such as western Canada contain a number of reservoirs with thin rocks (5 meters or less) in these cases, the remaining oil must be produced using non-thermal EOR methods. This paper focuses on the assessment polymer injection, foam injection and carbon dioxide injection methods using numerical models. The model were subjected to primary production and displacements using carbon dioxide, foam, and aqueous polymer solution, and four injectors were used in the displacement studies.

Limitation

This study is entirely based on data, and these data are obtained by two main sources, one source from previous published report which include heat properties, porosity percentage, initial pressure, oil viscosity, and oil density. The other source provided by Computer Modelling Group (CMG) where many data are available in a form of correlations such as relative permeabilities of oil water and gas, and also formation volume factors of oil, water and gas. One of the main drawbacks is the deficiency of experimental studies on non-thermal EOR. Therefore, there may not be a sufficient amount of evidence to back up this research.

Hypothesis

This study will concentrate on the examination of such methods (polymer, foam and carbon dioxide) using numerical simulation as its primary research tool.

In addition, each method is distinct and comes with its own set of constraints. An attempt has been made to determine the scope of such restrictions. A piece of software known as CMG STARS will be used for simulation and building model in order to test the efficacy of these methods for heavy oil production.

CHAPTER II

Literature Review

Overview

This research endeavors to improve the oil field by comparing various enhanced oil recovery techniques and conducting a thorough analysis of multiple simulation scenarios using CMG simulation software. The impact of injecting different components into the formation, such as carbon dioxide, foam, and polymer, has been examined. The target of this study is to identify the most effective method with high production rate. In order to optimize the well performance, the research also analyzed the effects of adjusting the injection rate and pressure.

Non-thermal EOR

The methods that is ultimately selected and the anticipated pace of recovery are both influenced by a wide range of economic and technical considerations. The only a few non-thermal enhanced recovery techniques can be commercially viable, polymer flooding, foam flooding operations and the use of immiscible carbon dioxide in heavy oils, have been proved to be successful on a commercial scale. This is under the assumption that the reservoir affords acceptable circumstances for the operation of such techniques (Thomas, 2008).

There is a significant amount of interest in chemically enhanced oil recovery due to declining reserves and improvements in surfactant and polymer technologies. They also believe that improved field findings may result from a better knowledge of the chemical interactions at play. They propose using the chemical mixture in successive applications or as premixed slugs (Krumrine and Falcone, 1987).

Techniques for enhancing oil recovery, particularly those intended at reducing oil viscosity have garnered. Figure 2.1 shows the stepwise method of chemical EOR.

Finally, we must remember that these techniques are employed only if they are economically viable; hence, it all relies on the oil's market price. If oil extraction is viable sufficient.

Polymer Injection

Polymer injection is a technique used in the oil and gas industry to improve the recovery of hydrocarbons from reservoirs. The process involves injecting a polymer solution into the reservoir to increase the viscosity of the fluids, reduce the mobility ratio between the reservoir fluids and improve sweep efficiency.

The injection process begins with the preparation of the polymer solution, which is typically a water-based solution containing a high molecular weight polymer such as polyacrylamide. The polymer solution is then injected into the reservoir through an injection well, using high pressure pumps. As the polymer solution enters the reservoir, it mixes with the oil and water, increasing the viscosity of the fluids, this reduces the mobility ratio between the oil and water, making it easier for the oil to flow through the reservoir.

The polymer solution also helps to displace the remaining oil, which can be trapped in the reservoir due to capillary forces. Overally polymer injection can improve the recovery of hydrocarbons from reservoirs by up to 20% making it a valuable technique for the oil and gas industry.

Related Studies

Xie et al., (2019) studied the impact of reservoir heterogeneity on polymer flooding performance in a heavy oil reservoir. The authors used a numerical simulation approach to evaluate the effectiveness of polymer injection under different geological conditions and injection scenarios. They found that polymer flooding could improve oil recovery by up to 20% under certain conditions, but that reservoir heterogeneity was a key factor in determining the success of the injection.

Bai et al., (2018) studied the feasibility of combining polymer flooding with surfactant flooding to enhance oil recovery in a fractured carbonate reservoir. The authors conducted laboratory experiments to optimize the injection parameters and evaluate the effectiveness of the combined approach. They found that the combined flooding technique could improve oil recovery by up to 30% compared to water flooding, and that the optimal injection strategy depended on the reservoir characteristics and the types of polymers and surfactants used.

Rahman et al., (2020) studied the impact of polymer flooding on the well productivity and injectivity in a low-permeability sandstone reservoir. The authors used a numerical simulation approach to evaluate the effectiveness of different injection scenarios and polymer types on oil recovery and well performance. They found that polymer flooding could significantly improve oil recovery, but that the optimal injection strategy depended on factors such as reservoir heterogeneity, polymer type, concentration, and injection rate.

Zhang et al., (2018) investigated the effectiveness of polymer flooding for enhanced oil recovery in a tight sandstone reservoir with high clay content. The authors used laboratory experiments to evaluate the impact of different polymer types and concentrations on oil recovery, and found that polymer flooding could significantly improve oil recovery compared to water flooding. They also found that the optimal injection strategy depended on factors such as reservoir heterogeneity, clay content, and injection rate (Figure 2.1) (Naqvi, 2012).

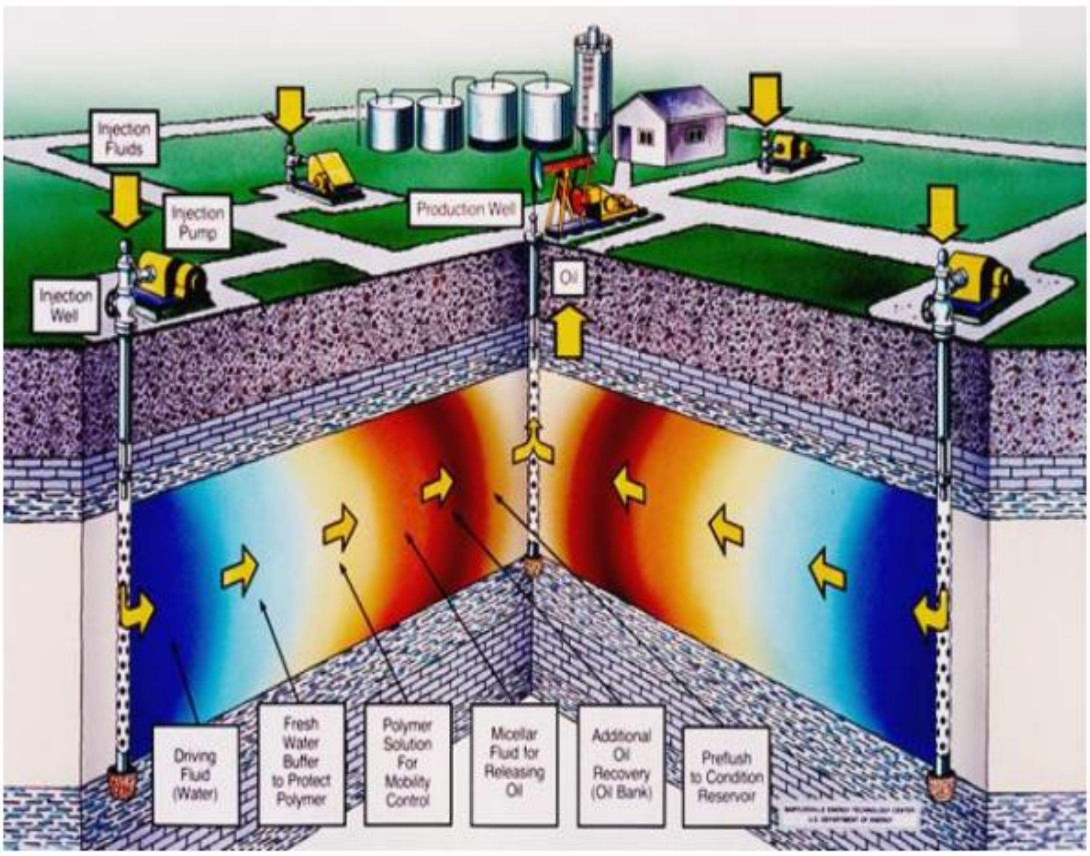

Figure 2.1. *Diagram for chemical enhanced recovery process (Naqvi, 2012).*

Carbon Dioxide Injection

In order to increase the efficiency of oil extraction, carbon dioxide is sometimes injected into oil reservoirs. The first phase of this process involves increasing the pressure in the reservoir to a point where it is adequate for production.

Figure 2.2 shows a well that has previously been used for production and that has been approved for carbon dioxide flooding. In order to do this, water is injected into the producing well, and the well is then shut off. Water not only makes the sweep more effective but also cuts down on the amount of carbon dioxide that is required for it. The pressure in the reservoir is then brought back up to its original level by pumping carbon dioxide into the injection well. This makes it much faster to move the oil from the injection well to the production well. When carbon dioxide enters the oil, it creates a zone where it is miscible with the oil, making it easier to transport. As reservoir fluids are extracted from reservoirs by production wells, carbon dioxide reverts back to its gaseous form, creating a "gas lift" that is equivalent to the original natural reservoir pressure (Buchanan & Timothy, 2011).

Heller et al., (1982) stated that the most common non-thermal method for recovering oil after primary extraction has been ended is carbon dioxide flooding. This method is used to flood the reservoir with carbon dioxide. CO_2 injection can be either miscible or immiscible.

Miscible Carbon Dioxide

Several interactions between the reservoir oil and the injected carbon dioxide are made during the miscible CO_2 EOR process. Carbon dioxide vaporizes the lighter oil fraction before condensing it into the reservoir oil phase during the injection phases of this process. Because the two reservoir fluids are miscible, we get a more mobile fluid with low viscosity and interfacial tension. The primary purpose of miscible carbon dioxide-enhanced oil recovery is to remobilize and considerably reduce residual oil saturation in the reservoir's pore space caused by after-water flooding.

Immiscible Carbon Dioxide

If the reservoir doesn't have enough pressure or the oil doesn't have the right ingredients, the injected carbon dioxide won't be able to mix with it (heavier). After then, another kind of oil displacement that takes place is called an immiscible carbon dioxide flooding. The immiscible carbon dioxide flooding procedure may be used to recover oils with a moderate viscosity if the thermal methods that are often used to do so are unsuccessful, primary function for immiscible carbon dioxide flooding are:

- Oil swelling

- Reduction of viscosity
- Reduction of interfacial tension

The target formations for the application of immiscible CO_2 are those with heavy oils that are unable to achieve miscibility with CO_2 as well as those with reservoirs that are either too deep or too thin for thermal methods to be cost-effective (Ali & Meldau, 1999).

Adding deformer to tank batteries on a regular basis may help to cure the foaming problem. In some cases, the separation of oil and water necessitates the employment of chemicals and heat (Ali & Meldau, 1999)

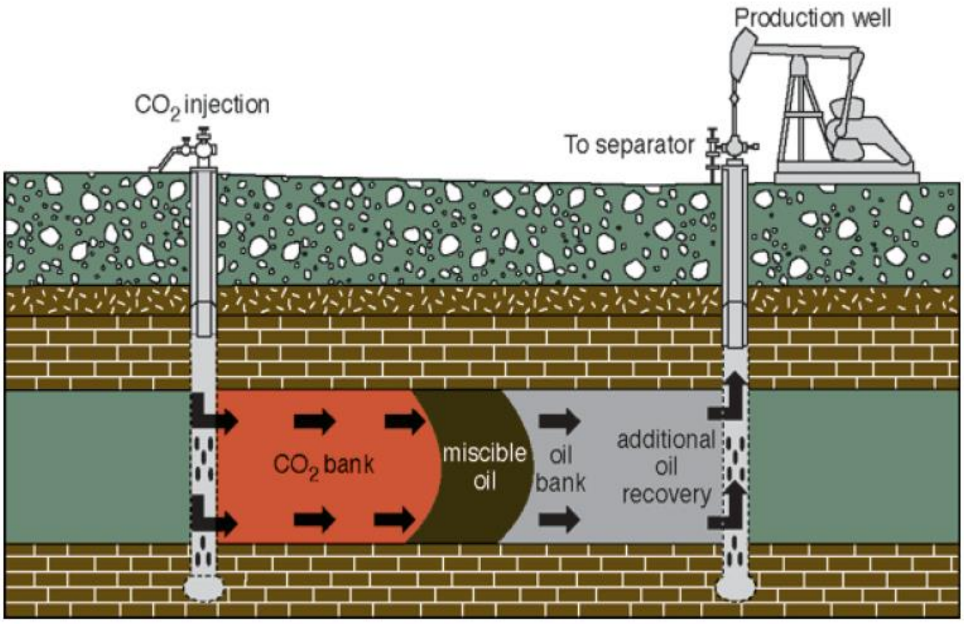

Figure 2.2. *Carbon dioxide injection (Buchanan & Timothy, 2011).*

Mungan (1992), the two reservoir types that can be especially well-suited for carbon dioxide flooding are:

- Carbonate rocks, which have poor injectivity.
- Formations that contain crude oils with a lower saturation level.

The majority of the heavy oil deposits in Saskatchewan have depth of 10 meters or less and also contain underlying sand and water. These formations are not appropriate for thermal procedures because of the substantial vertical heat loss and bottom water steam scavenging, making their use unprofitable. This drives the search to look for recovery methods besides thermal ones for oils that are thin to fairly thick in consistency.

Corrosion and foaming have recently been the most serious problems with the carbon dioxide flooding technique. Formation of carbonic acid is the source of the corrosion issue. Since crude oil has a low specific gravity, a high viscosity, and a high carbon dioxide concentration, foaming issues arise.

Following techniques have helped to reduce the corrosion issue:

- Fiberglass flow pipes for production wells
- Transportation of water and CO_2 in the separate line of injector
- Batch treatment of corrosion and scale inhibitors in injection wells
- Plastic-coated inside of the injection well tubing string

Related Studies

CO_2 injection is a viable technique for revitalizing shale oil resources after initial production. In this work, the authors did a thorough review of the carbon storage literature as well as CO_2 injection in shales over the previous years. Improved models for modeling these methods have been developed in depth, including the classic dual continuum model and the embedded discrete fracture model (EDFM). The heterogeneity impact and upscaling algorithm were explored in relation to shale oil recovery performance (Jia et al., 2019).

In recent years, unconventional shale reservoirs have benefited from an increase in oil recovery due to the injection of carbon dioxide (CO_2). Injection of carbon dioxide may be carried out in a number of different methods. The use of cyclic CO_2 injection is one of the most prevalent techniques, especially in reservoirs that are very distinctive. The purpose of this research is to investigate the possibility for increasing oil recovery from unconventional shale reservoirs through the use of cyclic CO_2 injection, as well as the effect that reservoir thermodynamics, such as pressure and temperature, have on the amount of oil that may be recovered. The experiments were carried out in a tank that had been constructed specifically for the purpose of simulating the cyclic CO_2 injection method (Fakher et al., 2019).

Despite the thermal method's efficacy and high-cost effect in extracting heavy oil extraction. It’s not applicable to deep formations or those with shallow pay zones due to the high heat loss. To increase heavy oil production, several CO_2 injection techniques are used in heavy oil reservoirs. The most effective method has been found is huff and puff CO_2 (Zhou et al., 2018).

New hybrid technique for enhancing ultra-heavy oil recovery in a deep thinly laminated reservoir may be developed by combining the injection of steam which reduces viscosity of oil and carbon dioxide injection to swell the oil. It is put to work investigating methods through which hybrid systems may improve oil recovery rates. In addition to using a viscosity reduction, ultra-heavy oil physicochemical characterization, steam multi-system mixtures, and carbon dioxide are used (Liu et al., 2016).

Foam Injection

A surfactant solution, which is normally a liquid, and air are the two components that go into making foam in the oil fields. It may be used for a variety of purposes, including, promoting oil recovery, and optimizing the flow of fluids in wells. In the process of improved oil recovery, the use of foam serves to lower the viscosity of heavy oil which in turn increases the quantity of oil that can be recovered from a well. In addition, foam is an essential component in both the stimulation of wells and the extinguishing of fires. It does this by either enhancing the flow of fluids or decreasing the amount of oxygen that is available to fuel a blaze (Figure 2.3) (Lima, 2021).

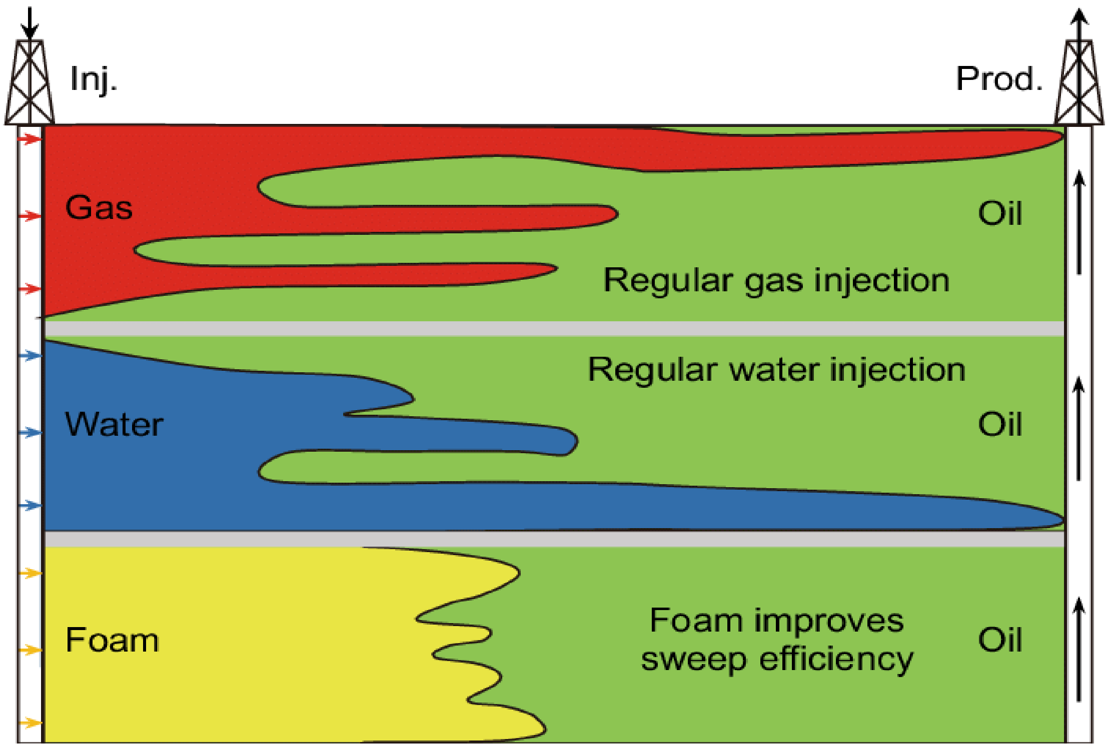

Figure 2.3. *Sweep efficiency for different injection methods (Lima, 2021).*

Limitations

- Impairment of the rock formation: The injection of foam may form a gel-like substance that clogs the pores in the rock and reduces the flow of oil, causing formation damage.
- Environmental impact: Chemical surfactants and other additives in foam can have adverse effects on the environment if not properly managed.
- Ineffective oil recovery: The foam may not effectively mobilize the oil, leading to inefficient recovery.
- Operational difficulties: There can also be operational challenges with foam injection, such as foam stability, compatibility of surfactants, and foam mobility.

To avoid these side effects, it's important to thoroughly evaluate and address the potential consequences of foam injection in EOR. This can be done by choosing appropriate foam additives and surfactants, monitoring foam performance, and optimizing the injection process.

Related Studies

He et al., (2010) studied profile modification of nitrogen foam stream to reduce fingering and improve oil recovery in a heterogeneous multi-facet sandstone reservoir pilot. Temperature, salinity, and oil saturation affected nitrogen foam in a static foam test. An unknown surfactant and foam stabilizer made nitrogen foam suitable for 50°C and salinity under 10000 ppm. In a pilot test, reservoir pressures rose quickly.

During the adsorption process, a component of the condition of the smooth motion gets close to the other referenced boundaries, and the adsorption thickness on the stone is best portrayed as a component of the accessible surfactant volume in the framework rather than by the surfactant fixation (Grigg & Mikhalin, 2007).

There is little doubt that foam reduces the gas's overall penetrability. When originally introduced, the foam technique for gas portability became less portable (Wang and Li, 2016). The movement decrease factor (MRF), which is a ratio of foam movement to gas mobility, illustrates this reduction. MRF = P froth/P gas (Nguyen et al., 2000).

CHAPTER III

Methodology

This study investigates several non-thermal methods for Enhancing oil recovery, the majority of the reported EOR systems for heavy oil are thermal processes. These techniques sometimes come with a high cost-effect especially when applied to thin formation. Low-cost non-thermal EOR methods for heavy oil are required. The assessment of such non-thermal methods (polymer, foam and carbon dioxide injection) using numerical models and to test their efficiency for heavy oil production is the focus of this paper. A software called CMG STARTs has been used for simulation and building model. The reservoir data used in this study are summarized in Table 3.1, whereas the constraints of wells are presented in Table 3.2.

Table 3.1. *Reservoir and Fluid Properties (Bobb & Hosein, 2018).*

Properties	**Values**
Constant porosity, %	30
Permeability varies across the I direction (PERMI), md	300
Permeability of J direction, md	300
Permeability of K direction, md	PERMI*0.1
Reference Pressure, psi	1740
Bubble Point Pressure, psi	1243
Temperature, ˚F	100
API Gravity	21
Viscosity, cp	300
Oil saturation, %	55

Table 3.2. *Injection and production constraints.*

Parameters	**Values**
Maximum bottom hole pressure (Injector)	6200 psi
Maximum surface oil rate (Producer)	12000bbl/d

Research Plan

The aim of this research is to enhance the oil recovery and it has been achieved through a comparative analysis of various enhanced oil recovery techniques, using multiple simulation scenarios being conduct a 35x35x9 Cartesian model.

To optimize the well, the results of changing the injection rates and different applied pressures have been evaluated, to find a best combination. The goal of this optimization was improve the production and minimize cost and risks associated with well operations. It’s important to note that the technical and economic feasibility of these techniques were also considered during the optimization process. Also the simulation covers a time frame of 3 years and a total of 1095 days.

Ultimately, this research serves to determine the most effective enhanced oil recovery technique that can be employed to maximize oil recovery and increase profitability. During this research we compared:

- Different injection rates
- Different applied minimum bottom hole pressure (to get CWOR less than 0.1)

Data Acquisition

This study is entirely based on data, and these data are obtained by two main sources one from one provided from CMG (Computer Modelling Group) where many data are available in form of correlations. The other one was employed in the study. (Bobb & Hosein, 2018). That include heat properties, porosity percentage, initial pressure, thickness, and oil density.

Reservoir Modeling

The process of producing a numerical representation of a subsurface hydrocarbon reservoir is referred to as reservoir modeling. This representation is created using data from geology and engineering. It requires the characterization of fluid reservoirs, which includes the determination of fluid distribution, pressure, and saturation, in addition to the calculation of reservoir parameters like permeability and porosity. The ultimate purpose of reservoir modeling is to increase one's knowledge of the reservoir, maximize production, and predict the amount of hydrocarbons that may ultimately be recovered. After that, the model is put to use for reservoir simulation in order to forecast future performance and enhance the effectiveness of development plans

Reservoir Model

This model of the reservoir covers an area of 30 acres and it's a Cartesian grid with a thickness of 70 feet. The reservoir model in question encompasses an area of 30 acres and is represented by a cartesian grid with a thickness of 70 feet. Figure 3.3 provides a three-dimensional view of the model where the grid and property statistics of this model can be found in Table 3.5.

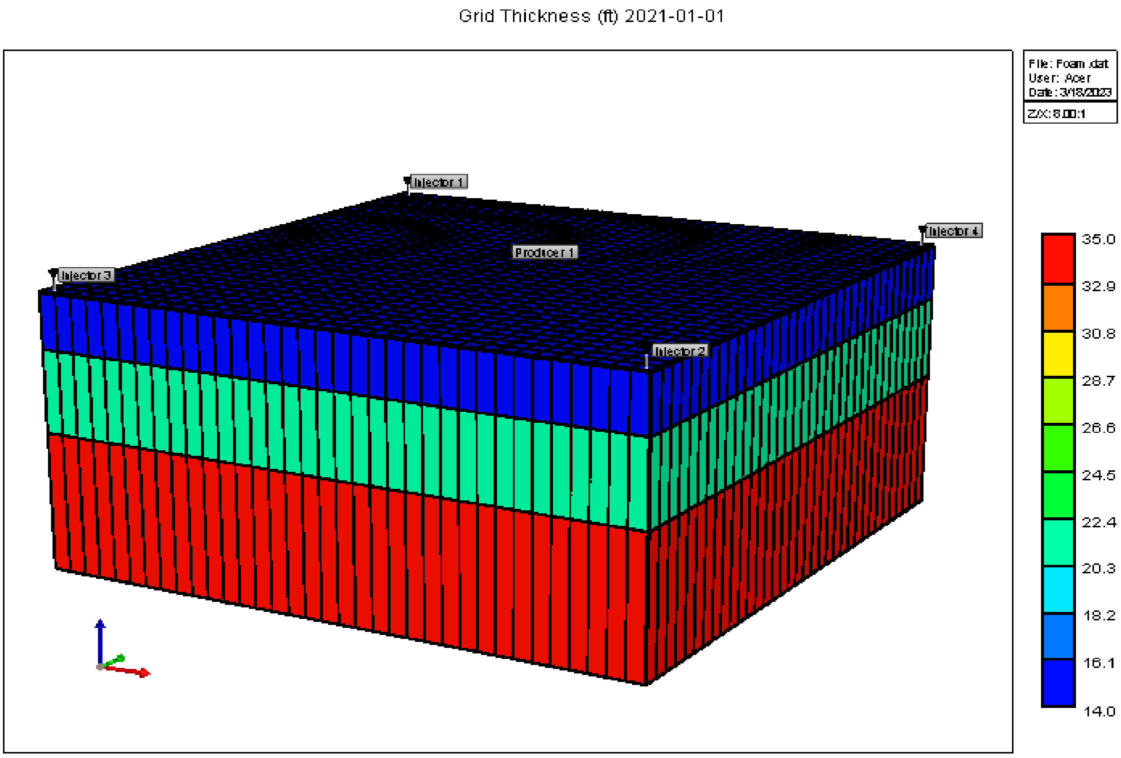

Figure 3.1. *3D view of reservoir model.*

Table 3. 3. *Grid and property statistics of model.*

Properties	**Values**
Gross Formation Volume, ft3	89,168,000
Formation Pore Volume, ft3	26,750,000
Oil Phase Volume, bbl	3,542,416
Aqueous Phase Volume, bbl	952,894

Total Number of Blocks	11025
Thickness, ft	70
Area, Acres	30
Actual block size in X. Y, ft	33.197
Actual block thickness, ft	7.777

Understanding the behavior of fluid properties under varying pressure conditions is crucial in optimizing oil production operations. In this analysis, we present graphs depicting the relationships between pressure and key fluid properties, these graphical representations offer valuable insights into the characteristics and trends exhibited by these properties, providing significant implications for the design and management of oil production processes.

Water Formation Volume Factor versus Pressure

The Figure 3.2 illustrating the relationship between water formation volume factor and pressure demonstrates a notable trend. As pressure increases, the water formation volume factor exhibits a gradual decline, indicating reduced water volume at higher pressures. This relationship is crucial in estimating the amount of water present in reservoirs and predicting the behavior of water during oil recovery processes.

Oil Formation Volume Factor versus Pressure

Examining the oil formation volume factor against pressure provides essential information on oil behavior in reservoirs. Figure 3.3 shows a distinct pattern wherein the oil formation volume factor increases as pressure increases until it reaches a certain point 12205 psi where the graph starts to decline

Gas Formation Volume Factor versus Pressure

The Figure 3.4 showing the gas formation volume factor with respect to pressure offers insights into gas behavior under varying pressure conditions. It reveals an inverse relationship, wherein the gas formation volume factor decreases as pressure increases. This suggests that gas compressibility becomes more significant at higher pressures, leading to a reduction in gas volume.

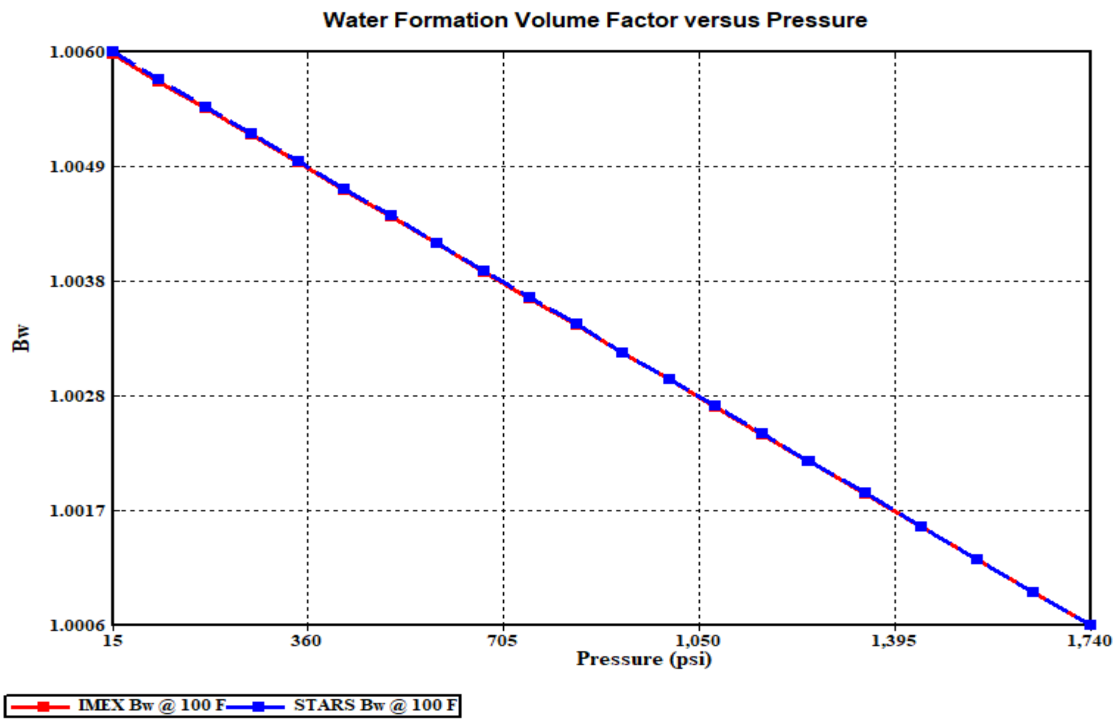

Figure 3.2. *Water formation volume factor versus pressure (at reservoir temperature).*

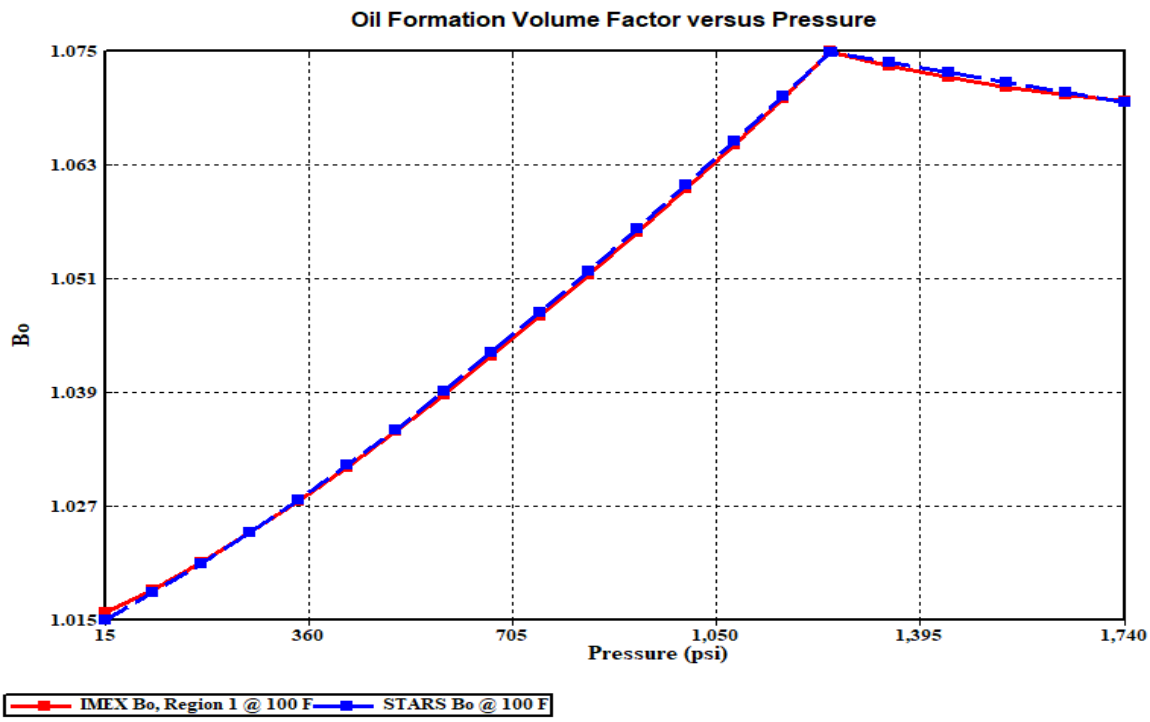

Figure 3.3. *Oil formation volume factor versus pressure (at reservoir temperature).*

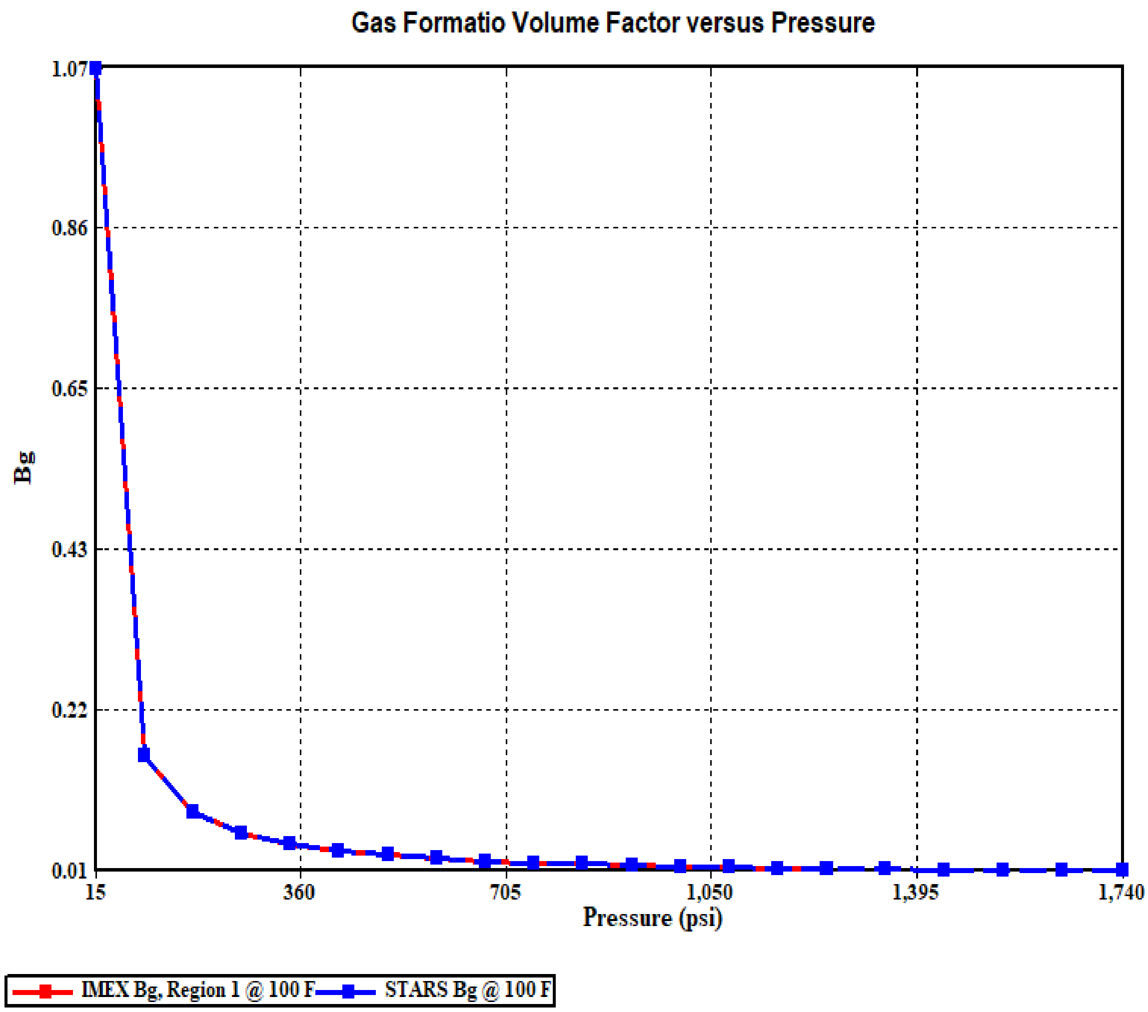

Figure 3.4. *Gas formation volume factor versus pressure (at reservoir temperature).*

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Water Density versus Pressure

Analyzing the Figure 3.5 water density graph in relation to pressure yields valuable information about water properties within the reservoir. As pressure increases, water density exhibits a gradual increase, indicating denser water at higher pressures. This knowledge helps predict water movement within the reservoir and its impact on overall fluid flow dynamics.

Oil Density versus Pressure

The Figure 3.6 representing oil density as a function of pressure offers important insights into oil characteristics. And it shows a reverse of oil formation volume factor, the oil density decreases as the pressure increases until it reaches a certain point (12205 psi) where the graph starts to rise up.

Accurate knowledge of oil density under varying pressure conditions is crucial for reservoir modeling and determining flow behavior during production operations.

Gas Density versus Pressure

Figure 3.7 shows the relationship between gas density and pressure, enabling a comprehensive understanding of gas properties. It showcases a direct correlation between gas density and pressure, with gas density increasing as pressure rises. This relationship assists in predicting gas behavior, reservoir characterization, and gas production optimization.

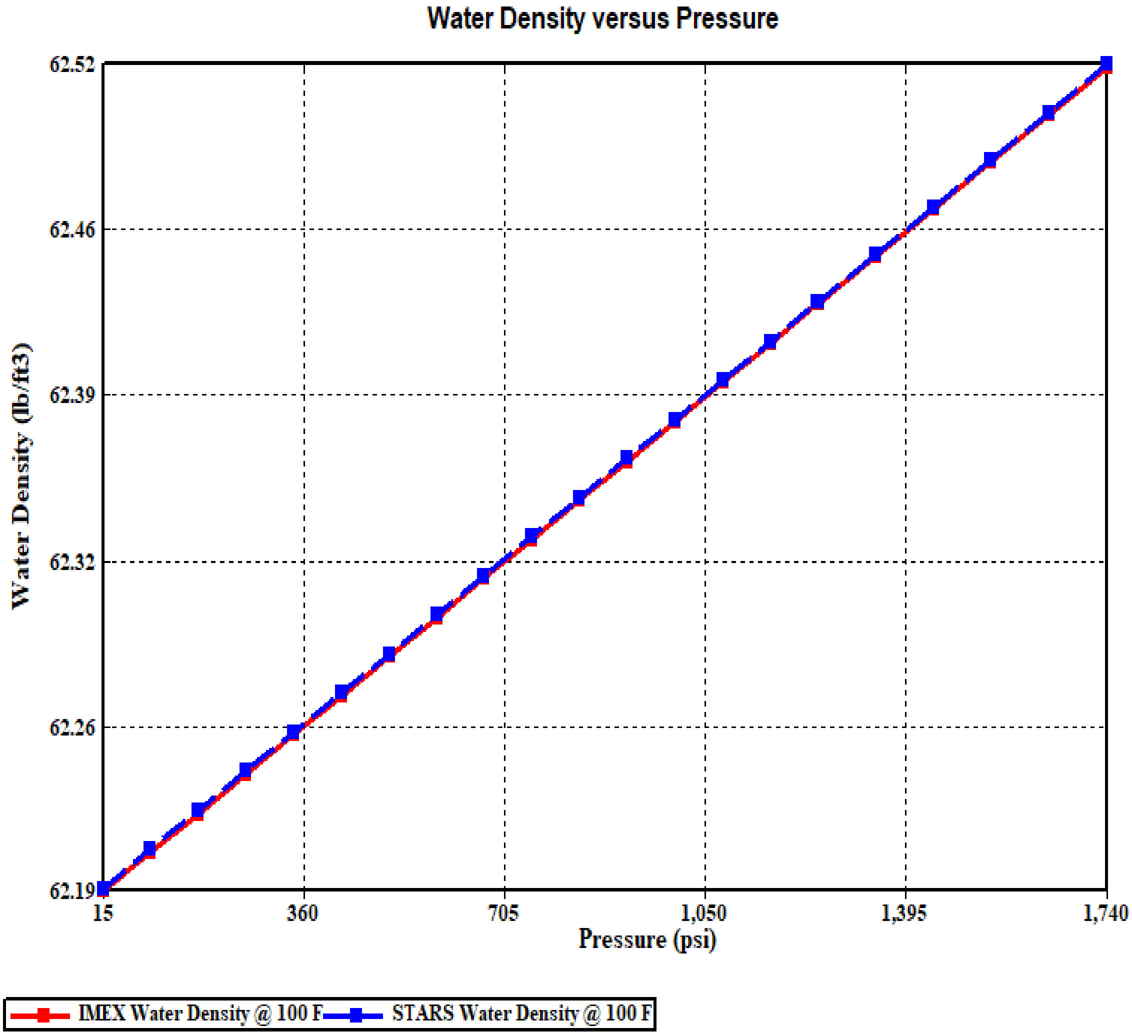

Figure 3.5. *Water density versus pressure (at reservoir temperature).*

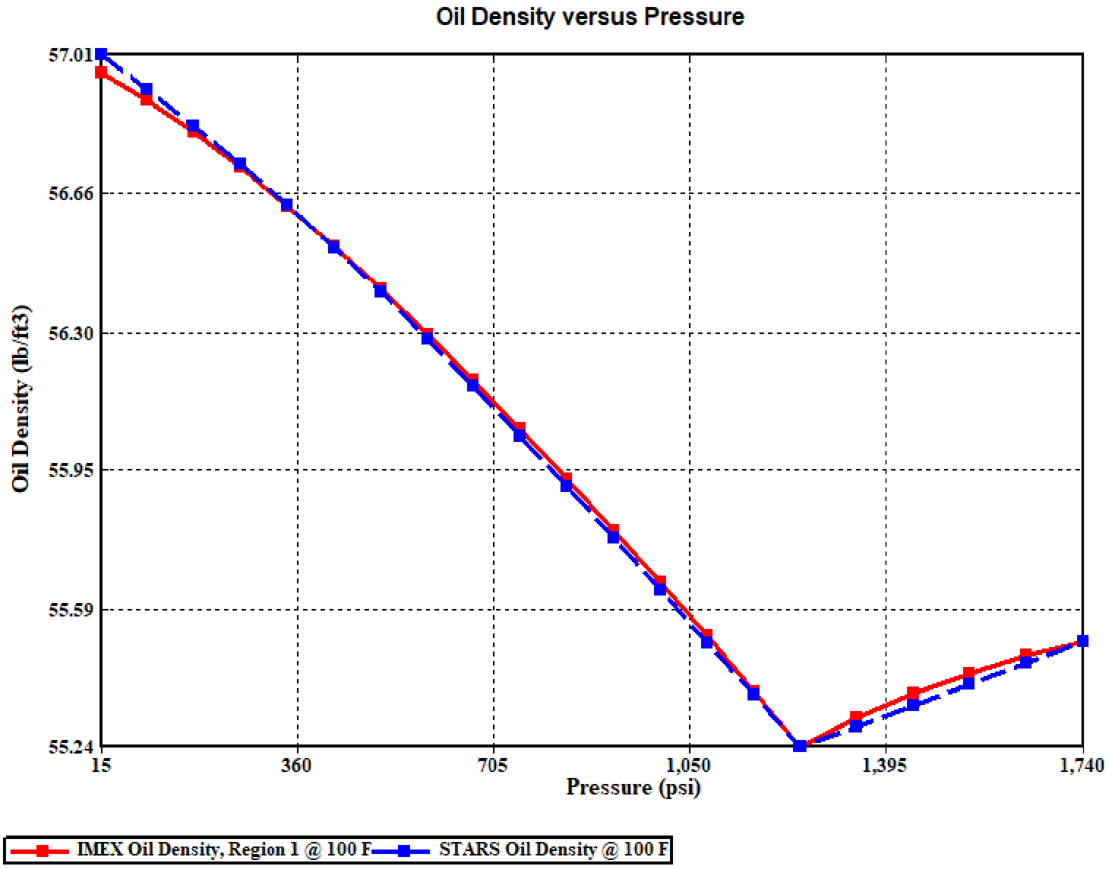

Figure 3.6. *Oil density versus pressure (at reservoir temperature).*

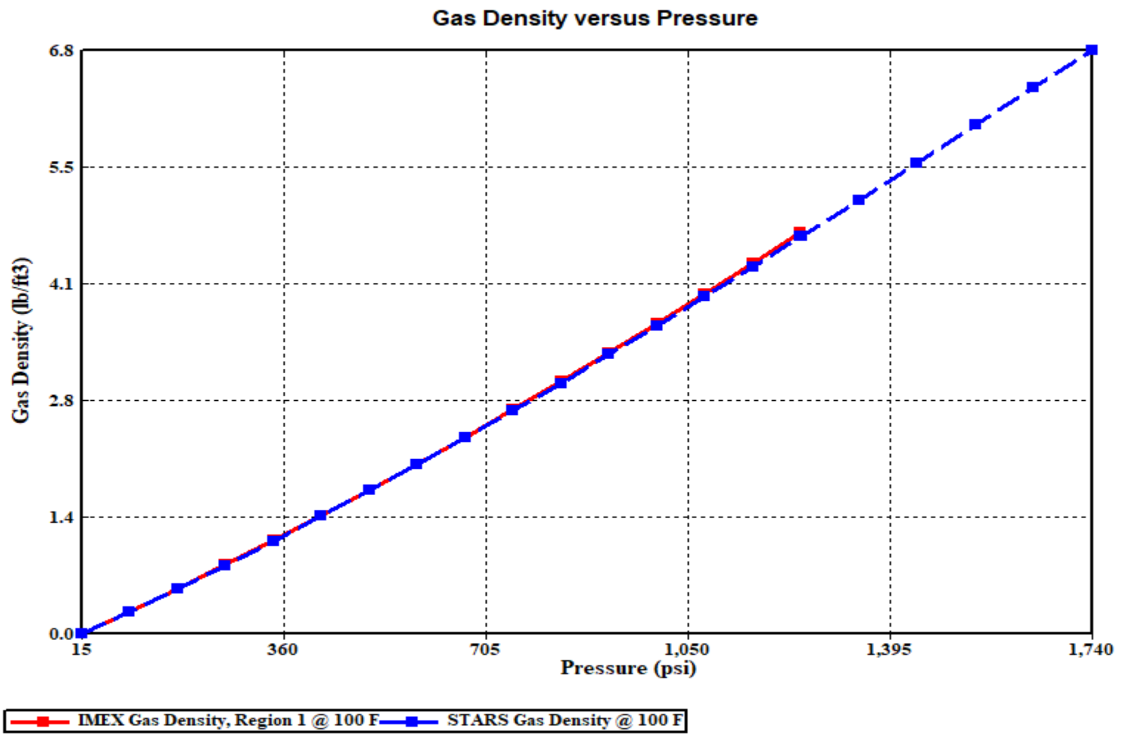

Figure 3.7. *Gas density versus pressure (at reservoir temperature).*

Water Viscosity versus Pressure

Figure 3.8 water viscosity graph in relation to pressure showcases the changes in water viscosity under varying pressure conditions. It demonstrates that water viscosity remains relatively constant with increasing pressure, indicating negligible influence on viscosity. This understanding is critical for accurately modeling water flow within the reservoir and optimizing production strategies.

Oil Viscosity versus Pressure

The Figure 3.9 representing oil viscosity against pressure reveals the impact of pressure on oil viscosity. It displays a gradual decrease in oil viscosity as pressure increases, until it reaches a certain point (1205 psi) where the graph become a constant. Decreasing in oil viscosity implies reduced resistance to flow at higher pressures. This knowledge aids in predicting oil flow behavior and designing efficient extraction methods.

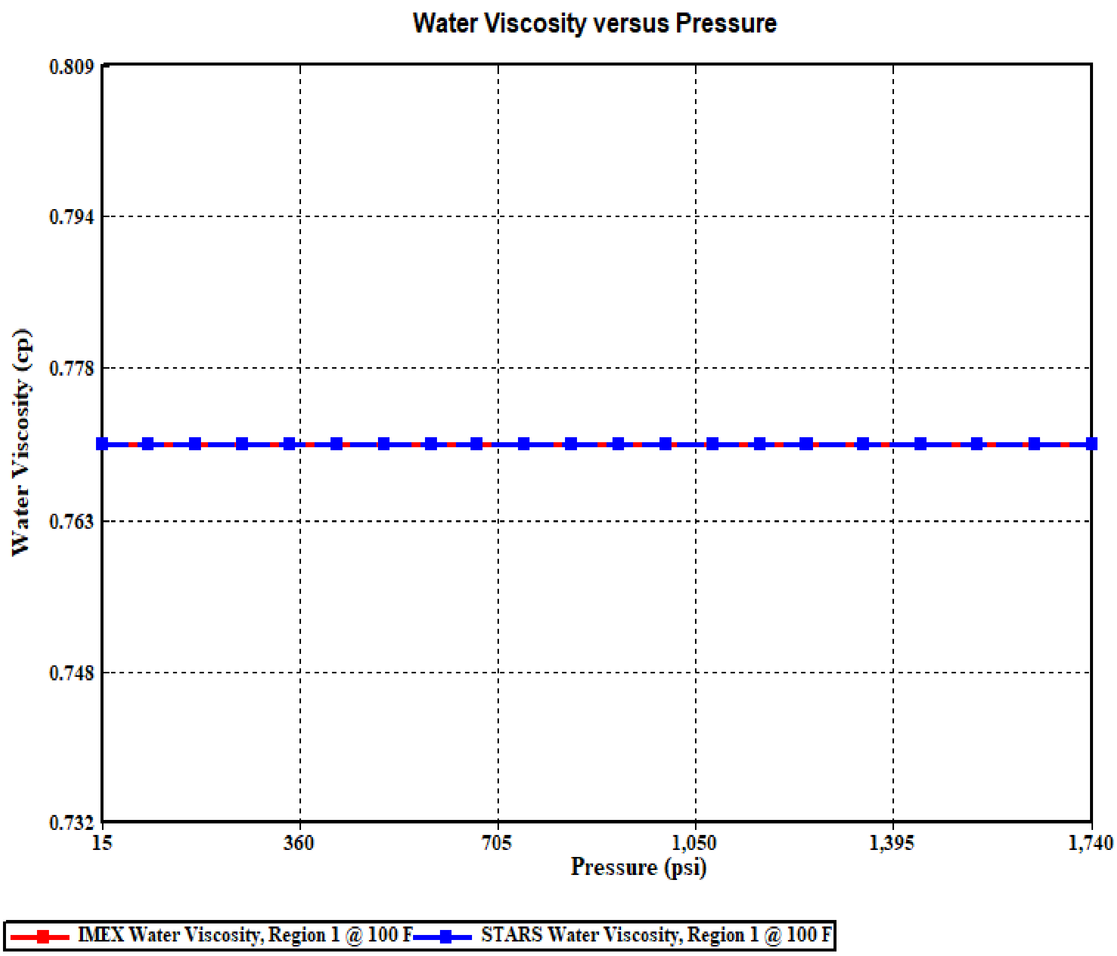

Figure 3.8. *Water viscosity versus pressure (at reservoir temperature).*

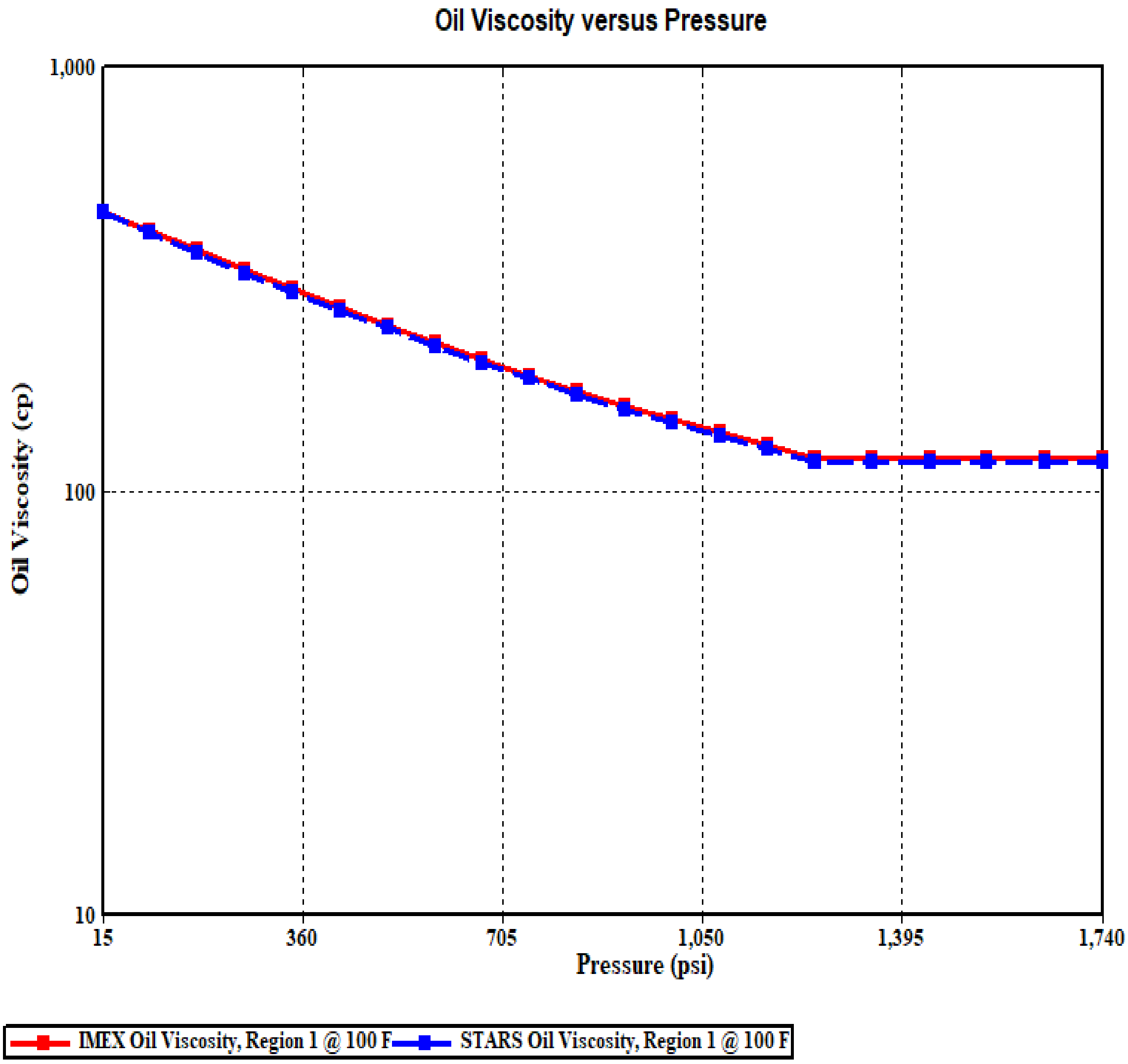

Figure 3.9. *Oil viscosity versus pressure (at reservoir temperature).*

Understanding these relationships enables accurate reservoir characterization, optimized production strategies, and improved decision-making in the oil production domain. These findings contribute to the enhancement of oil recovery techniques, maximizing reservoir productivity, and ultimately leading to more efficient and sustainable oil production operations.

Rock Fluid Interaction Data

Throughout the rock fluid simulation process, a new rock type was developed, and a correlation was utilized to generate the relative permeability table for both the gas-oil system and the water-oil system. The data derived from these correlations are summarized in Table 3.4 and will be employed to graphically represent the relative permeability curves of water and oil against water saturation in Figure 3.10, as well as the relative permeability curve of oil versus gas against liquid saturation in Figure 3.11.

Table 3.4. *Rock fluid properties.*

Properties	**Values**
Residual Oil for Water-oil Table SORW, fraction	0..3
Residual Oil for Gas-liquid Table SORG, fraction	0.3
Critical Water Saturation SWCRIT, fraction	0.2
Critical Gas Saturation SGCRIT, fraction	0.05

As aforementioned, it must be noted that each of this methods possesses its own set of distinct advantages and disadvantages, and their appropriateness is contingent upon the specific circumstances of the situation. To determine the applicability of these methods, various outputs were analyzed, including:

- Cumulative Oil
- Cumulative Water Oil Ratio
- Production Rate
- Injection Rate
- Injection Pressure

The phase properties and molecular weight of the components injected into the reservoir are summarized in Table 3.5.

Table 3.5. *Components and phase properties.*

Component	**Reference Phase**	**Molecular Weight (lb./mole)**
Polymer	Aqueous	8000
Surfactants	Aqueous	299.41
Carbon dioxide	Gaseous	12.66

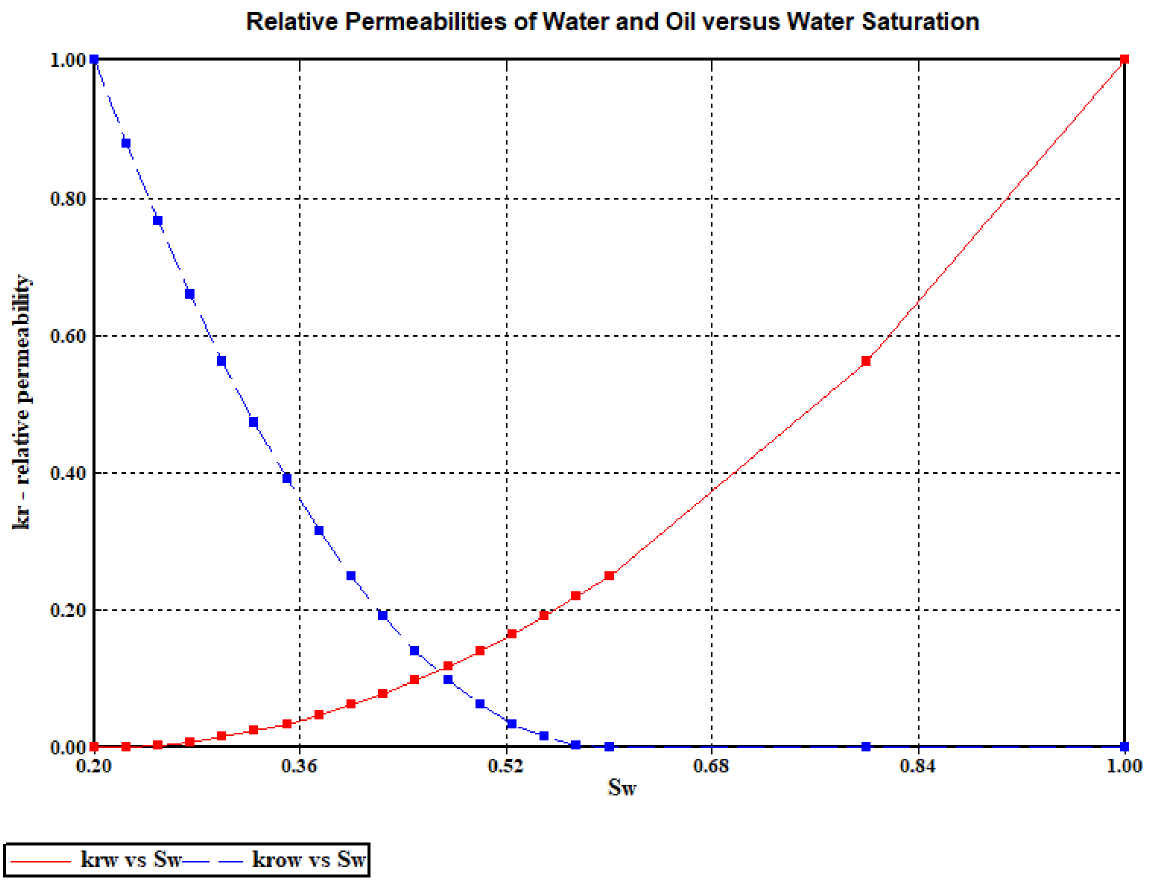

Figure 3.10. *Relative permeabilities of oil and water versus water saturation.*

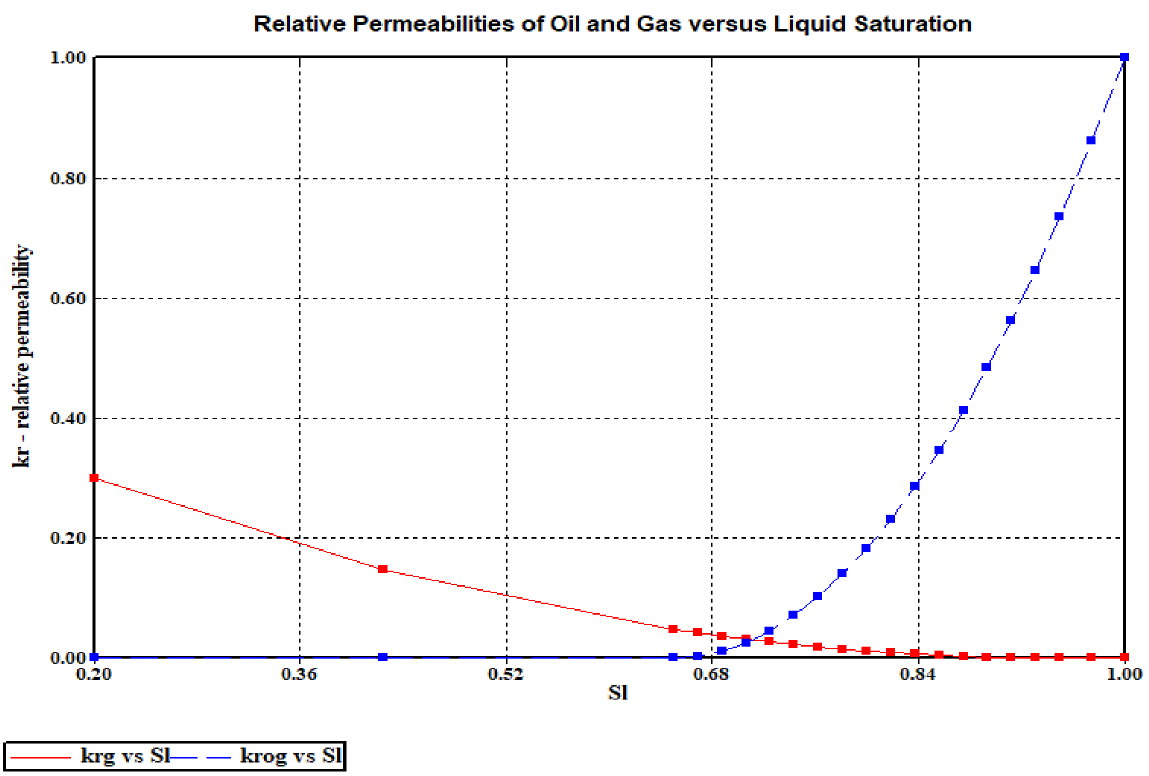

Figure 3.11. *Relative permeabilities of gas and oil versus liquid saturation.*

CHAPTER IV

Results and Discussion

The purpose of this chapter is to present the outcomes and analysis of a study aimed at evaluating various non-thermal enhanced oil recovery (EOR) methods, including polymer injection, carbon dioxide injection, and foam injection. The results are structured according to the research questions and hypotheses that were formulated in Chapter 1.

Polymer Injection

This technique has been successfully employed in numerous oil fields worldwide resulting in significant improvements in oil recovery rates. Injected polymer helps to develop the mobility ratio by increasing the viscosity of the injected water. Potential for good oil recovery in conventional alkaline flooding is higher in crudes that are viscous, naphthenic, and low API. The maximum viscosity for alkaline flooding is <200 cp. The minimum average permeability should be> 20 md. Sandstone is preferred because carbonates may contain anhydrites which reacts to the alkaline.

Optimization of Polymer Injection rates

To evaluate the effects of changing the injection rate of aqueous polymer, we compared two different injection rates 1000 bbl and 1500 bbl Figure 4.1 shows the cumulative oil graph, while Figure 4.2 displays the amount of oil recovered during these 3 years and Figure 4.3 shows the cumulative water-to-oil ratio. Upon reviewing the outcomes presented in Table 4.1, 1500 bbl is the option with the most cumulative oil or the most recoverable oil, so we took 1500 bbl to be maximum injection rate.

Table 4.1. *Different rates of surface aqueous polymer injection (1000 bbl and 1500 bbl) using 1000 psi of minimum bottom hole pressure.*

	CO (bbl)	**RF (%)**	**CWOR**	**OR-(bbl/day)**
Polymer , 1000 bbl	1,032,790	29.2	0	943.2
Polymer , 1500 bbl	1,532,090	43.3	4.9e-004	1,399.2

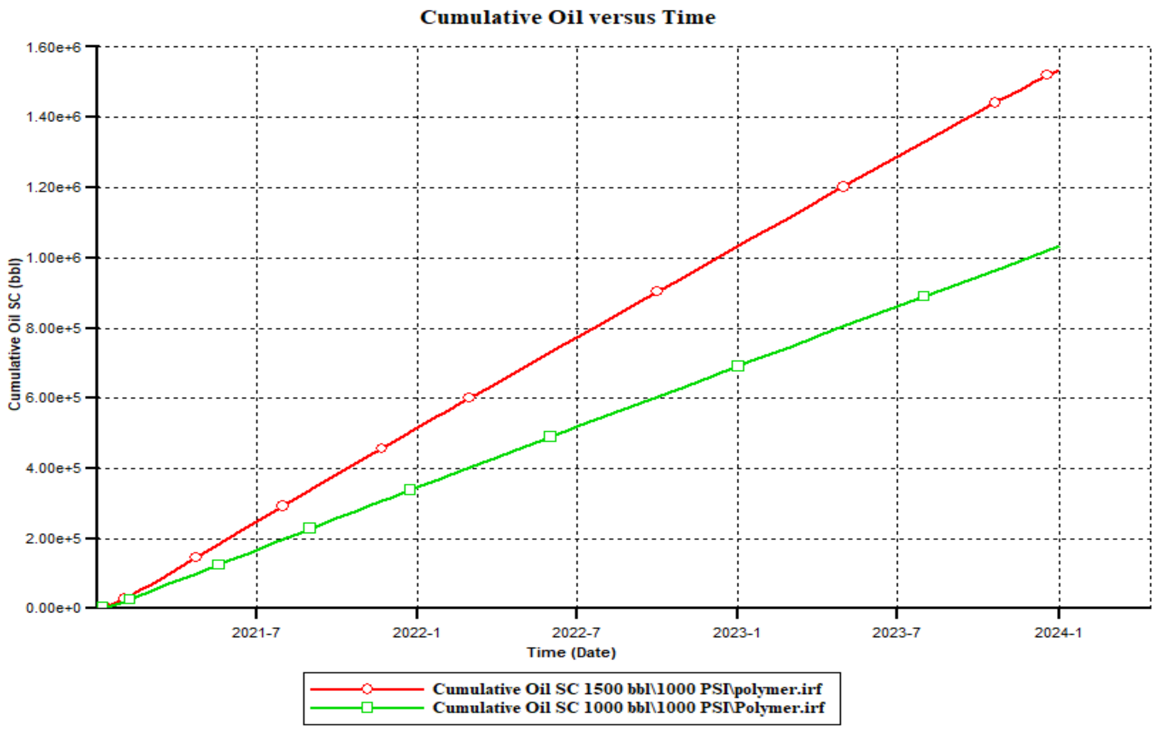

Figure 4.1. *Cumulative oil versus time for different rates of surface aqueous polymer injection (1000 bbl and 1500 bbl) using 1000 psi of minimum bottom hole pressure.*

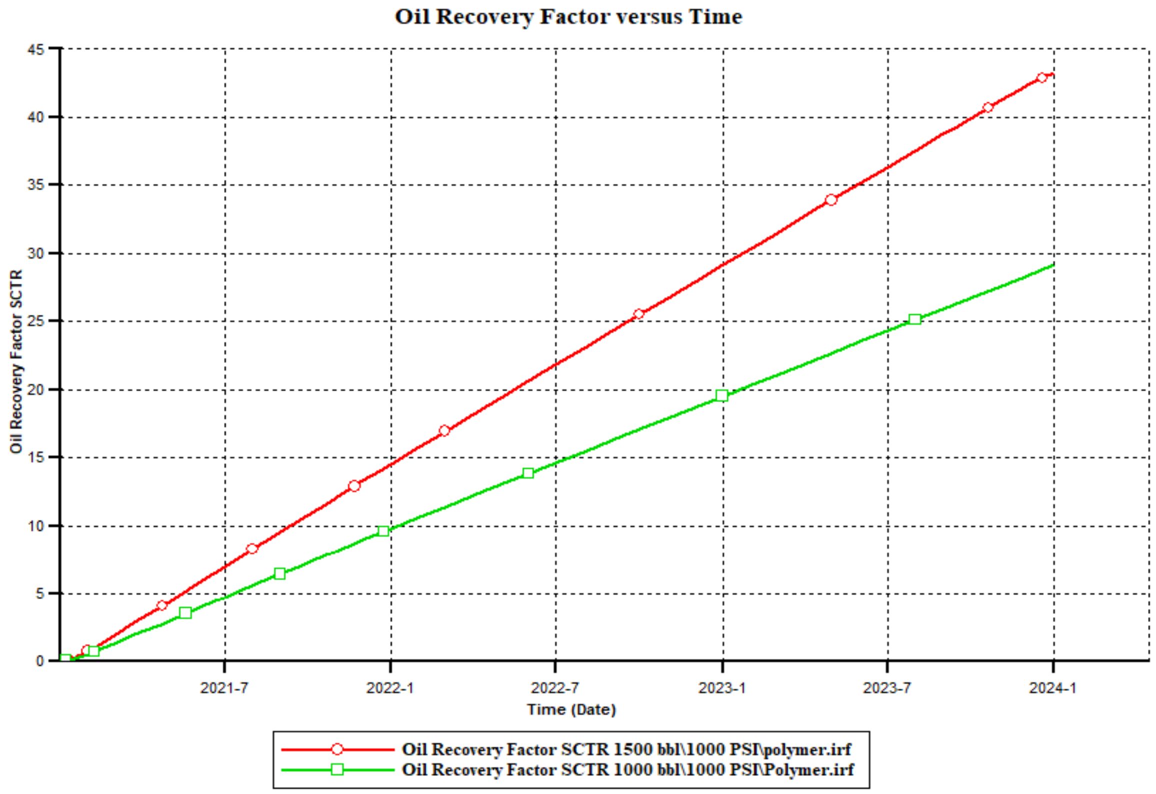

Figure 4.2. *Oil recovery factor versus time for different rates of surface aqueous polymer injection (1000 bbl and 1500 bb) using 1000 psi of minimum bottom hole pressure.*

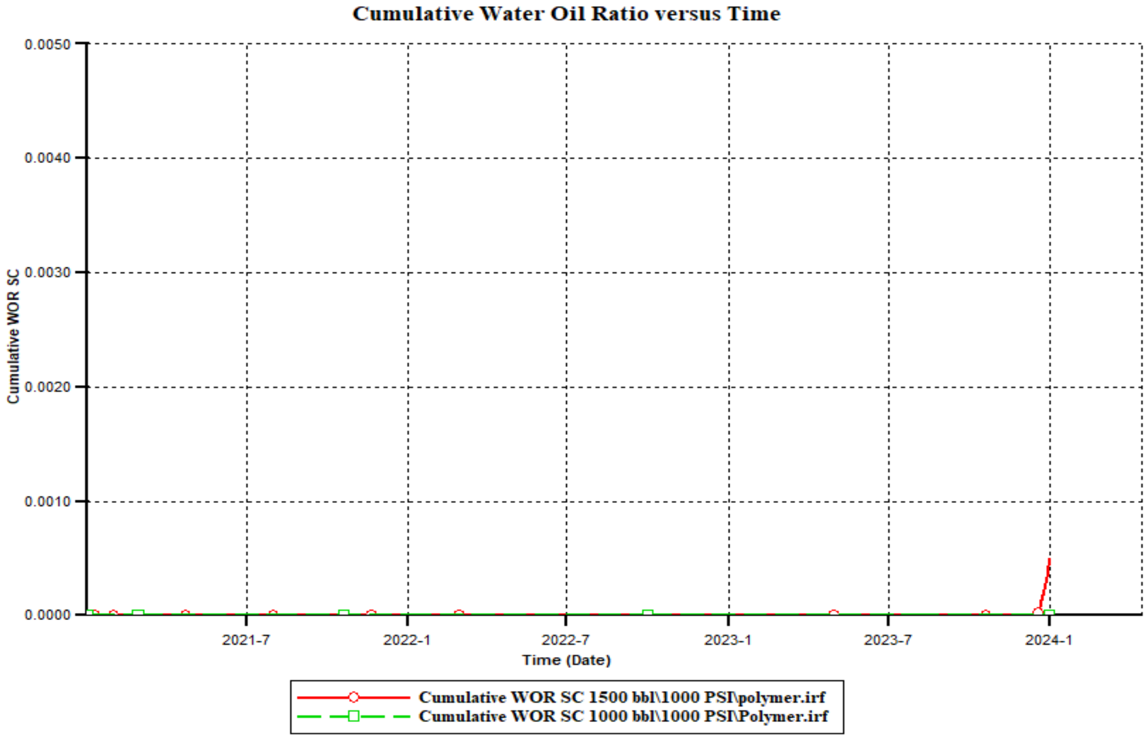

Figure 4.3. *Cumulative water oil ratio versus time for different rates of surface aqueous polymer injection (1000 bbl and 1500 bbl) using 1000 psi of minimum bottom hole pressure.*

Optimization of Minimum Bottom Hole Pressure

After selecting the rate of injection, the next step is to evaluate the effects of changing the applied minimum bottom hole pressure, 1000 psi and 1500 psi are the two options that are compared, where Figure 4.4 displays the cumulative oil graph and Figure 4.5 shows the amount of oil that recovered during these 3 years while Figure 4.6 displays cumulative water oil ratio. Based on a comprehensive analysis of the results delineated in Table 4.2, 1000 psi option yields the highest cumulative oil or highest recoverable amount of oil also it has a less cumulative water oil ratio less than the other option so we selected 1000 psi.

Table 4.2. *Different applied minimum bottom hole pressure (1000 psi, and 1500 psi) using 1500 bbl of surface aqueous polymer injection.*

	CO (bbl)	**RF (%)**	**CWOR**	**OR-(bbl/day)**
Polymer , 1000 psi	1,532,090	43.3	4.9e-004	1,399.2
Polymer , 1500 psi	1,290,790	36.4	0	1178.8

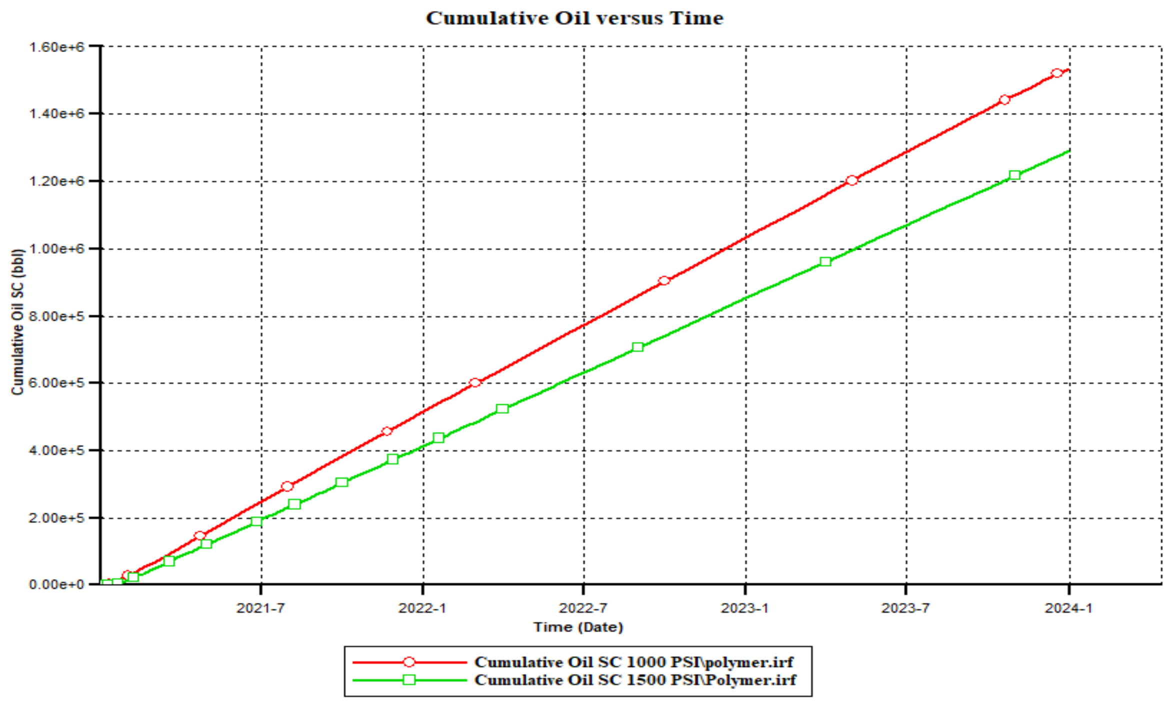

Figure 4.4. *Cumulative oil versus time for different applied minimum bottom hole pressure (1000 psi, and 1500 psi) using 1500 bbl of surface aqueous polymer injection.*

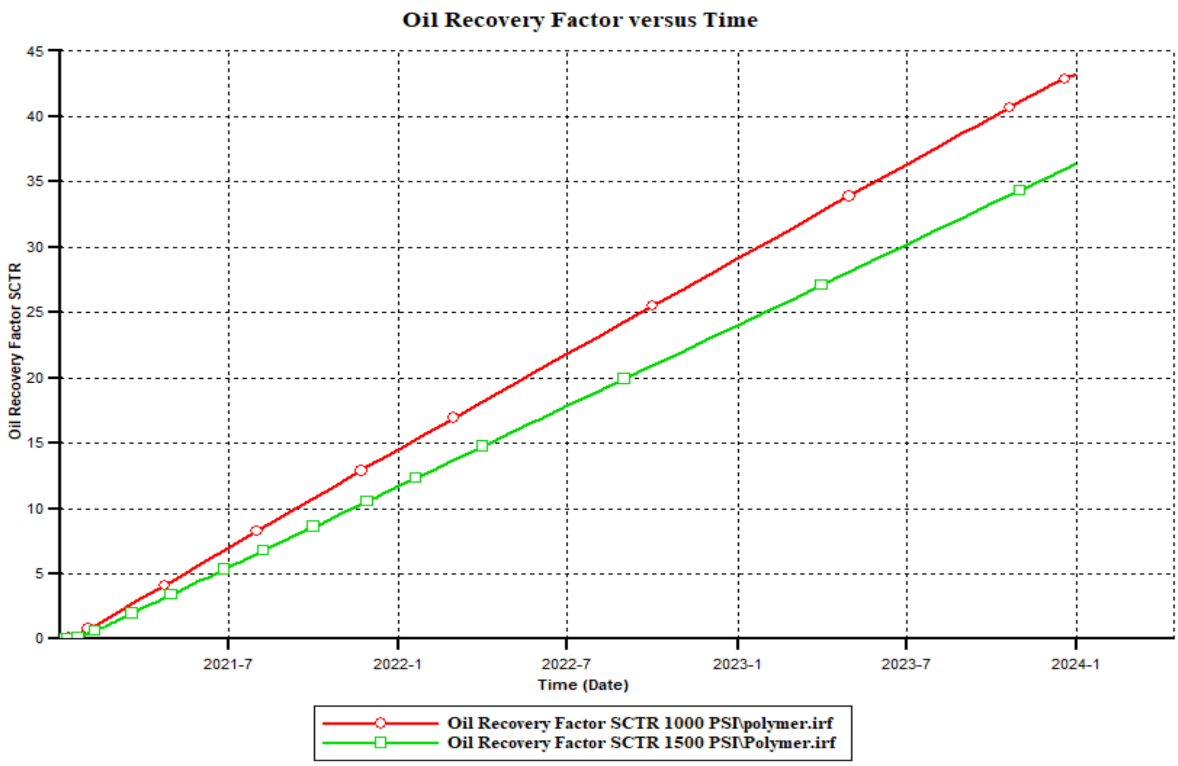

Figure 4.5. *Oil recovery factor versus time for different applied minimum bottom hole pressure (1000 psi, and 1500 psi) using 1500 bbl of surface aqueous polymer injection.*

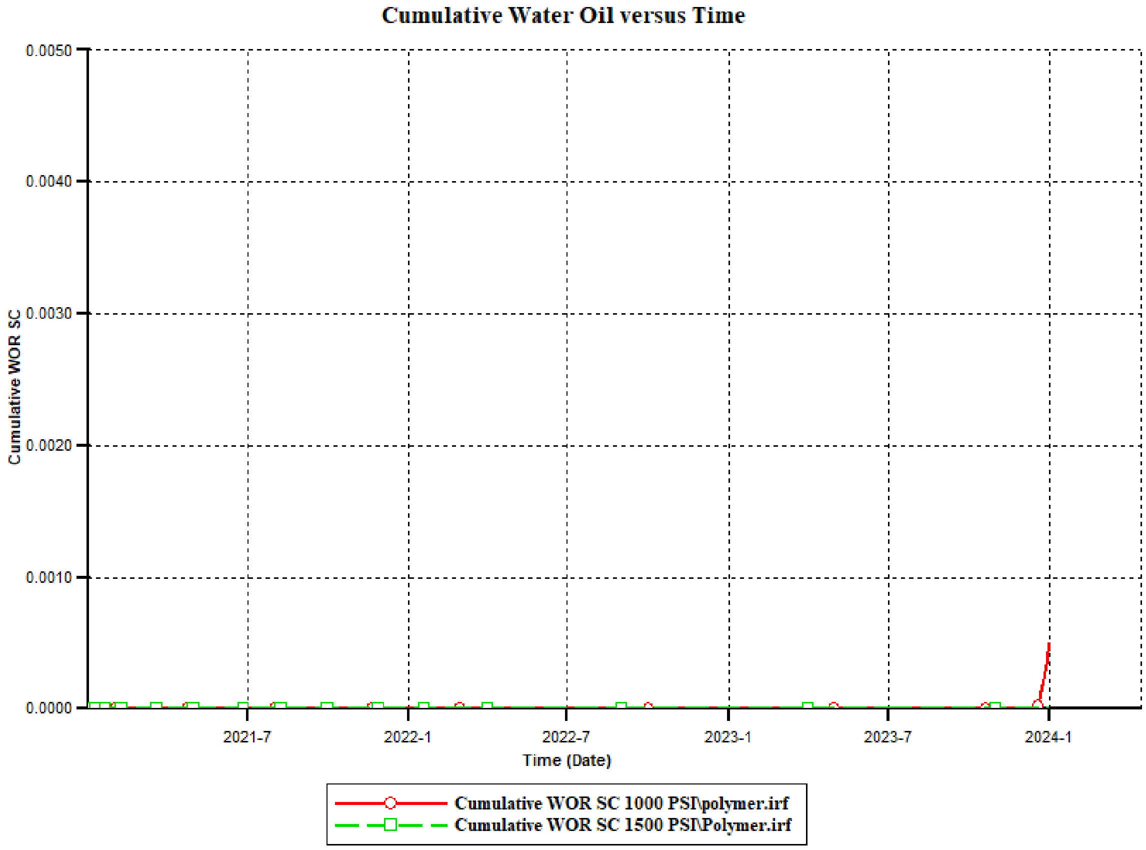

Figure 4.6. *Cumulative water oil ratio versus time for different applied minimum bottom hole pressure (1000 psi, and 1500 psi) using 1500 bbl of surface aqueous polymer injection.*

Carbon Dioxide Injection

The success of this technique depends on various factors including the reservoir's geology, the quality of the injected CO_2, properties of depleted oil and the availability of infrastructure to capture and transport CO_2.

Firstly, the reservoir's geology plays a critical role in the success of CO_2 injection. The reservoir's rock type, permeability, and porosity determine how well the injected CO_2 can move through the rock and displace the remaining oil. The injection pressure and rate must also be optimized to ensure that the CO_2 can penetrate the reservoir's various layers effectively.

Secondly, the quality of the injected CO_2 is essential for effective EOR, CO_2 must meet certain quality standards to be suitable for injection. For instance, it must be pure, dry, and free of contaminants that could damage the reservoir or affect the oil's composition. The temperature and pressure of the injected CO_2 must also be carefully controlled to ensure maximum oil recovery.

Finally, the properties of the depleted oil are crucial to the success of CO_2 injection. Heavy crude oil or oil with high viscosity can benefit significantly from CO_2 injection.

Optimization of Carbon Dioxide Injection rates

The initial step in this method entails evaluating the impact of varying the CO2 injection rate. To accomplish this, two different injection rate options (1000 scf and 1500 scf) have been compared and analyzed. The results are presented in Figures 4.7, Figure 4.8, and Figure 4.9. Figure 4.7 shows the cumulative oil graph, and Figure 4.8 shows the percentage of oil recovered over 3 years period, while Figure 4.9 displays the cumulative water-oil ratio. Upon reviewing the outcomes presented Table 4.3, 1500 scf option yields the highest cumulative oil and recoverable amount of oil, and has also cumulative water-oil ratio less than 0.01.

Table 4.3. *Different rates of surface CO_2 injection (1000 scf and 1500 scf) using 1000 psi of minimum bottom hole pressure.*

	CO (bbl)	**RF (%)**	**CWOR**	**OR-(bbl/day)**
CO_2 , 1000 scf	1,009,760	28.5	0.002	922.2
CO_2, 1500 scf	1,215,340	34.3	0.005	1,110

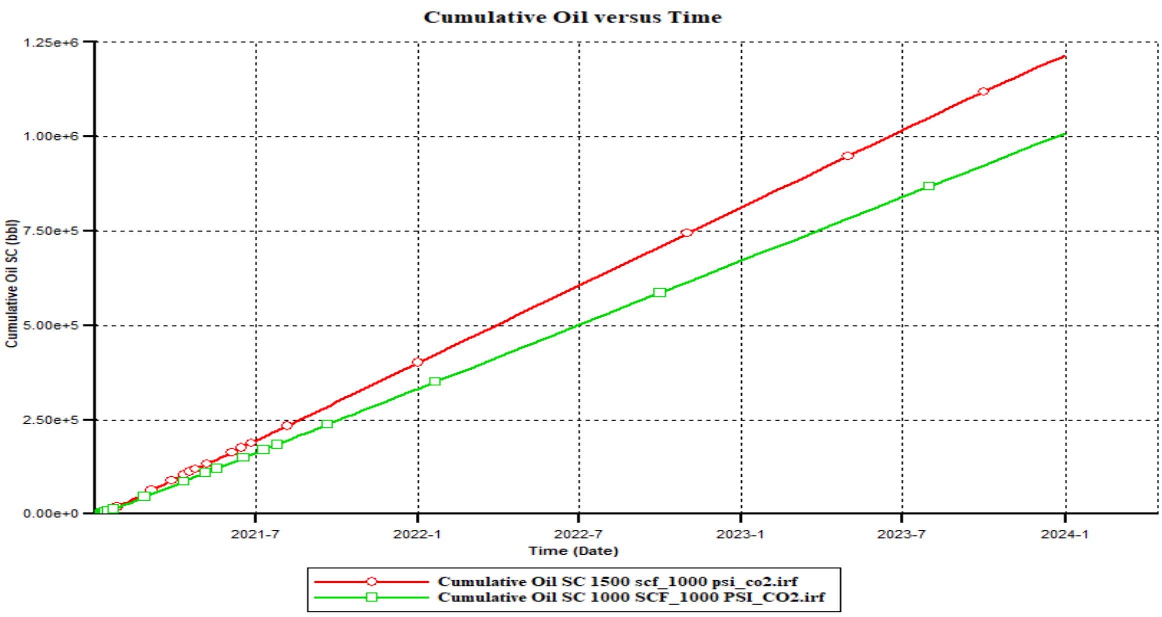

Figure 4.7. *Cumulative oil versus time for different rates of surface CO_2 injection (1000 scf and 1500 scf) using 1000 psi of minimum bottom hole pressure.*

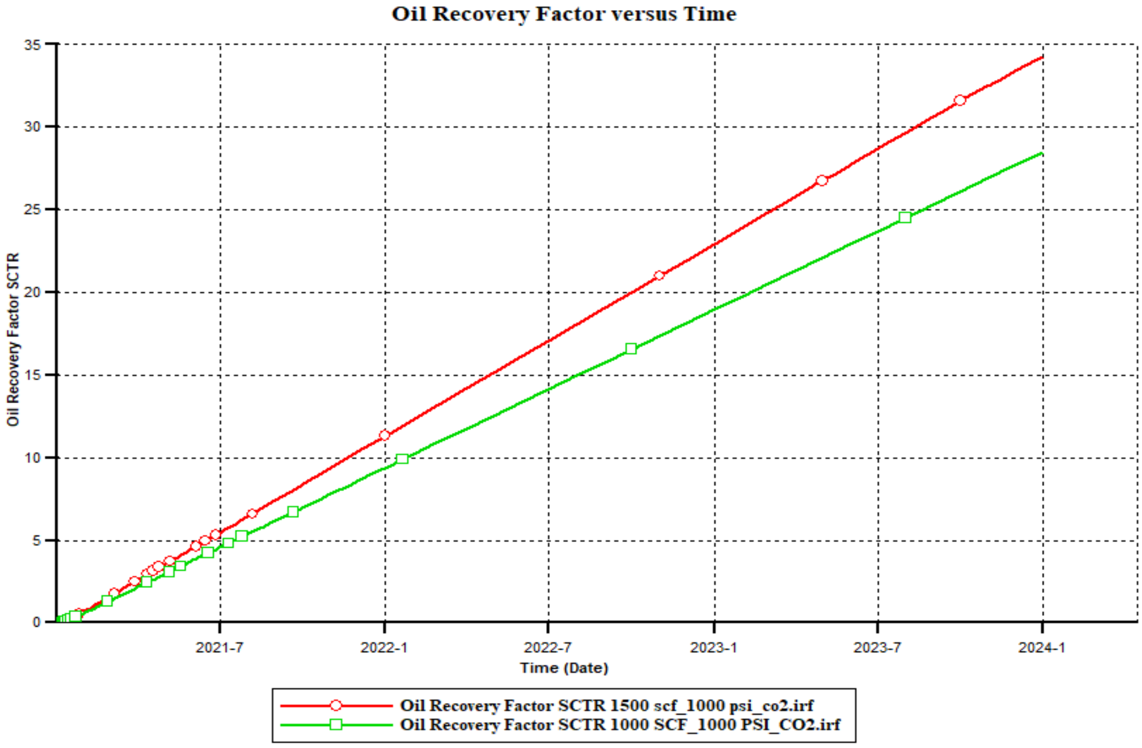

Figure 4.8. *Oil recovery factor versus time for different rates of surface CO_2 injection (1000 scf and 1500 scf) using 1000 psi of minimum bottom hole pressure.*

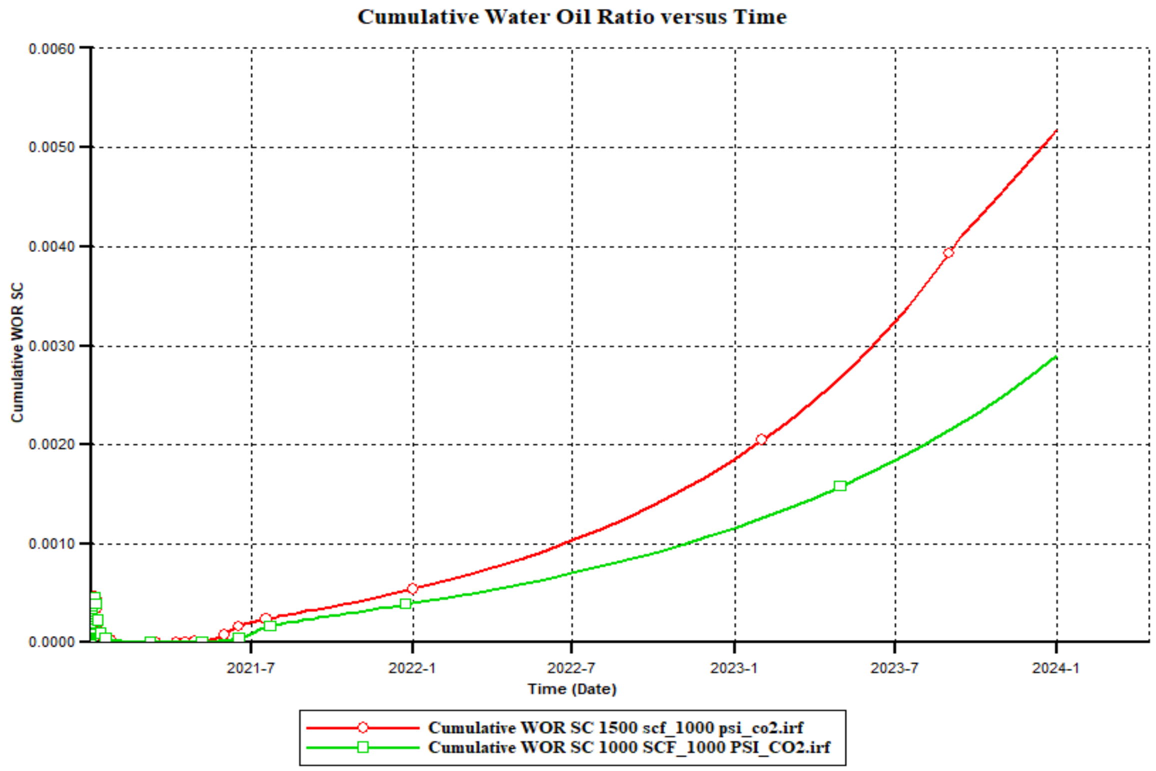

Figure 4.9. *Cumulative water oil ratio versus time for different rates of surface CO_2 injection (1000 scf and 1500 scf) using 1000 psi of minimum bottom hole pressure.*

Optimization of Minimum bottom Hole Pressure

Similar to polymer injection method, upon selecting the CO_2injection rate, the subsequent step involves evaluating the impact of varying the applied minimum bottom hole pressure. Two options (1500 psi, and 1000 psi) have been compared in this regard. The results are presented in Figures 4.10, 4.11, and 4.12. Figure 4.10 shows the cumulative oil graph, and Figure 4.11 shows the percentage of oil recovered over a 3 years period, while Figure 4.12 shows the cumulative water-oil ratio. Based on a comprehensive analysis of the results delineated in Table 4.4, the option of maintaining a pressure of 1000 psi yields the highest cumulative oil and recoverable amount of oil. Furthermore, this option exhibits a cumulative water-oil ratio that is less than 0.01.

Table 4.4. *Different applied minimum bottom hole pressure (1000 psi, and 1500 psi) using 1500 scf of surface CO_2 injection.*

	CO (bbl)	**RF (%)**	**CWOR**	**OR-(bbl/day)**
CO_2 , 1000 psi	1,215,340	34.3	0.005	1,110
CO_2 , 1500 psi	1,110,520	31.3	0.003	1014.2

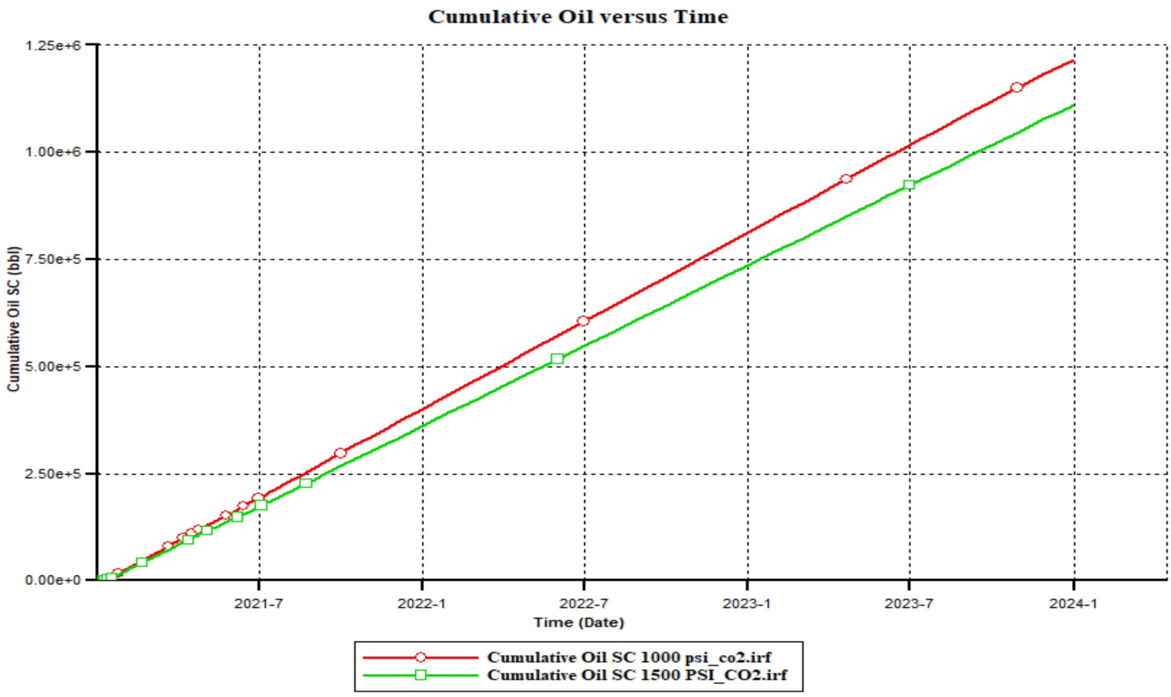

Figure 4. 10. *Cumulative oil versus time of different applied minimum bottom hole pressure (1500 psi, and 1000 psi) using 1500 scf rate of surface CO_2 injection.*

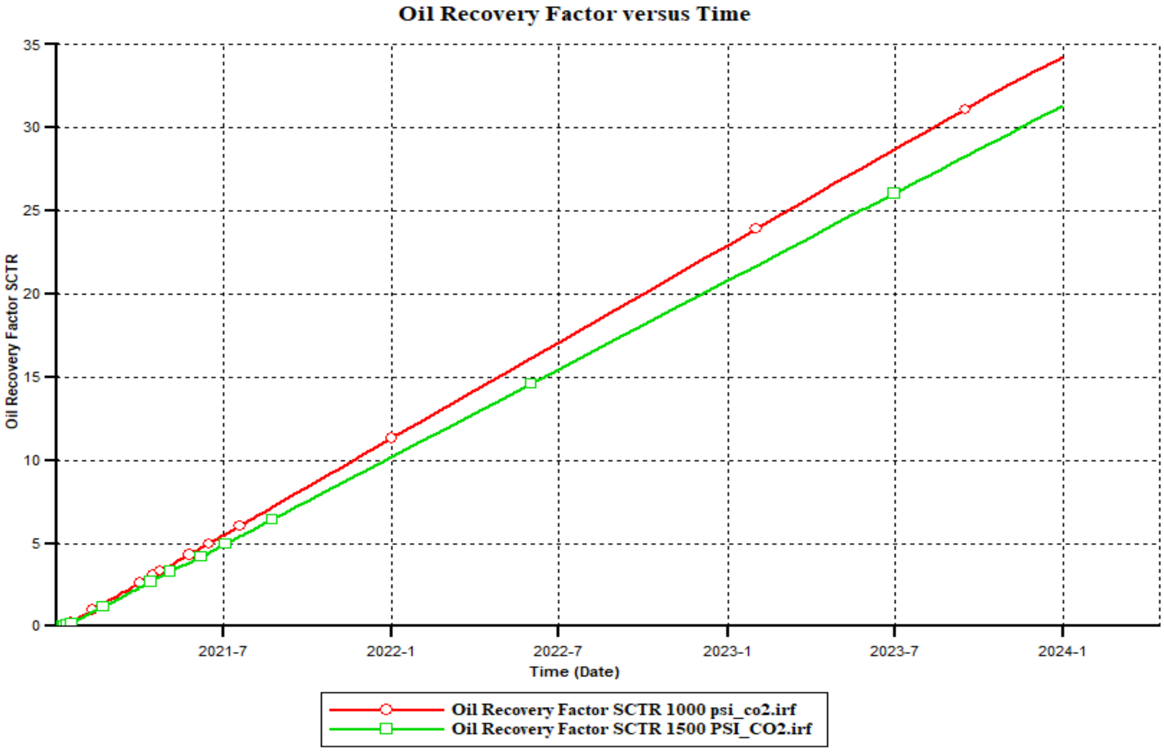

Figure 4.11. *Oil recovery versus time of different applied minimum bottom hole pressure (1500 psi, and 1000 psi) using 1500 scf rate of surface CO_2 injection.*

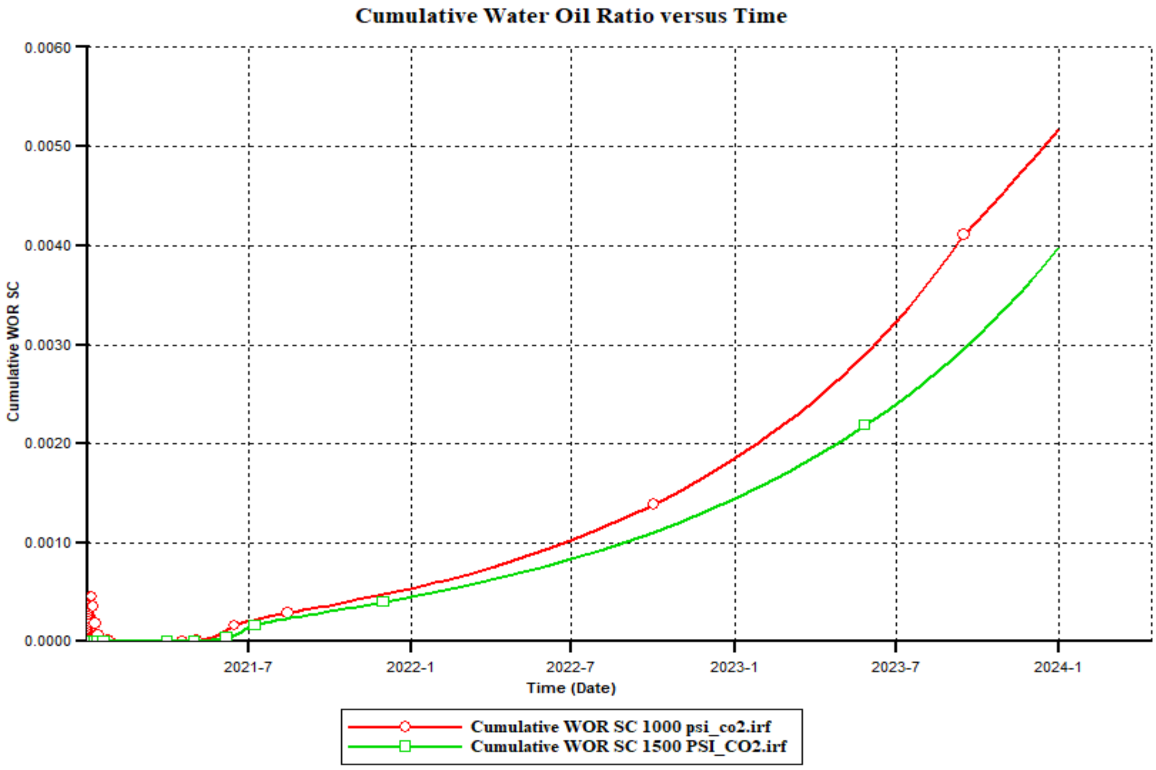

Figure 4.12. *Cumulative water oil ratio versus time for different applied minimum bottom hole pressure (1000 psi, and 1500 psi) using 1500 scf of surface CO_2 injection.*

Foam Injection

Foam injection involves injecting a mixture of gas and liquid surfactants into the reservoir, which then creates a foam that helps mobilize trapped oil. The foam reduces the mobility of the injected gas, diverting it to unswept areas of the reservoir, and improving the sweep efficiency. Foam injection is most effective in high-permeability reservoirs, where the foam can efficiently displace the remaining oil.

When foam is injected into an oil reservoir, it creates a network of gas bubbles within the oil. This network of bubbles has a high surface area and creates a highly interconnected pore structure, which increases the contact area between the oil and the injected fluid. This increased contact area, in turn, reduces. As the foam displaces the oil, it reduces the mobility of the injected gas, causing it to divert to unswept areas of the reservoir, improving the sweep efficiency.

The foam also helps to reduce the amount of water that enters the production wells, preventing early breakthrough of water and increasing oil recovery. Furthermore the foam can help to control reservoir heterogeneity by diverting the injected fluid to the less-permeable parts of the reservoir, which can result in more efficient oil recovery.

Optimization of Foam Injection Rates

In order to examine the impact of altering the rate of foam injection, two different injection rate options were compared, 1000 bbl and 1500 bbl Figure 4.13 displays a cumulative oil graph, and Figure 4.14 shows the percentage oil recovered over a 3 years period, while Figure 4.15 shows a cumulative water-to-oil ratio. Upon reviewing the outcomes presented Table 4.5, 1500 bbl option yields in the highest cumulative oil production and also yields a zero CWOR.

Table 4.5. *Different rates of surface aqueous foam injection (1000 bbl and 1500 bbl) using 1000 psi of minimum bottom hole pressure.*

	CO (bbl)	**RF (%)**	**CWOR**	**OR-(bbl/day)**
Foam , 1000 bbl	1,006,190	28.4	0	918.9
Foam , 1500 bbl	1,275,270	36	0	1,164.6

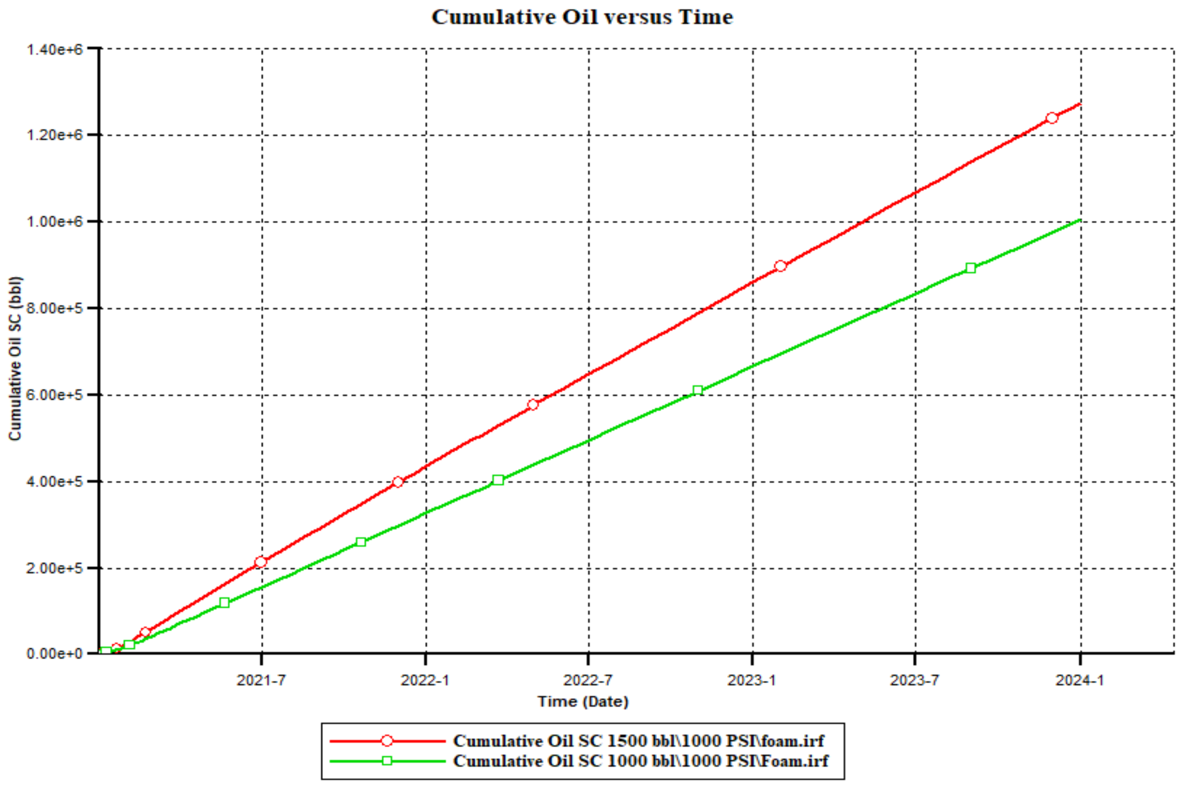

Figure 4.13. *Cumulative oil versus time of different rates for surface aqueous foam injection (1000 bbl and 1500 bbl) using 1000 psi of minimum bottom hole pressure.*

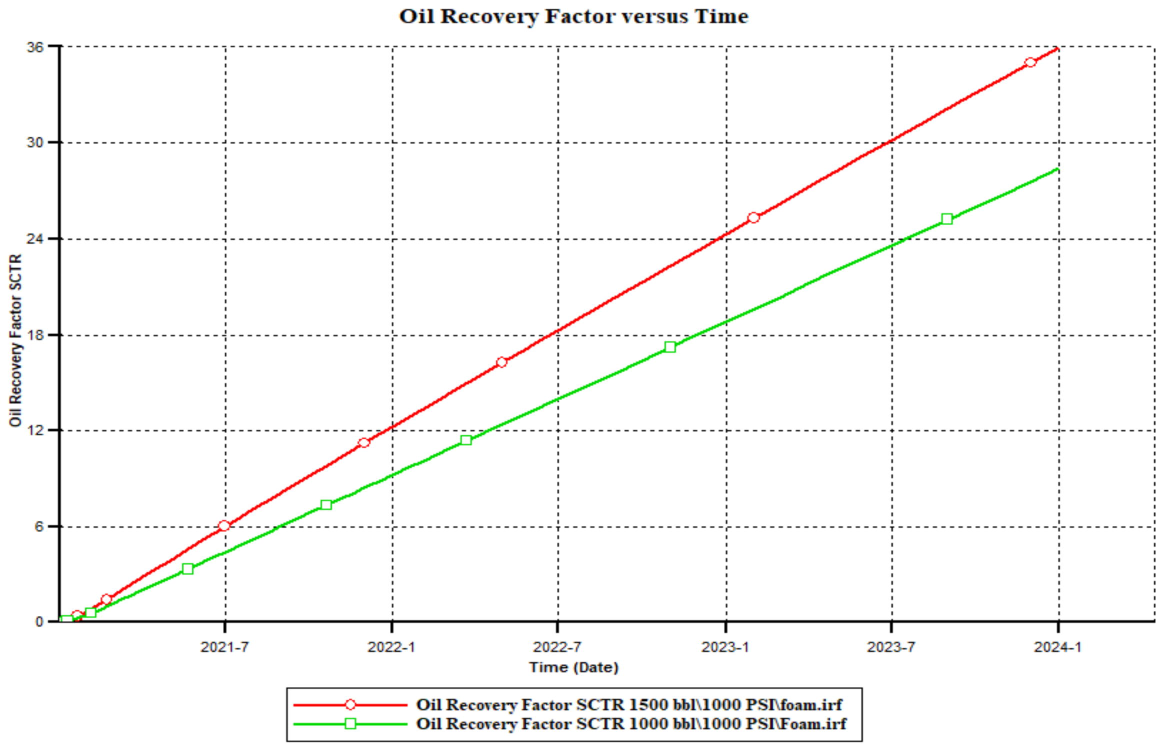

Figure 4.14. *Oil recovery factor versus time for different rates of surface aqueous foam injection (1000bb. and 1500 bbl) using 1000 psi of minimum bottom hole pressure.*

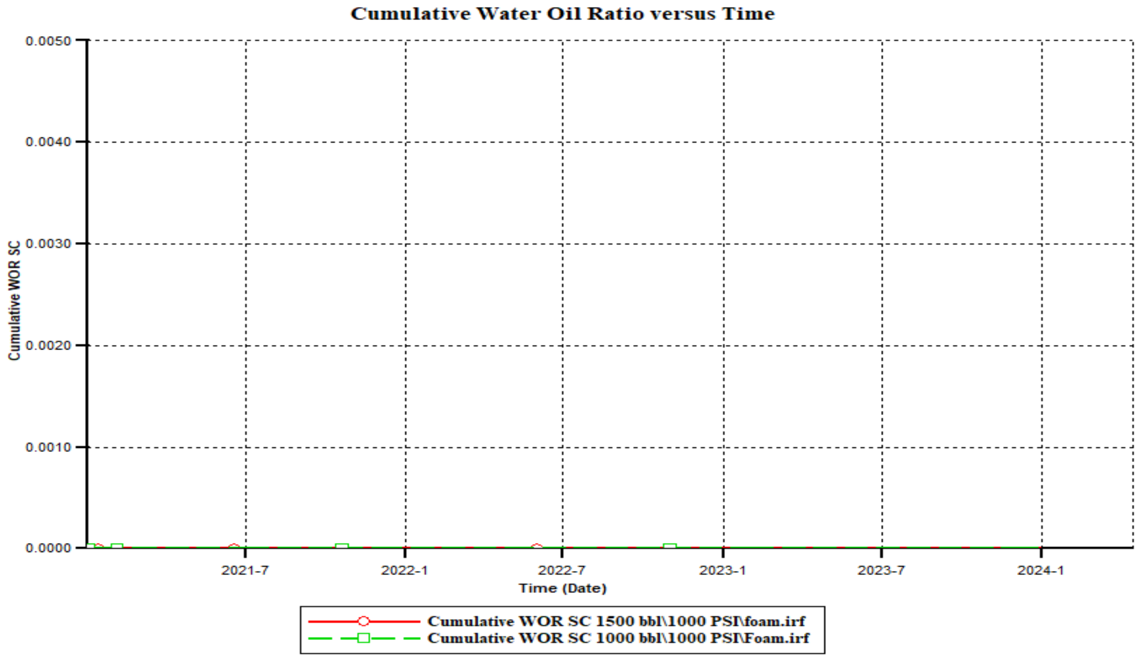

Figure 4.15. *Cumulative water oil ratio versus time of different rates of surface aqueous foam injection (1000 bbl and 1500 bbl) using 1500 psi of minimum bottom hole pressure.*

Optimization of Minimum Bottom Hole Pressure

After determining the injection rate for foam, the subsequent step involves assessing the impact of varying the minimum bottom hole pressure, which can be set to two different values of 1000 psi, and 1500 psi. These variations are compared in Figures 4.16 and 4.17, which show the cumulative oil and the percentage of oil recovered over a period of 3 years, respectively. Additionally, Figure 4.18 demonstrates the cumulative water-oil ratio. Based on a outcomes delineated in Table 4.6, It is evident that the option with a minimum bottom hole pressure of 1000 psi results in the highest cumulative oil production and recoverable amount of oil, while also having a zero cumulative water-oil ratio.

Table 4. 6. *Different applied minimum bottom hole pressure (1000 psi and 1500 psi) using 1500 bbl of surface aqueous foam injection.*

	CO (bbl)	**RF (%)**	**CWOR**	**OR-(bbl/day)**
Foam , 1500 psi	1,149,910	32.5	0	1,150.2
Foam , 1000 psi	1,275,270	36	0	1,164.6

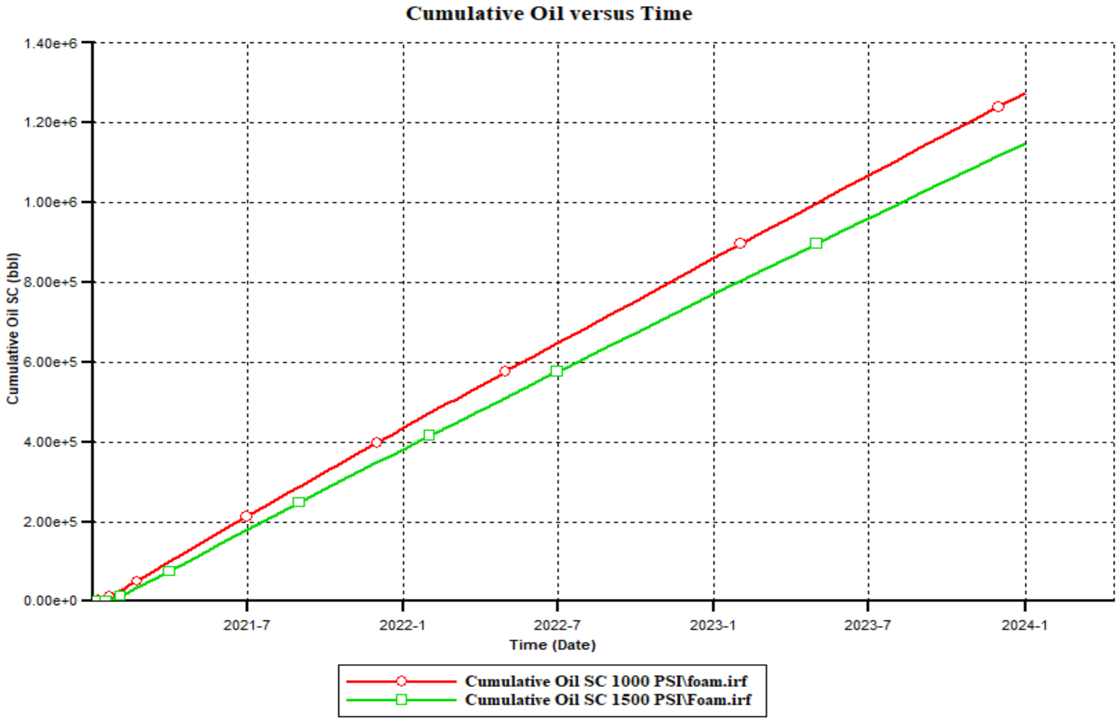

Figure 4.16. *Cumulative oil versus time for different applied minimum bottom hole pressure (1500 psi, and 1000 psi) using 1500 bbl of surface aqueous foam injection.*

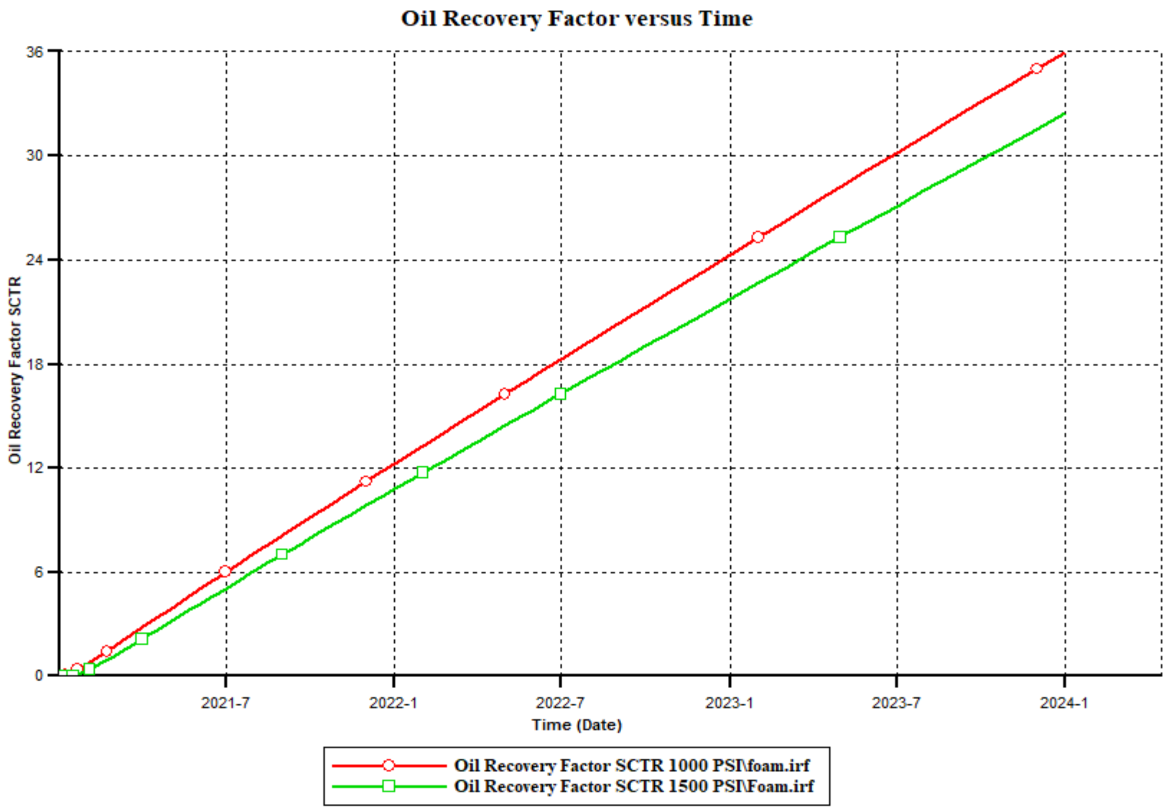

Figure 4.17. *Oil recovery factor versus time for different applied minimum bottom hole pressure (1500 psi and 1000 psi) using 1500 bbl of surface aqueous foam injection.*

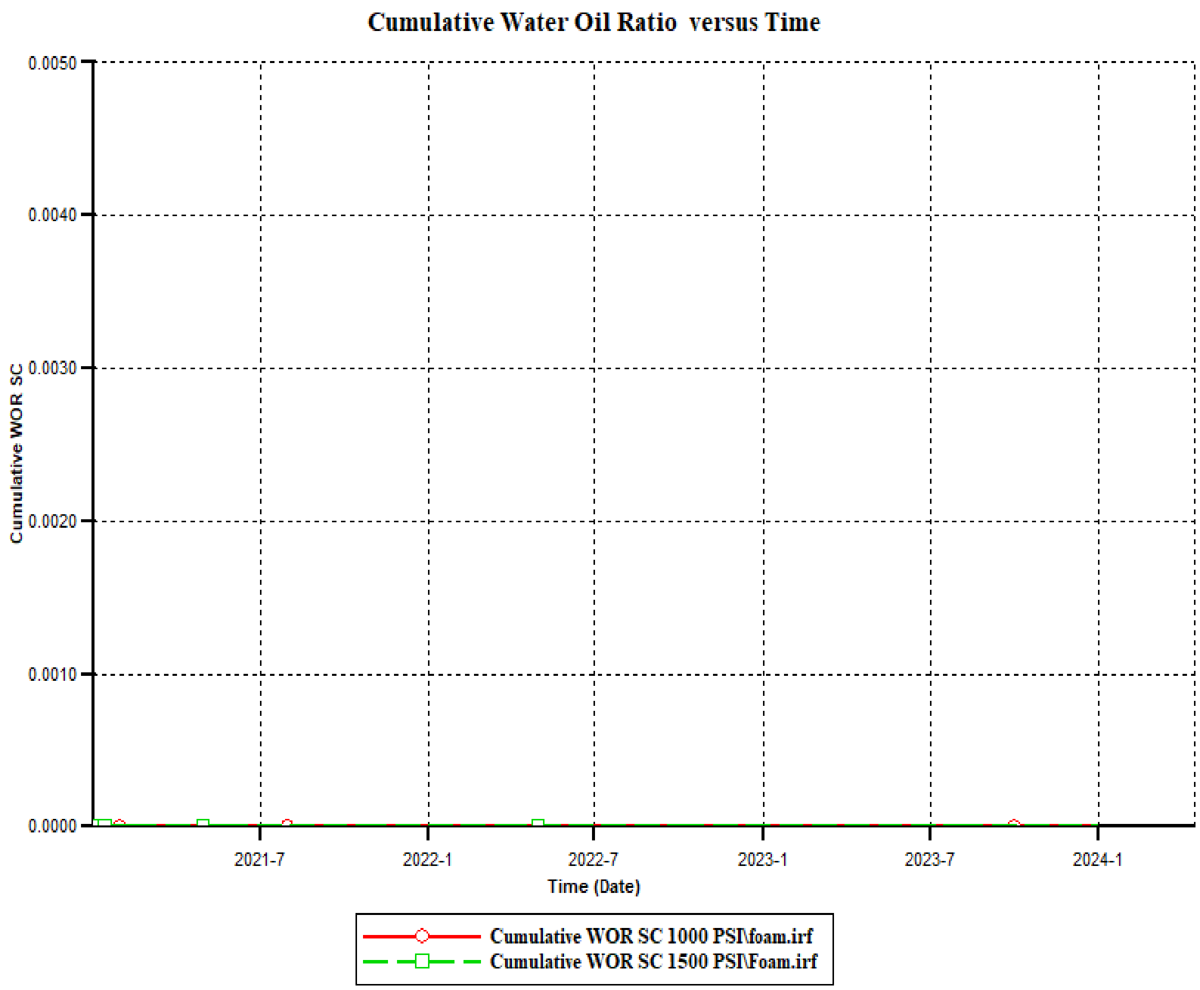

Figure 4.18. *Cumulative water oil ratio versus time for different applied minimum bottom hole pressure (1000 psi and 1500 psi) using 1500 bbl of surface aqueous foam injection.*

Discussion

Each of this methods (polymer injection, foam injection, and carbon dioxide injection) can be effective for heavy oil production depending on the specific reservoir and operating conditions. However some factors that can influence the effectiveness of each method.

Polymer injection can improve oil recovery by increasing the viscosity of the injected water, which helps to push oil towards the producing wells. This method is most effective in reservoirs with high permeability contrasts or where gravity segregation is significant. However, the effectiveness of polymer injection can be limited by the polymer's stability, compatibility with the reservoir rock and potential for polymer adsorption or precipitation.

Foam injection can improve oil recovery by reducing the mobility of the injected gas, which helps to divert it into unswept areas of the reservoir. This method is most effective in reservoirs with high permeability contrasts or where reservoir heterogeneity leads to channeling or bypassing of injected fluids however the effectiveness of foam injection can be limited by the foam stability, surfactant adsorption, and the presence of high salinity or divalent ions in the reservoir brine.

Carbon dioxide injection can improve oil recovery by several mechanisms, including viscosity reduction, gas swelling and solubilization of heavy oil components. This method is most effective in reservoirs with favorable fluid properties (e.g high oil saturation, low interfacial tension) and where the reservoir rock has good injectivity and limited water saturation. However, the effectiveness of carbon dioxide injection can be limited by the availability and cost of CO_2, potential for CO_2 leakage, and the risk of reservoir damage or fracturing.

According to the outcomes derived from the model analysis, it is unequivocally evident that the polymer injection method outperforms the other two methods in terms of production rate. The data presented in Figure 5.1 clearly illustrates the cumulative oil, while Figure 5.2 depicts the oil recovery factor for each method. Notably, the polymer injection method exhibited an impressive production rate of 1,399.2 barrels per day, surpassing the production rates achieved by the alternative approaches. In comparison, the foam injection method yielded a daily recovery of 1,164.6 barrels, and the carbon dioxide injection method exhibited the least productive rate of 1,110 barrels per day.

However, if we consider Figure 5.3, which outlines the cumulative water oil ratio. Remarkably, the CO_2 injection method yields the highest value of 0.005, followed closely by the polymer injection method with a value of 4.9e-004. In contrast, the foam injection method demonstrated a cumulative water oil ratio of zero. A higher cumulative water oil ratio signifies that the reservoir is generating a substantial amount of water, which poses challenges to the recovery of oil. Consequently, additional investments in enhanced oil recovery techniques may be necessary to address this issue. Conversely, a lower cumulative water oil ratio indicates that the well is producing a greater amount of oil relative to the water being produced. This finding suggests favorable reservoir quality or effective well management strategies.

In conclusion, based on the comprehensive analysis conducted using this model, the polymer injection method emerges as the most effective approach in terms of cumulative oil and its negligible cumulative water oil ratio. The foam injection method follows closely behind in terms of effectiveness, while the carbon dioxide injection method exhibits the least favorable results. These findings presented in Table 5.1, highlight the superiority of the polymer injection method and emphasize the potential benefits of employing it in oil production operations.

Table 5. 1. *Summarized result of reservoir model.*

	CO (bbl)	**RF (%)**	**CWOR**	**OR-(bbl/day)**
Polymer	1,532,090	43.3	4.9e-004	1,399.2
CO_2	1,215,340	34.3	0.005	1,110
Foam	1,275,270	36	0	1,164.6
Non injection	397,984.9	2.7	4.27e-005	89.5

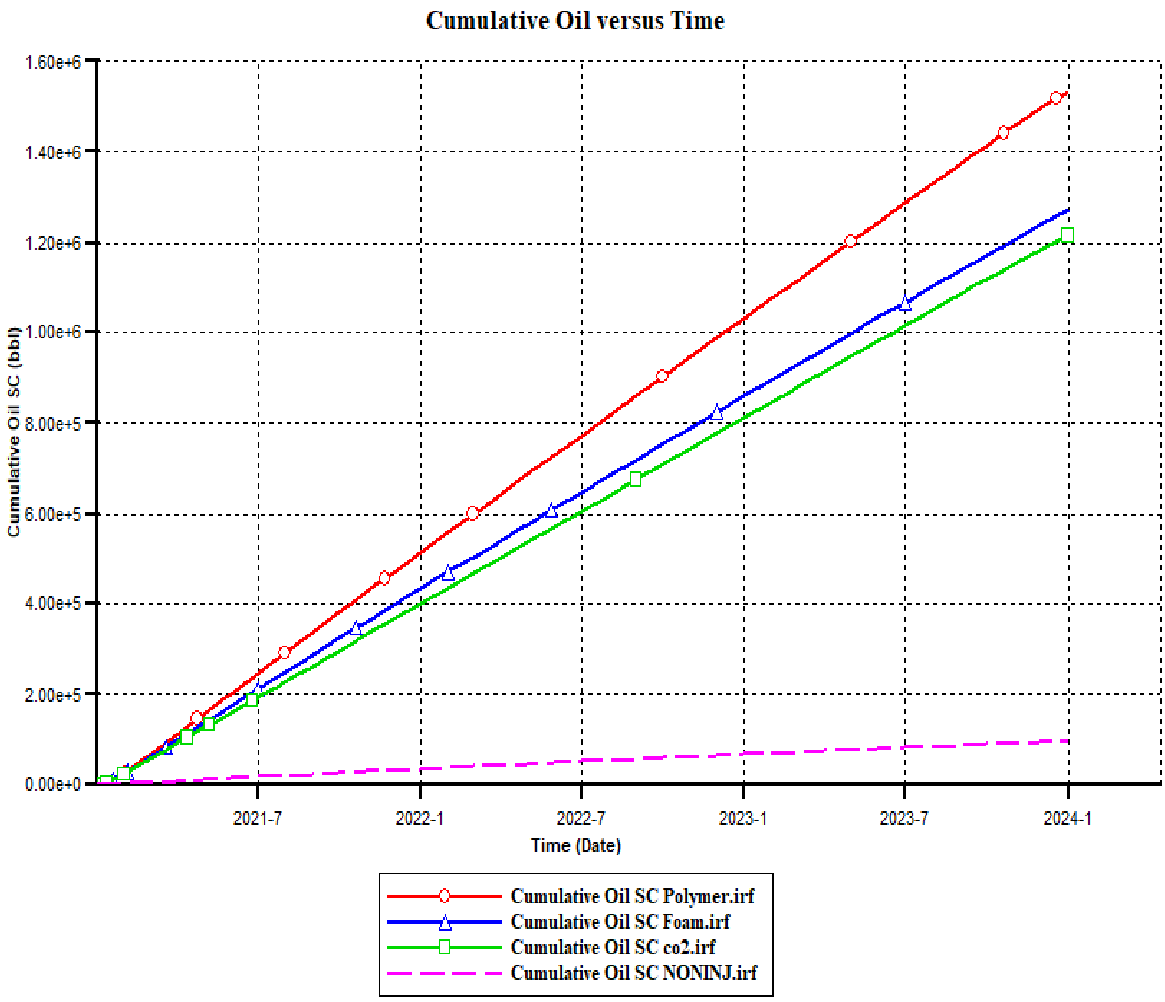

Figure 5.1. *Cumulative oil versus time results.*

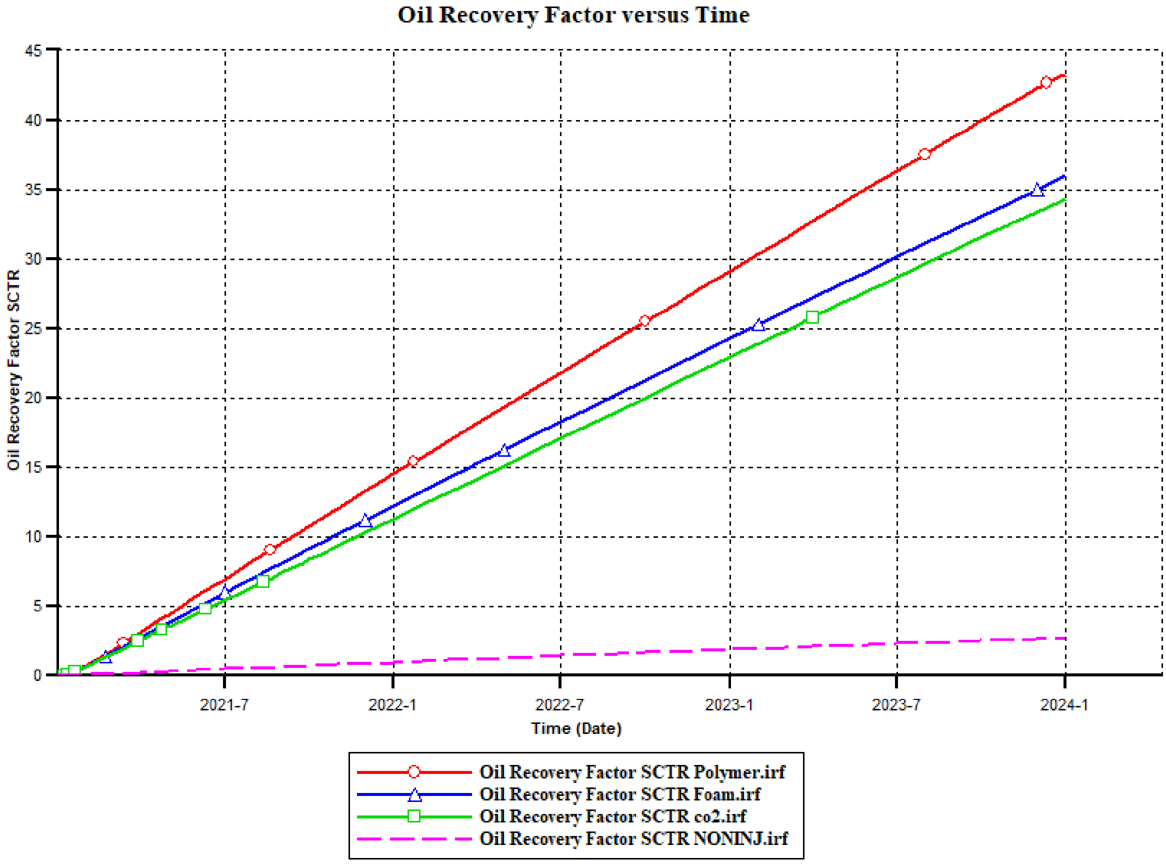

Figure 5.2. *Oil recovery versus time results.*

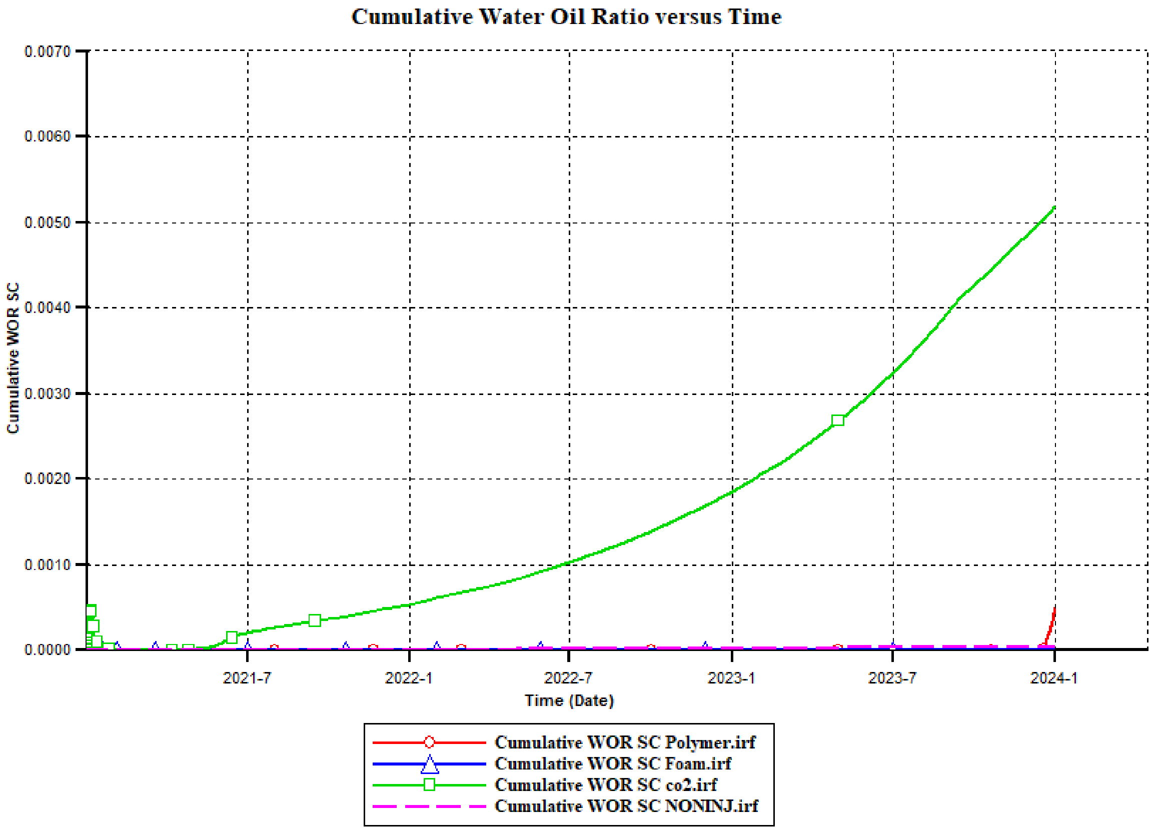

Figure 5.3. *Cumulative water oil ratio versus time results.*

Appraisal Optimization

Upon completion of the optimization process, the subsequent step is to perform an evaluation of the optimization outcome. To execute this process, a comparative analysis was conducted between the results obtained from the optimization process and those derived from two experimental research studies (Rai et al., 2014) and (Emadi, 2012).

These research studies were selected based on their relevance to the field of study and their comprehensive analyses. The outcomes of the two studies have been conducted though core measurement. The summarized results have been presented in Table 5.2. By performing this evaluation, the aim is to test our optimization method and also to become a backup to our research. The results obtained from both the simulation and experimental approaches are in closely matched indicating a high degree of accuracy and reliability in the data. It should be noted that the minor variations between the two sets of results that can be attributed to the additional recovery from natural extraction and reservoir conditions.

Table 5.2. *Comprehensive analyzes between simulation results and experimental (core analyzes) results obtained from research* (Emadi, 2012) *and* (Rai et al., 2014).

	CRF (%)	**RRF (%)**	**RF (%)**
	Experiment (Core)	**Reservoir (RRF = CRF/(Sorw+Sorg))**	**Simulation (Model)**
Polymer-Surfactant	23.45	39.2	43.3
CO_2	18	30	34.4
Foam (Surfactant)	18	30	36

CHAPTER V

Conclusion and Recommendation

Through a detailed analysis of multiple injection rate techniques, has resulted in the conclusion that Injection are ideal for use at a rate of 1500 barrels per injection. This finding is significant as it highlights the suitability of these methods for low-volume applications. Moreover CO_2 Injection have been deemed optimal for use injection rate of 1500 standard cubic feet.

Furthermore the research plan outlined the necessary criteria for ensuring the successful and efficient extraction of oil from a reservoir. Among these criteria, it has been determined that all injection methods must maintain a minimum bottom hole pressure of 1000 psi to optimize the recovery process. This guideline ensures that the pressure at the bottom of the wellbore is sufficient to extract the maximum amount of oil from the formation while minimizing the amount of water produced.

In conclusion, the results of the model analysis indicate that the polymer injection method can be considered as the most effective method for enhanced heavy oil recovery, as it yields the highest cumulative oil and has a negligible cumulative water-oil ratio. The foam injection method is ranked second in terms of effectiveness, while the carbon dioxide injection method is considered to be the least effective. These findings suggest that the polymer injection method should be considered as a priority for enhanced oil recovery efforts in the studied field. However, it is important to note that the suitability of each method depends on the specific circumstances of the field, and further evaluation is required before a final decision can be made.

Recommendation

It is recommended that, conducting additional studies to explore the potential of non-thermal techniques could contribute valuable insights to the field of heavy oil recovery.

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Appendices

Appendix A

Foam Injection CMG-STARS Data

```
INUNIT FIELD
WSRF WELL 1
WSRF GRID TIME
WSRF SECTOR TIME
OUTSRF GRID PRES SG SO SW TEMP
OUTSRF WELL LAYER NONE
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 35 35 9
KDIR DOWN
DI IVAR
 35*33.197
DJ JVAR
 35*33.197
DK ALL
 11025*7.777
DTOP
 1225*1640
VAMOD 2  0.25  0.5 0.5 0.25
VAMOD 3  0.5  0.5 1 0.5
VAMOD 4  0.5  1 0.5 0.5
**  0 = null block, 1 = active block
NULL CON            1
VATYPE ALL
 2 33*3 2 4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
 33*1 2*4 33*1 2*4 33*1 2*4 33*1 4 2 33*3 2*2 33*3 2 4 33*1 2*4 33*1
```

2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
2*4 33*1 4 2 33*3 2*2 33*3 2 4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 4 2 33*3 2*2
33*3 2 4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
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2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4
33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1
2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 2*4 33*1 4 2 33*3 2
POR CON 0.3
PERMI CON 300
PERMJ CON 300
PERMK CON 30
** 0 = pinched block, 1 = active block
PINCHOUTARRAY CON 1
END-GRID
** Model and number of components
** Model and number of components
MODEL 4 4 4 2

```
COMPNAME 'Water' 'Surfact' 'Dead_Oil' 'Soln_Gas'
CMM
0 299.41 272.455 18.8305
PCRIT
0 0 0 661.875
TCRIT
0 0 0 -83.2991
KV1
0.0 0.0 0.0 79527.3
KV2
0.0 0.0 0.0 0.00706923
KV3
0.0 0.0 0.0 -7.14924
KV4
0.0 0.0 0.0 -1583.98
KV5
0.0 0.0 0.0 -446.782
PRSR 14.6488
TEMR 100
PSURF 14.6488
TSURF 62.33
MASSDEN
62.1932 236.694 57.0382 20.6462
CP
3.07698e-006 3.07698e-006 9.9324e-006 9.9324e-006
CT1
0.000158009 0.000158009 0.000400521 0.000400521
AVG
0 0 0 2.31387e-005
BVG
0 0 0 1
VISCTABLE
**     temp
        41    1.71871    1.71871   174.518  0.649931  ** Live oil visc (P=1243.84) =
37.2203
        59     1.2843     1.2843   106.374  0.574312  ** Live oil visc (P=1243.84) =
25.1382
        77     1.0084     1.0084   67.5722   0.51274  ** Live oil visc (P=1243.84) =
17.543
       100   0.770621   0.770621   39.9231  0.449541  ** Live oil visc (P=1243.84) =
11.559
       122   0.623261   0.623261   32.3935   1254.73  ** Live oil visc (P=1243.84) =
88.9621
       158    0.45924    0.45924   23.8849    599.71  ** Live oil visc (P=1243.84) =
58.191
       230   0.289025   0.289025   7.07436   86.3994  ** Live oil visc (P=1243.84) =
14.1237
```

302 0.208683 0.208683 2.90243 20.9316 ** Live oil visc (P=1243.84) = 5.00974
374 0.165502 0.165502 1.49186 7.26345 ** Live oil visc (P=1243.84) = 2.31016
446 0.136757 0.136757 0.899465 3.24996 ** Live oil visc (P=1243.84) = 1.28267
518 0.116098 0.116098 0.60855 1.74709 ** Live oil visc (P=1243.84) = 0.814394
590 0.0997298 0.0997298 0.448153 1.07484 ** Live oil visc (P=1243.84) = 0.570673
662 0.0874608 0.0874608 0.351623 0.731397 ** Live oil visc (P=1243.84) = 0.43048
734 0.0777788 0.0777788 0.289469 0.537217 ** Live oil visc (P=1243.84) = 0.343395
806 0.0698117 0.0698117 0.247268 0.418448 ** Live oil visc (P=1243.84) = 0.285949
878 0.0631513 0.0631513 0.217376 0.341154 ** Live oil visc (P=1243.84) = 0.2462
950 0.0575005 0.0575005 0.195462 0.288296 ** Live oil visc (P=1243.84) = 0.217616
1022 0.0526459 0.0526459 0.178939 0.250663 ** Live oil visc (P=1243.84) = 0.196403
1094 0.0484303 0.0484303 0.166185 0.222973 ** Live oil visc (P=1243.84) = 0.180244
1166 0.0447353 0.0447353 0.156145 0.202031 ** Live oil visc (P=1243.84) = 0.167664
1238 0.0414701 0.0414701 0.148107 0.185826 ** Live oil visc (P=1243.84) = 0.157687
1310 0.0385638 0.0385638 0.141578 0.173038 ** Live oil visc (P=1243.84) = 0.149649
1382 0.0359604 0.0359604 0.13621 0.162779 ** Live oil visc (P=1243.84) = 0.143083
1454 0.0336148 0.0336148 0.131746 0.154429 ** Live oil visc (P=1243.84) = 0.137657
1526 0.0314905 0.0314905 0.127999 0.147547 ** Live oil visc (P=1243.84) = 0.133125
VSMIXCOMP 'Soln_Gas'
VSMIXENDP 0.00592147 0.29
VSMIXFUNC 0.00592147 0.0909966 0.144499 0.180071 0.206437 0.22598 0.241576 0.253898 0.264034 0.272472 0.279827
ROCKFLUID
RPT 1 WATWET
INTCOMP 'Surfact' WATER
IFTTABLE
** Composition of component/phase Interfacial tension
0 30
0.001 1

```
INTLIN
FMMOB 20
KRINTRP 1
DTRAPW 1
DTRAPN 1
**        Sw         krw        krow
**        Sw        krw        krow
SWT
         0.2           0           1
      0.23125  0.00152588    0.878906
       0.2625  0.00610352    0.765625
      0.29375   0.0137329    0.660156
        0.325   0.0244141      0.5625
      0.35625    0.038147    0.472656
       0.3875   0.0549316    0.390625
      0.41875   0.0747681    0.316406
         0.45   0.0976562        0.25
      0.48125    0.123596    0.191406
       0.5125    0.152588    0.140625
      0.54375    0.184631   0.0976563
        0.575    0.219727      0.0625
      0.60625    0.257874   0.0351563
       0.6375    0.299072    0.015625
      0.66875    0.343323  0.00390625
          0.7    0.390625           0
         0.85    0.660156           0
            1           1           0
**        Sl        krg       krog
**        Sl          krg        krog
SLT
         0.2         0.3           0
        0.35       0.192           0
         0.5       0.108           0
    0.528125    0.0949219  0.00316406
     0.55625    0.0826875   0.0126563
    0.584375    0.0712969   0.0284766
      0.6125      0.06075    0.050625
    0.640625    0.0510469   0.0791016
     0.66875    0.0421875    0.113906
    0.696875    0.0341719    0.155039
       0.725        0.027      0.2025
    0.753125    0.0206719    0.256289
     0.78125    0.0151875    0.316406
    0.809375    0.0105469    0.382852
      0.8375      0.00675    0.455625
    0.865625   0.00379687    0.534727
     0.89375    0.0016875    0.620156
```

0.921875 0.000421875 0.711914
0.95 0 0.81
0.975 0 0.9025
1 0 1
KRINTRP 2
DTRAPW 0.047619
DTRAPN 0.047619
** Sw krw krow
SWT
0.25 0 1
0.271875 0.000850694 0.878906
0.29375 0.00340278 0.765625
0.315625 0.00765625 0.660156
0.3375 0.0136111 0.5625
0.359375 0.0212674 0.472656
0.38125 0.030625 0.390625
0.403125 0.041684 0.316406
0.425 0.0544444 0.25
0.446875 0.0689063 0.191406
0.46875 0.0850694 0.140625
0.490625 0.102934 0.0976563
0.5125 0.1225 0.0625
0.534375 0.143767 0.0351562
0.55625 0.166736 0.015625
0.578125 0.191406 0.00390625
0.6 0.217778 0
0.8 0.537778 0
1 1 0
** Sl krg krog
** Sl krg krog
SLT
0.25 0.3 0
0.475 0.138138 0
0.7 0.0382653 0
0.715625 0.0336316 0.00271267
0.73125 0.0292969 0.0108507
0.746875 0.0252611 0.0244141
0.7625 0.0215242 0.0434028
0.778125 0.0180863 0.0678168
0.79375 0.0149474 0.0976563
0.809375 0.0121074 0.132921
0.825 0.00956633 0.173611
0.840625 0.00732422 0.219727
0.85625 0.00538106 0.271267
0.871875 0.00373685 0.328234
0.8875 0.00239158 0.390625
0.903125 0.00134526 0.458442

```
     0.91875  0.000597895    0.531684
    0.934375  0.000149474    0.610352
        0.95            0    0.694444
       0.975            0    0.840278
           1            0           1
KRWIRO 0.047619
KRGCW 0.105
ADSCOMP 'Surfact' WATER
ADSTABLE
**     Mole Fraction  Adsorbed moles per unit pore volume
                  0                               0
    6.024164656e-005                   0.0004573024163
ADMAXT 0.000457302
INTERP_ENDS ON
INITIAL
VERTICAL DEPTH_AVE

INITREGION 1
REFPRES 1243.844
REFDEPTH 1640
MFRAC_WAT 'Water' CON           1
MFRAC_OIL 'Soln_Gas' CON     0.276272
MFRAC_OIL 'Dead_Oil' CON     0.723728
NUMERICAL
TFORM ZT
ISOTHERMAL
RUN
DATE 2021 1 1
DTWELL 0.001
**
WELL  'Injector 1'  FRAC  0.25
INJECTOR MOBWEIGHT EXPLICIT 'Injector 1'
INCOMP  WATER  0.9  0.1  0.0  0.0
OPERATE  MAX  BHP  6200.0  CONT
OPERATE  MAX  STW  1500.0  CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF     GEOA  'Injector 1'
** UBA            ff         Status  Connection
    1 1 1         1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
    1 1 2         1.0  OPEN    FLOW-FROM  1
    1 1 3         1.0  OPEN    FLOW-FROM  2
    1 1 4         1.0  OPEN    FLOW-FROM  3
    1 1 5         1.0  OPEN    FLOW-FROM  4
    1 1 6         1.0  OPEN    FLOW-FROM  5
    1 1 7         1.0  OPEN    FLOW-FROM  6
    1 1 8         1.0  OPEN    FLOW-FROM  7
```

```
   1 1 9        1.0  OPEN    FLOW-FROM  8
**
WELL  'Injector 2'  FRAC  0.25
INJECTOR MOBWEIGHT EXPLICIT 'Injector 2'
INCOMP  WATER  0.9  0.1  0.0  0.0
OPERATE  MAX  BHP  6200.0  CONT
OPERATE  MAX  STW  1500.0  CONT
**         rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF     GEOA  'Injector 2'
** UBA            ff         Status  Connection
   35 35 1        1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   35 35 2        1.0  OPEN    FLOW-FROM  1
   35 35 3        1.0  OPEN    FLOW-FROM  2
   35 35 4        1.0  OPEN    FLOW-FROM  3
   35 35 5        1.0  OPEN    FLOW-FROM  4
   35 35 6        1.0  OPEN    FLOW-FROM  5
   35 35 7        1.0  OPEN    FLOW-FROM  6
   35 35 8        1.0  OPEN    FLOW-FROM  7
   35 35 9        1.0  OPEN    FLOW-FROM  8
**
WELL  'Injector 3'  FRAC  0.25
INJECTOR MOBWEIGHT EXPLICIT 'Injector 3'
INCOMP  WATER  0.9  0.1  0.0  0.0
OPERATE  MAX  BHP  6200.0  CONT
OPERATE  MAX  STW  1500.0  CONT
**         rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF     GEOA  'Injector 3'
** UBA            ff         Status  Connection
   1 35 1        1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   1 35 2        1.0  OPEN    FLOW-FROM  1
   1 35 3        1.0  OPEN    FLOW-FROM  2
   1 35 4        1.0  OPEN    FLOW-FROM  3
   1 35 5        1.0  OPEN    FLOW-FROM  4
   1 35 6        1.0  OPEN    FLOW-FROM  5
   1 35 7        1.0  OPEN    FLOW-FROM  6
   1 35 8        1.0  OPEN    FLOW-FROM  7
   1 35 9        1.0  OPEN    FLOW-FROM  8
**
WELL  'Injector 4'  FRAC  0.25
INJECTOR MOBWEIGHT EXPLICIT 'Injector 4'
INCOMP  WATER  0.9  0.1  0.0  0.0
OPERATE  MAX  BHP  6200.0  CONT
OPERATE  MAX  STW  1500.0  CONT
**         rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
```

```
    PERF     GEOA  'Injector 4'
** UBA            ff        Status  Connection
   35 1 1        1.0  OPEN   FLOW-FROM  'SURFACE'  REFLAYER
   35 1 2        1.0  OPEN   FLOW-FROM  1
   35 1 3        1.0  OPEN   FLOW-FROM  2
   35 1 4        1.0  OPEN   FLOW-FROM  3
   35 1 5        1.0  OPEN   FLOW-FROM  4
   35 1 6        1.0  OPEN   FLOW-FROM  5
   35 1 7        1.0  OPEN   FLOW-FROM  6
   35 1 8        1.0  OPEN   FLOW-FROM  7
   35 1 9        1.0  OPEN   FLOW-FROM  8
**
WELL  'Producer 1'  FRAC  1.0
PRODUCER 'Producer 1'
OPERATE  MIN  BHP  1000.0  CONT
OPERATE  MAX  STL  12000.0  CONT
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'Producer 1'
** UBA            ff        Status  Connection
   18 18 1       1.0  OPEN   FLOW-TO  'SURFACE'  REFLAYER
   18 18 2       1.0  OPEN   FLOW-TO  1
   18 18 3       1.0  OPEN   FLOW-TO  2
   18 18 4       1.0  OPEN   FLOW-TO  3
   18 18 5       1.0  OPEN   FLOW-TO  4
   18 18 6       1.0  OPEN   FLOW-TO  5
   18 18 7       1.0  OPEN   FLOW-TO  6
   18 18 8       1.0  OPEN   FLOW-TO  7
   18 18 9       1.0  OPEN   FLOW-TO  8
DATE 2021 2  1.00000
DATE 2021 3  1.00000
DATE 2021 4  1.00000
DATE 2021 5  1.00000
DATE 2021 6  1.00000
DATE 2021 7  1.00000
DATE 2021 8  1.00000
DATE 2021 9  1.00000
DATE 2021 10  1.00000
DATE 2021 11  1.00000
DATE 2021 12  1.00000
DATE 2022 1  1.00000
DATE 2022 2  1.00000
DATE 2022 3  1.00000
DATE 2022 4  1.00000
DATE 2022 5  1.00000
DATE 2022 6  1.00000
DATE 2022 7  1.00000
```

DATE 2022 8 1.00000
DATE 2022 9 1.00000
DATE 2022 10 1.00000
DATE 2022 11 1.00000
DATE 2022 12 1.00000
DATE 2023 1 1.00000
DATE 2023 2 1.00000
DATE 2023 3 1.00000
DATE 2023 4 1.00000
DATE 2023 5 1.00000
DATE 2023 6 1.00000
DATE 2023 7 1.00000
DATE 2023 8 1.00000
DATE 2023 9 1.00000
DATE 2023 10 1.00000
DATE 2023 11 1.00000
DATE 2023 12 1.00000
DATE 2024 1 1.00000
STOP
DATE 2024 2 1.00000
DATE 2024 3 1.00000
DATE 2024 4 1.00000
DATE 2024 5 1.00000
DATE 2024 6 1.00000
DATE 2024 7 1.00000
DATE 2024 8 1.00000
DATE 2024 9 1.00000
DATE 2024 10 1.00000
DATE 2024 11 1.00000
DATE 2024 12 1.00000
DATE 2025 1 1.00000
DATE 2025 2 1.00000
DATE 2025 3 1.00000
DATE 2025 4 1.00000
DATE 2025 5 1.00000
DATE 2025 6 1.00000
DATE 2025 7 1.00000
DATE 2025 8 1.00000
DATE 2025 9 1.00000
DATE 2025 10 1.00000
DATE 2025 11 1.00000
DATE 2025 12 1.00000
DATE 2026 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 0.448397 1.03072 1.1288 23.2705 0.0119415 899.66 0.70378 4.35113e-006
RESULTS PVTIMEX TABLE 666.304 1.71147 1.0331 0.169873 34.4479 0.0120062 898.558 4.6766 4.35113e-006
RESULTS PVTIMEX TABLE 1231.28 3.17702 1.03588 0.0909678 45.5828 0.0120925 897.271 8.73309 4.35113e-006
RESULTS PVTIMEX TABLE 1796.26 4.77155 1.03893 0.0617048 55.9006 0.0121934 895.856 12.8747 4.35113e-006
RESULTS PVTIMEX TABLE 2361.24 6.46372 1.0422 0.0464507 65.2172 0.0123069 894.335 17.1026 4.35113e-006
RESULTS PVTIMEX TABLE 2926.22 8.23547 1.04565 0.037092 73.5356 0.012432 892.73 21.4178 4.35113e-006
RESULTS PVTIMEX TABLE 3491.2 10.0749 1.04926 0.0307672 80.9272 0.0125682 891.052 25.8206 4.35113e-006
RESULTS PVTIMEX TABLE 4056.17 11.9735 1.05302 0.0262092 87.4865 0.0127152 889.302 30.3111 4.35113e-006
RESULTS PVTIMEX TABLE 4621.15 13.9249 1.05691 0.0227706 93.3105 0.012873 887.496 34.8884 4.35113e-006
RESULTS PVTIMEX TABLE 5186.13 15.9241 1.06094 0.020086 98.4912 0.0130418 885.622 39.5513 4.35113e-006
RESULTS PVTIMEX TABLE 5751.11 17.9669 1.06508 0.0179338 103.11 0.0132214 883.703 44.2978 4.35113e-006
RESULTS PVTIMEX TABLE 6316.09 20.0501 1.06934 0.0161717 107.24 0.0134121 881.73 49.1248 4.35113e-006
RESULTS PVTIMEX TABLE 6881.07 22.1708 1.07371 0.014704 110.943 0.0136138 879.711 54.0282 4.15037e-006
RESULTS PVTIMEX TABLE 7446.04 24.3266 1.07819 0.0134642 114.274 0.0138268 877.644 59.0033 3.74425e-006
RESULTS PVTIMEX TABLE 8011.02 26.5154 1.08276 0.0124045 117.28 0.0140511 875.545 64.0438 3.40365e-006
RESULTS PVTIMEX TABLE 8576 28.7353 1.08744 0.0114897 120 0.0142866 873.399 69.1427 3.11438e-006
RESULTS PVTIMEX TABLE 9260.8 31.4656 1.08535 0.0105378 120 0.014587 875.085 75.3889 2.81784e-006
RESULTS PVTIMEX TABLE 9945.6 34.2368 1.08363 0.00972469 120 0.0149035 876.471 81.692 2.56794e-006
RESULTS PVTIMEX TABLE 10630.4 37.0467 1.0822 0.00902421 120 0.0152357 877.624 88.0332 2.35482e-006
RESULTS PVTIMEX TABLE 11315.2 39.8934 1.08101 0.0084163 120 0.0155829 878.594 94.3918 2.17118e-006
RESULTS PVTIMEX TABLE 12000 42.775 1.08 0.00788538 120 0.0159444 879.415 100.747 2.0115e-006
RESULTS PVTIMEX TABLEDO 37.7778 420
RESULTS PVTIMEX TABLEDO 50 340
RESULTS PVTIMEX TABLEDO 70 250
RESULTS PVTIMEX TRES 54.4444
RESULTS PVTIMEX BPP 15

RESULTS PVTIMEX BWI 1.00976
RESULTS PVTIMEX DENSITYWATER 1000
RESULTS PVTIMEX VISCOSITYWATER 0.567336
RESULTS PVTIMEX WATERCVW 0
RESULTS PVTIMEX DENSITYOIL 926.941
RESULTS PVTIMEX GASGRAVITY 0.65
RESULTS PVTIMEX WATERCOMP 4.41287e-007
RESULTS PVTIMEX REFPW 8576
RESULTS PVTIMEX CVO 0
RESULTS PVTIMEX RATIODEADPVT 0.0734425
RESULTS PVTIMEX VISCPRESSURE 101.3
RESULTS PVTIMEX COMPOSITION 2 0.738607 0.261393
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 0.448397 1.03072 1.1288 23.2705 0.0119415 899.66 0.70378 4.35113e-006
RESULTS PVTIMEX TABLE 666.304 1.71147 1.0331 0.169873 34.4479 0.0120062 898.558 4.6766 4.35113e-006
RESULTS PVTIMEX TABLE 1231.28 3.17702 1.03588 0.0909678 45.5828 0.0120925 897.271 8.73309 4.35113e-006
RESULTS PVTIMEX TABLE 1796.26 4.77155 1.03893 0.0617048 55.9006 0.0121934 895.856 12.8747 4.35113e-006
RESULTS PVTIMEX TABLE 2361.24 6.46372 1.0422 0.0464507 65.2172 0.0123069 894.335 17.1026 4.35113e-006
RESULTS PVTIMEX TABLE 2926.22 8.23547 1.04565 0.037092 73.5356 0.012432 892.73 21.4178 4.35113e-006
RESULTS PVTIMEX TABLE 3491.2 10.0749 1.04926 0.0307672 80.9272 0.0125682 891.052 25.8206 4.35113e-006
RESULTS PVTIMEX TABLE 4056.17 11.9735 1.05302 0.0262092 87.4865 0.0127152 889.302 30.3111 4.35113e-006
RESULTS PVTIMEX TABLE 4621.15 13.9249 1.05691 0.0227706 93.3105 0.012873 887.496 34.8884 4.35113e-006
RESULTS PVTIMEX TABLE 5186.13 15.9241 1.06094 0.020086 98.4912 0.0130418 885.622 39.5513 4.35113e-006
RESULTS PVTIMEX TABLE 5751.11 17.9669 1.06508 0.0179338 103.11 0.0132214 883.703 44.2978 4.35113e-006
RESULTS PVTIMEX TABLE 6316.09 20.0501 1.06934 0.0161717 107.24 0.0134121 881.73 49.1248 4.35113e-006
RESULTS PVTIMEX TABLE 6881.07 22.1708 1.07371 0.014704 110.943 0.0136138 879.711 54.0282 4.15037e-006
RESULTS PVTIMEX TABLE 7446.04 24.3266 1.07819 0.0134642 114.274 0.0138268 877.644 59.0033 3.74425e-006

RESULTS PVTIMEX TABLE 8011.02 26.5154 1.08276 0.0124045 117.28 0.0140511 875.545 64.0438 3.40365e-006
RESULTS PVTIMEX TABLE 8576 28.7353 1.08744 0.0114897 120 0.0142866 873.399 69.1427 3.11438e-006
RESULTS PVTIMEX TABLE 9260.8 31.4656 1.08535 0.0105378 120 0.014587 875.085 75.3889 2.81784e-006
RESULTS PVTIMEX TABLE 9945.6 34.2368 1.08363 0.00972469 120 0.0149035 876.471 81.692 2.56794e-006
RESULTS PVTIMEX TABLE 10630.4 37.0467 1.0822 0.00902421 120 0.0152357 877.624 88.0332 2.35482e-006
RESULTS PVTIMEX TABLE 11315.2 39.8934 1.08101 0.0084163 120 0.0155829 878.594 94.3918 2.17118e-006
RESULTS PVTIMEX TABLE 12000 42.775 1.08 0.00788538 120 0.0159444 879.415 100.747 2.0115e-006
RESULTS PVTIMEX TABLEDO 37.7778 420
RESULTS PVTIMEX TABLEDO 50 340
RESULTS PVTIMEX TABLEDO 70 250
RESULTS PVTIMEX TRES 54.4444
RESULTS PVTIMEX BPP 15
RESULTS PVTIMEX BWI 1.00976
RESULTS PVTIMEX DENSITYWATER 1000
RESULTS PVTIMEX VISCOSITYWATER 0.567336
RESULTS PVTIMEX WATERCVW 0
RESULTS PVTIMEX DENSITYOIL 926.941
RESULTS PVTIMEX GASGRAVITY 0.65
RESULTS PVTIMEX WATERCOMP 4.41287e-007
RESULTS PVTIMEX REFPW 8576
RESULTS PVTIMEX CVO 0
RESULTS PVTIMEX RATIODEADPVT 0.0734425
RESULTS PVTIMEX VISCPRESSURE 101.3
RESULTS PVTIMEX COMPOSITION 2 0.738607 0.261393
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 0.483675 1.01616 1.07101 39.3277 0.0113362 912.578 0.74176 4.35113e-006
RESULTS PVTIMEX TABLE 666.304 1.84613 1.0186 0.160858 49.4947 0.0114104 911.455 4.93871 4.35113e-006
RESULTS PVTIMEX TABLE 1231.28 3.42697 1.02146 0.0859623 59.4247 0.011508 910.132 9.2416 4.35113e-006
RESULTS PVTIMEX TABLE 1796.26 5.14696 1.02461 0.0581835 68.4438 0.0116218 908.668 13.6539 4.35113e-006
RESULTS PVTIMEX TABLE 2361.24 6.97227 1.02799 0.0437015 76.4314 0.0117498 907.091 18.1785 4.35113e-006

RESULTS PVTIMEX TABLE 2926.22 8.88341 1.03157 0.0348149 83.4329 0.0118911 905.414 22.8187 4.35113e-006
RESULTS PVTIMEX TABLE 3491.2 10.8676 1.03533 0.0288083 89.5471 0.0120455 903.649 27.5764 4.35113e-006
RESULTS PVTIMEX TABLE 4056.17 12.9156 1.03925 0.0244788 94.8854 0.0122129 901.806 32.4538 4.35113e-006
RESULTS PVTIMEX TABLE 4621.15 15.0205 1.04332 0.0212121 99.5537 0.0123936 899.89 37.4517 4.35113e-006
RESULTS PVTIMEX TABLE 5186.13 17.177 1.04753 0.0186616 103.647 0.0125879 897.909 42.5704 4.30218e-006
RESULTS PVTIMEX TABLE 5751.11 19.3805 1.05188 0.0166169 107.248 0.012796 895.86 47.8086 3.75758e-006
RESULTS PVTIMEX TABLE 6316.09 21.6276 1.05636 0.014943 110.428 0.0130183 893.751 53.164 3.32433e-006
RESULTS PVTIMEX TABLE 6881.07 23.9151 1.06096 0.0135494 113.247 0.0132553 891.589 58.6322 2.9724e-006
RESULTS PVTIMEX TABLE 7446.04 26.2405 1.06568 0.0123729 115.754 0.0135071 889.373 64.2072 2.68155e-006
RESULTS PVTIMEX TABLE 8011.02 28.6015 1.07051 0.0113683 117.993 0.0137741 887.113 69.881 2.43761e-006
RESULTS PVTIMEX TABLE 8576 30.9962 1.07546 0.0105023 120 0.0140563 884.799 75.6432 2.23045e-006
RESULTS PVTIMEX TABLE 9260.8 33.9412 1.07398 0.00960292 120 0.0144187 886.021 82.728 2.01807e-006
RESULTS PVTIMEX TABLE 9945.6 36.9305 1.07276 0.00883697 120 0.0148033 887.027 89.8985 1.8391e-006
RESULTS PVTIMEX TABLE 10630.4 39.9614 1.07175 0.00817956 120 0.0152091 887.864 97.1238 1.68647e-006
RESULTS PVTIMEX TABLE 11315.2 43.032 1.0709 0.00761162 120 0.0156353 888.567 104.371 1.55495e-006
RESULTS PVTIMEX TABLE 12000 46.1404 1.07018 0.0071182 120 0.0160802 889.163 111.605 1.44059e-006
RESULTS PVTIMEX TABLEDO 37.7778 420
RESULTS PVTIMEX TABLEDO 50 340
RESULTS PVTIMEX TABLEDO 70 250
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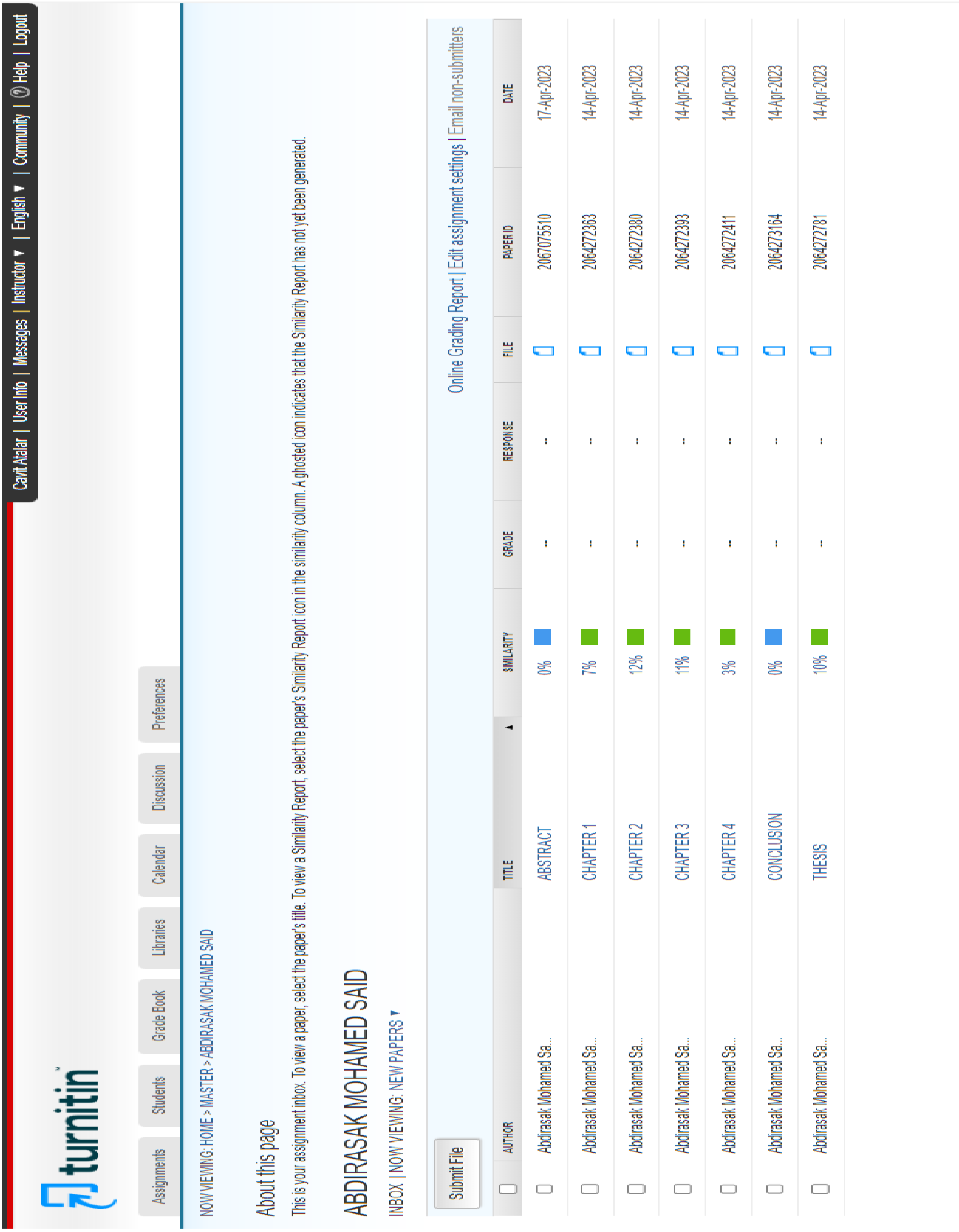
Appendix B
Turnitin Similarity Report



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Appendix C

Ethical Approval Letter

YAKIN DOĞU ÜNİVERSİTESİ
ETHICAL APROVAL DOCUMENT

Date: 17/04/2023

To the **Institute of Graduate Studies**

The research project titled "**ASSESSMENT OF POLYMER, FOAM AND CO_2 INJECTIONS FOR HEAVY OIL PRODUCTION USING NUMERICAL SIMULATION**'' 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