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SIMULATION OF STEAM INJECTION FOR ENHANCING OIL RECOVERY IN PELICAN LAKE FIELD, CANADA

MASTER THESIS

2024

NEAR EAST UNIVERSITY

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Supervisor
Prof. Dr. Cavit ATALAR

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Approval

We certify that we have read the Project submitted by Elie Mayombo BIYOWA titled **"Simulation of Steam Injection for Enhancing Oil Recovery in Pelican Lake Field, Canada"** and that in our combined opinion it is fully adequate, in scope and quality, as a Project for the degree of Master of Applied Sciences.

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Declaration of Ethical Principles

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

Mayombo

Elie Mayombo BIYOWA

26/06/2024

Acknowledgments

First and foremost, I would like to commend the effort of my supervisor Prof. Dr. Cavit Atalar for being a father. I will like to seize this opportunity to thank and acknowledge the effort made by my wife Carol Meta Tshibanda and my mother Catherine Muenyi, for nurturing me to become what I am today. Also, I will like to acknowledge Prof. Dr. Salih Saner, Prof. Dr. Kamil Dimililer, and MSc. Sharon Muloh Gariba, for the guidance and support they rendered to me during my studies at Near East University.

Moreover, I would like to recognize the efforts made by my Professors from Kinshasha University in Democratic Republic of Congo (DRC). Some of which are; Prof. Dr. Valentin Kanda Nkula, Prof. Dr. Emmanuel Cibambula Cia Musau, and Prof. Dr. Raphael Matamba Jibikila for their support and guidance during my undergraduate studies. Lastly, I will like to acknowledge my late Father Mr. Clement Biyowa, who died at my early childhood, your memory will live on with us forever.

Elie Mayombo BIYOWA

Abstract

Simulation of Steam Injection for Enhancing Oil Recovery in Pelican Lake Field, Canada

Elie Mayombo, BIYOWA

MSc. Department of Petroleum and Natural Gas Engineering

June 2024, 63 Pages

The model used is a two-phase (water, oil) system with one producer at the center of two injectors arranged perpendicular to each other on a Cartesian grid design (15 x 15 x 5). The simulation is said to run for a 10-year period on data obtained from Pelican Lake Field in Canada. The producer is run on a 2000 Psi lowest pressure in the bottom of the hole, and 4000 bbls rate of oil at the surface. Conversely, there are two injectors maintained at same operating constraint are set at a maximum pressure in the bottom of the hole of 8000 Psi and a rate of surface gas set at 2-million ft^3 per-day in order to inject steam. Six different models were constructed with the same orientation in this research. The first of which is a no injection model with only a producer without injection. Subsequently, the first or normal injection is used to inject steam with 0.75 quality- 6000 psi pressure, and 600 °F temperature. Afterwards, four other models were created some of which have increased or decreased steam attributes.

Result of the simulation has shown the no injection model to have a negligeable recovery factor due to no EOR, cumulative oil production of 109 bbl./day. However, the first or normal injection model recorded a recovery factor of 70% with cumulative oil production of 155000 bbls. Consequently, all other models (second, third, fourth, and fifth) gave same or nearly same values of oil recovery and cumulative oil production as the first injection. This is because the steam attributes are increased or decreased simultaneously. Hence, our research finding suggests that to alter oil recovery in steam injection either injection pressure or temperature is to be increased or decreased accordingly.

Keywords**:** steam injection, numerical simulation, oil recovery, steam attributes, heavy oil reservoirs.

Özet

Pelican Lake Field, Kanada'da Petrol Geri Kazanımını Artırmak için Buhar Enjeksiyonu Simülasyonu

Elie Mayombo, BIYOWA

Yüksek Lisans. Petrol ve Doğal Gaz Mühendisliği Bölümü

Haziran 2024, 63 Sayfa

Kullanılan model, Kartezyen ızgara tasarımı (15 x 15 x 5) üzerinde birbirine dik olarak yerleştirilmiş iki enjektörün merkezinde bir üreticinin bulunduğu inky fazlı (su, yağ) bir sistemdir. Simülasyonun Kanada'daki Pelican Lake Field'dan elde edilen veriler üzerinden 10 yıllık bir süre boyunca çalışacağı söyleniyor. Üretici, kuyunun dibinde 2000 psi'lik en düşük basınçta ve yüzeyde 4000 varil oranında petrolle çalıştırılır. Tersine, aynı çalışma kısıtlamasında tutulan, kuyunun tabanında 8000 psi'lik bir maksimum basınca ve buhar enjekte etmek için günde 2 milyon ft3'e ayarlanmış bir yüzey gazı oranına ayarlanmış iki enjektör vardır. Bu araştırmada aynı yönelimle altı farklı model oluşturulmuştur. Bunlardan ilki, yalnızca enjeksiyonsuz üreticinin bulunduğu enjeksiyonsuz modeldir. Daha sonra ilk veya normal enjeksiyon kullanılarak 0,75 kalite - 6000 psi basınç ve 600 °F sıcaklıkta buhar enjekte edilir. Daha sonra bazıları artırılmış, bazıları azaltılmış buhar özelliğine sahip dört model daha oluşturuldu.

Simülasyonun sonucu, enjeksiyonsuz modelin, EOR olmaması nedeniyle ihmal edilebilir bir kurtarma faktörüne sahip olduğunu, kümülatif petrol üretiminin 109 varil/gün olduğunu göstermiştir. Bununla birlikte, ilk veya normal enjeksiyon modeli, 155.000 varil/gün kümülatif petrol üretimi ile %70'lik bir geri kazanım faktörü kaydetti. Sonuç olarak, diğer tüm modeller (ikinci, üçüncü, dördüncü ve beşinci), ilk enjeksiyonla aynı veya hemen hemen aynı petrol geri kazanımı ve kümülatif petrol üretimi değerlerini verdi. Bunun nedeni buhar özelliklerinin eş zamanlı olarak arttırılması veya azaltılmasıdır. Dolayısıyla araştırma bulgumuz, buhar enjeksiyonunda yağ geri kazanımını değiştirmek için enjeksiyon basıncının veya sıcaklığının buna göre arttırılması veya azaltılması gerektiğini göstermektedir.

***Anahtar Kelimeler*:** buhar enjeksiyonu, sayısal simülasyon, petrol geri kazanımı, buhar özellikleri, ağır petrol rezervuarları.

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List of Abbreviations

ASP:	Alkaline-Surfactant-Polymer
Bbls:	Barrels
BOPD:	Barrels of Oil Per Day
CCS:	Cyclic Steam Stimulation
CMG:	Computer Modeling Group
CO_2:	Carbon di-oxide
CSI:	Cyclic Steam Injection
EOR:	Enhanced Oil Recovery
GORs:	Gas Oil Ratios
HC:	Hydrocarbon
IFT:	Interfacial Tension
IOR:	Improved Oil Recovery
MPC:	Model Predictive Control
NCG:	Non-Condensable Gas
NPV:	Net Pay Value
O/W:	Oil Water Ratio
POVO:	Average Pressure
RF:	Recovery Factor
RL:	Reinforcement Learning
SAGD:	Steam Assisted Gravity Drainage
SARSA:	State-Action-Reward-State-Action
(Sg, So, Sw):	Gas, Oil, and Water Saturations
STARS:	Thermal Simulator

CHAPTER I

Introduction

This chapter will serve as the basis of our research thesis, it will provide background to our research and established critical understand of the whole work. The Proper perspective to Pelican Lake Field, heavy oil reservoirs, heavy oil recovery, thermal techniques, and steam flooding would be given. Moreover, the research aim, objectives, scope, limitation, and problem statement would be explained.

General Overview of Pelican Lake Field, Canada

The biggest navigable lake in Canada's southwest province of Manitoba is called Pelican Lake. It has a surface area of 27.8 square kilometers, or 10.7 square miles, and is around 18 kilometers (11 miles) long by 1.6 kilometers (1 mile) broad. With a maximum depth of 5.2 meters and a mean depth of 3.8 meters, Pelican Lake is quite shallow. At 412.0 meters above sea level, the lake can accommodate 108 billion liters of water. The lake is controlled, and 412.0 meters is the typical summer goal level. The Orthez drain is the primary of numerous tiny streams that feed the lake. There are 686 square kilometers (265 square miles) of drainage area overall. With the advent of horizontal drilling, the field started to realize its full potential and was among the first in the world to be exploited using horizontal wells. The opportunity for enhanced oil recovery (EOR) is substantial, though, given that primary recovery is less than 10% and there are 6.4 billion barrels of oil in place (OIP).

Prior to the notion of combining polymer flooding with horizontal wells, the high viscosity of the oil made it unfeasible as an EOR technique for Pelican Lake. After learning from the first unsuccessful pilot's implementation in 1997, a second pilot was successfully launched in 2006. In this trial, the reaction to polymer injection was outstanding; the oil rate increased from 43 BOPD to over 700 BOPD and stayed high for over 6 years; overall, the water cut has stayed below 60%. Although it varies, incremental recovery above initial production can occasionally account for up to 25% of the oil that was originally in place (OOIP) (Delamaide et al., 2014). Figure 1.1 will depict the map and location of the Pelican Lake Field, Canada.

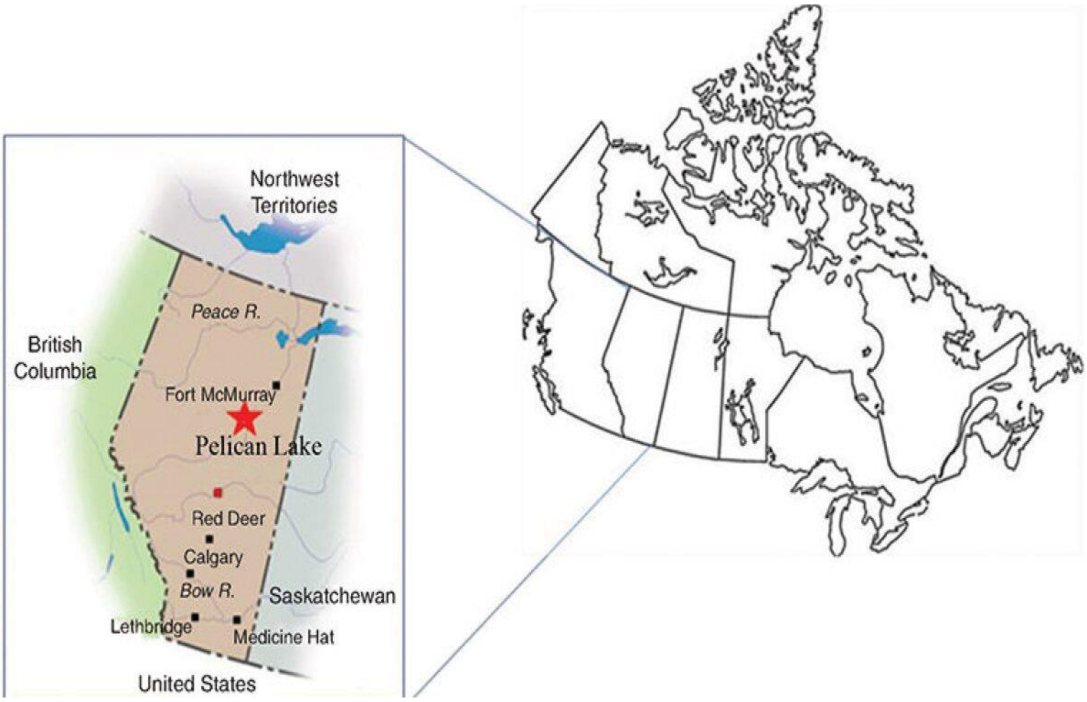

Figure 1.1. The Map and location of Pelican Lake Field, Canada (Delamaide et al., 2014).

Study Background

With the recent global demand for energy-by-energy industries it becomes paramount to investigate feasible ways of producing oil commercially. Alvarado and Manrique (2010) stated that established fields are the source of the majority of the oil produced globally today. Increasing oil recovery from older resources is a major challenge for oil companies and regulators. Furthermore, the pace at which newly discovered reserves are being replaced by produced reserves has been steadily declining over the past three decades. Raising mature fields' recovery factors under conventional and secondary production will thus be crucial to meeting the growing demand for energy in the next years (Alvarado & Manrique, 2010). It is clear that heavy oil and oil sands make up the majority of oil resources, and several types of literature reviews were done to determine their potential.

Petroleum is generally found in the sub-surface pores, before the advent of technology the oil produced is generally conventional with low viscosity and sulphur deposit, as technology emerges oil with high viscosity and sulphur content is produced, generally referred to as heavy oil. It also becomes a huge burden in the industry to process this oil due to its high viscosity and sulphur content. Heavy crude oil is generally referred to as high viscosity oil due to its low number of volatile constituents and with high amount of heavy molecular weight constituents as oppose to conventional crude oil (Temizel et al., 2018). Due to its heaviness recovery from such heavy oil reservoirs becomes a rigorous task, processing, and also transportation. The aforementioned factors seriously affect the economics related to exploration and production (E & P) of heavy oil resources. Hence, devising an economically viable means to produce this heavy oil resources becomes eminent. Generally, crude oil is classified based on their API gravity, with low value API being heavy oil and the reverse is the case for light oil (Temizel et al., 2018). With a viscosity of 1000cp or above, heavy crude is a hydrocarbon that is exceedingly viscous and difficult to flow. Most unconventional oil, including bitumen and tar sands, is classified as heavy oil or extremely heavy oil due to its high density and viscosity. Owing to its restricted fluidity and flow capacity, scientists need to come up with a way to elevate it. The majority of scientists use chemical, thermal, and cyclic steam injection methods to recover heavy oil and increase oil recovery. To recover heavy oil, a liquid solution—propane was typically used—was utilized. Liquid propane is the solvent of choice; when injected, it helps raise reservoir pressure by 40–60% through the primary SAGD injection well (Sood & Gupta, 2018).

The industry's reliance on them and the need for petrochemical goods has led to a growth in oil recovery procedures. As a result, low API gravity oil and oil from unconventional sources are extracted in an attempt to make up for any potential production and demand shortfall. There are around 9 trillion barrels of bitumen and heavy oils in the world. The term viscosity refers to a fluid's resistance to flow. As temperature rises, a reduction in this amount causes the mobility value to increase. This fact highlights the importance of thermal enhanced oil recovery (EOR) methods, which include injecting heat generated in situ or at the surface via porous medium using steam or hot water (Ameli et al., 2018). The SAGD technology was created to improve bitumen and heavy oil recovery. Two asymmetrical horizontal wells are dug using this method. High pressure gas is continuously flowing through the top wellbore. The heated oil is pumped out of the lower well and transferred from the top one by this heat, which also reduces the viscosity of the oil. A "steam chamber" is created by the injected steam since heat transfer has taken place throughout this operation. Because they are less dense than oil, steam and other gases build up inside the top well and fill the void left by the oil. Over the steam, the related gas creates an insulating layer. There's no vapor coming from the lower well. Gravity drainage causes an oil and water countercurrent flow in the bottom well. A cavity pump, suitable for viscous fluids with suspended particles, is used to pump this fluid to the surface (Ameli et al., 2018).

It is a well-known fact that oil productions occur mainly in three stages; primary, secondary, and tertiary (EOR). The primary is when the reservoir is drilled and production is mainly from the reservoir's natural energy. As time goes on the natural energy of the reservoir must have been depleted, then a secondary approach, which involves pumping brackish or reservoir water into the well to help produce oil. The secondary technique is only capable of producing 20-30% of the original oil in place. After the secondary method is exhausted, it brings us to the tertiary or EOR which involves injecting substances into the reservoir like steam or chemicals like polymer to reenergize the reservoir (Mokheimer et al., 2018). EOR techniques are normally conducted in two forms thermal/ non-thermal means. Thermal involves lowering the oil physical properties like viscosity and density to enable the oil to be pushed to production wells. Mokheimer et al. (2018) focuses his attention on investigating different techniques that are deployed under thermal EOR. Some of these techniques are cyclic-steam stimulation (CSS) and hot water injection, steam flooding, steam-assisted gravity drainage (SAGD), the aforementioned thermal techniques are the most prominent being investigated.

The world's most valuable petroleum resource is heavy oil, which is mostly extracted via thermally enhanced methods, most notably steam flooding. Many places across the world, such as Lake Maracaibo in Venezuela, the Duri field in Indonesia, the Alberta tar sands in Canada, and the fields in Siberia, Russia, employ steam flooding (Kirmani et al., 2021). Additionally, steam flooding activities are being increased by China, Oman, and California. By continuously injecting steam into the reservoir, a process known as "steam flooding," latent heat is introduced into the reservoir and heavy oil is displaced by vaporization, viscosity reduction, and thermal expansion of rock and fluids. This method also offers progressive recovery as it creates a cold-water bank, which functions as a water drive and forms as a result of a slow drop in temperature. Researchers have evaluated and examined the causes and influencing factors of steam flooding in both light and heavy oils. Steam flooding is connected with a number of significant difficulties, including heat loss, steam override, and low heat conductivity of rock (Kirmani et al., 2021). Steam override reduces the efficiency of steam, which eventually affects oil recovery, by causing adverse displacement of steam advancement, heat loss, and poor heat conductivity. Kirmani et al. (2021) stated that because there is a significant difference in the density and viscosity of heavy oil and steam, the process of steam channeling in steam flooding tends to increase the heterogeneity of the reservoir and decrease its thermal efficiency. Superheated steam's full vaporization and percolation capability result in severe fingering. The mass percentage of the vapor to the liquid phase is known as the steam quality. It is a dimensionless number between 0 and 1 that indicates the amount of water that is turned into steam. The best flooding conditions are determined by a number of factors, including viscosity reduction and steam quality, which also affects displacement efficiency. To control the effect of these viscous fingering, channeling, and gravity overriding, it is very important to control the injection rate and steam parameters. Using an optimum steam quality and injection temperature, and injecting at an optimum rate, plus the simulation time be limited will go a long way to limiting the effect of all the problems outs listed.

Problem Statement

It has been established from literature that about 70% of the world hydrocarbon resources is heavy oil and oil sands reservoirs. It is well known that recovering oil from such reservoirs becomes very difficult due to high content of high molecular weight constituents and Sulphur content. Moreover, in most processing facilities it leads to high operating cost. Due to high cost other conventional EOR techniques are being investigated to see if they can exploit oil commercially. Although, it has been proven that conventional methods can only recover 10-30% of original oil in place from heavy oil reservoirs. Until, today the only technique that has successfully recover oil from heavy oil reservoirs and oil sands is the thermal techniques (Mokheimer et al., 2018). Steam based techniques still hold sway over other method to use to recover heavy oil and oilsands reservoirs. Even though over the years these techniques have entered into exhaustive stages (Dong et al., 2019). There are several problems that affect the deployment of thermal techniques which are; steam rock interaction, steam breakthrough, steam overlap, gravity override, and channeling which makes it very difficult for long term applications. To solve the above problem research has shown that steam flooding is one of the best techniques for recovery heavy oil to reduce dangers of the out listed problems, it is established that high steam injection rate and optimum steam quality will serve the purpose. Several research to select the best method of steam flooding application has been put into place ranging from, well spacing and injection rate, by deploying CMG STARS simulator to model the process in which a recovery of 50-60% is realized (Srochviksit & Maneeintr, 2016). Consequently, most of the recovered oil left behind a lot of residual oil and a way to produce better results of oil recovery factor (above 60%) and cumulative production must be found, which is the purpose of this research thesis.

Research Questions

To better achieve and solve the above problems, the following research questions are to be answered in the course of conducting this research.

1. What is the performance of steam flooding for enhanced oil recovery in comparison to other conventional EOR techniques for recovering heavy oil?
2. Does simultaneous increase or decrease in steam quality, injection temperature, and pressure affects the overall oil recovery factor and cumulative oil production?
3. How does our research numerical simulation perform with respect to other techniques deployed in the same Pelican Lake Field Canada?
4. What is the efficiency of CMG STARS simulator in comparison to other commercial simulators used for similar or same EOR projects?

Aim

This research is aimed at modeling a steam injection process for enhanced oil recovery using CMG STARS simulator software using data obtained from Pelican Lake Field, in Canada, to compute and obtain results like oil recovery factor, cumulative production, and average pressure.

Objectives

To compare the simulation results of our work to those of other methods subsequently used in this oil field (Pelican Lake Field, Canada).

Significance of the Study (Justification)

This research is conducted to test the effectiveness of steam flooding for heavy oil EOR process and application. Since other EOR techniques failed in their bid to recover oil from heavy streams. Hence, the findings from this research would provide the basis for other research in heavy oil recovery, and imploring steam injection. Moreover, it will proper solution to the energy sector in Canada with regards to the viability of the Pelican Lake Field when produced using steam injection. In addition, students of EOR can use the findings and make conclusion on issues relating to simultaneously increasing or decreasing stream attributes (steam quality, injection pressure and temperature) during steam injection, in addition to the contribution it will make to the body of knowledge.

Thesis Structure

The whole thesis is divided into five chapters with each addressing a key task to achieve the overall aim and objectives of the thesis. The first chapter started with a background to the research to provide an insight to EOR processes, types, mode of application, and give specific attention to steam injection. The chapter houses the aim and objectives of the research, the statement of the problem which is the basis of what the research aims to tackle, the research questions or rationale to checkmate our findings, the significance of the research, the scope and limitation of the research to have a headway. The second chapter is the review of literature, which started with the theoretical framework in which concept of the EOR process is introduced with summary of different methods of EOR, theory behind CMG STARS simulator is also given, established facts that relates to numerical simulation is also summarized under the same chapter. Furthermore, the other section of the second chapter contains the related work summary in which summary of different research with relationship to the research topic is highlighted herein. The next chapter is the third chapter which is used to explain the research methodology. Under the research methodology some important sections are the research design to explain the modalities of the research, the population of the research, sampling size and technique, data collection technique, and technique for data analysis were all well explained under the third chapter. Important image attachment was made, process involved in the thesis to enable proper perspective of the thesis. Our fourth chapter is used to present the data used in the conduct of the work and then depicting all important findings, under the findings section some of which are the; oil recovery factor, cumulative production, average pressure etc. At the tail end a detailed explanation of the findings was made under the result discussion heading, rationale to the results obtained is given in a proper perspective. The last chapter discussed is the fifth chapter, in which summary of the research work is given, and then followed up with a sound conclusion and recommendations for future research.

Scopes

Some of the scopes of this research are outlined below;

1. Conduct detailed literature review of related research to come up with trend, pattern, and establish relationship with the research topic.
2. Obtain the needed data from the literature for use as an input to our CMG STARS simulator.
3. Cleaning the data obtained from the Pelican Lake Field, in Canada and then store in an Excel worksheet for onward application.
4. Creating a mechanistic reservoir model of interest using the CMG builder workflow.
5. Inputting necessary reservoir data, array properties, pressures, temperature, and PVT to provide an input for the simulation process.
6. The rock is then created using the rock-fluid add-in on the builder, before setting the initial and numerical conditions of the simulation process.
7. Perforating the reservoir model at a location of interest, here we perforate three wells perpendicular to each other with the producer at the center and two injectors at extreme.
8. The wells operating constraint for both injectors and producer would then be put into place, and the injection fluid attributes as well.
9. The simulation time would be set and then the simulation be run by the STARS simulator, to obtain results.

10. The simulation result file (Sr^3 file) would then be uploaded to the result 3D CMG workflow to compute the following results; recovery factor, water cut, cumulative production, average pressures, production rate etc.
11. Results obtained would be compared to that from established literature.
12. The same process is then replicated for five different scenarios.

Limitations

The study restricted itself to steam injection on data from the Pelican Lake Field in Canada, using CMG STARS simulator, without any requisite laboratory experiment especially on the injected stream. Even though, CMG as a commercial software provided relative efficiency, but lack of real time data will affect it performance. Another limitation is the lack of sufficient time to conduct extensive literature review due to the institutional research timeline.

CHAPTER II
Literature Review

This chapter will tend to focus attention on reviewing past literatures and concept relating to thermal enhanced oil recovery, especially as it relates to steam injection which is the main focus herein. Moreover, other related EOR methods would be reviewed to give us a headway to start the research properly. The chapter is divided into sections to enable us give a proper perspective to the research viz; theoretical concept and related research summary. The technique and brief concept of the CMG software, especially, as it relates to STARS simulator would also be explained in clear terms.

Theoretical Framework

Here the concept and theory of the main research as it gives background to the whole thesis is explained. Most importantly the theory behind numerical reservoir simulation, enhanced oil recovery, thermal EOR techniques, hybrid EOR and lots more. Moreover, little explanation on the CMG software as it relates to STARS simulator is given.

Numerical Reservoir Simulation

Reservoir simulation in a nutshell is the process involving the combination of physics, mathematics and computer programming to develop a tool that would be used to analyze reservoir performance. Essential the process involves both the geological aspect involving the grid formation, Mathematical aspect involving the formation of governing equations and setting relevant boundary conditions, and the use of computer program like the CMG to compute pressure solution. Generally, the mathematical solutions are solved either using numerical or analytical technics, with governing equations mainly in the form of equations or functions (x2, Sin x, ex, etc.) in order to define the analytical solution (Heriot-watt Rsv Simulation, 1997). A sample reservoir simulation model is depicted under Figure 2.1 developed using orthogonal grid approach by Ren & Duncan, (2019).

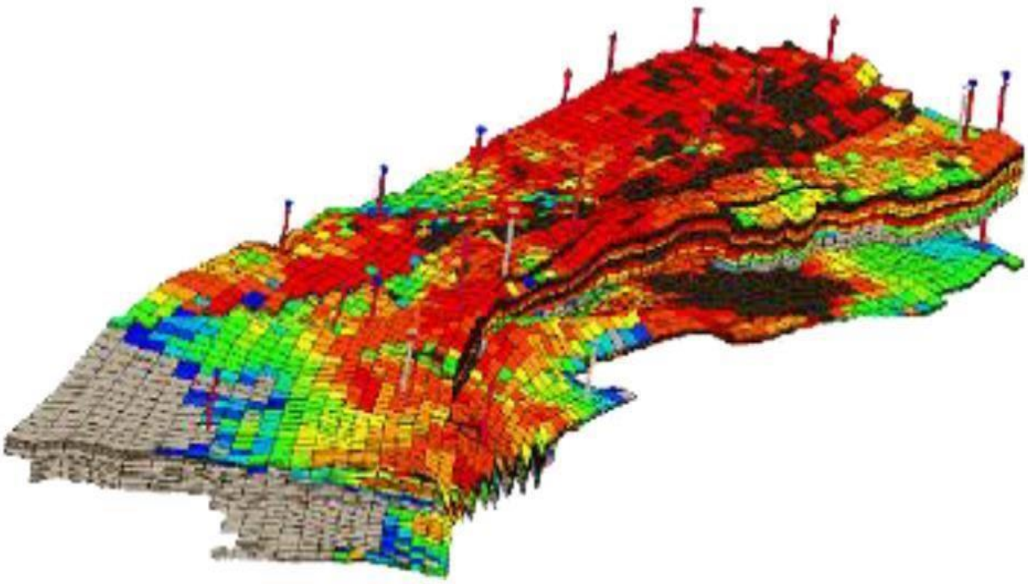

Figure 2.1. Depicting a sample reservoir simulation model (Ren & Duncan, 2019).

Numerical (mathematical) Model. Since, approximations must be made in order to express equations in a way that digital computers can solve with ease, hence, analytical solutions would never be able to solve the reservoirs mathematical equations. Aziz et al. (1979) state that a suitable set of mathematical equations must be used to express the physical system to be described. There are several assumptions made during this procedure. Practically speaking, assumptions are required to keep things stable. For instance, the relative permeability concept has limits that are understood by all reservoir engineers, but we are forced to use it.

Computer Model. A computer model of the reservoir is a software or collection of algorithms created to solve the equations in the numerical model.

In order to build and run a reservoir model effectively, the following actions need to be taken:

- The reservoir and rock property should be entered at an initial stage
- The specific characteristics of the grid's blocks should be inserted (i.e. number of grid blocks, and well control parameters)
- Set up the proper field well controls (such as injection rates and bottom hole pressure constraints) because the model depends on them.

- The output you want to plot may be chosen and saved to a file (you have several options), either for later use or, depending on the situation, even while the simulation is still running.

The output might contain the (partial) list of quantities below:

- The daily, yearly, and cumulative flow rates of gas, water, and oil from each particular well.
- The total field daily output rates for each phase, on a weekly, monthly, and yearly basis: Water, gas, and oil.
- The specific well pressures (lift curves, wellhead, or bottom hole) that vary over time.
- The profiles showing the total field production of oil, gas, and water over time.
- O/W ratios, GORs, and partial or total field water cutbacks throughout time. The time-varying saturations of gas, water, and oil are distributed equally across the reservoir as Sg, So, and Sw (x;y;z;t).
- The average field's pressure versus time

The aforementioned procedures comprise the whole setup and outcome formulation of a simulation model. To create a model that will closely mimic a real-life reservoir condition, mathematical equations, numerical analysis, and computer use are all used.

Background of Enhanced Oil Recovery

Recovery is the key component of the underground oil production process. If it is possible to increase the average worldwide recovery factor from hydrocarbon reserves above current levels, many issues related to the world's energy supply will be resolved. Oil is now produced daily from old or mature oil sources, and the increasing demand for energy is outpacing the replenishment of reserves. For oil reservoirs, the average recovery factor across the globe is presently between 30 and 40 percent. This challenge may be used by cutting-edge secondary for enhancing oil recovery technologies to possibly improve the supply-demand balance. This paper offers a thorough analysis of EOR technologies, highlighting both their benefits and drawbacks (Thomas, 2008). The use of EOR is directly impacted by the state of the economy and the price of oil. EOR is expensive, capital-intensive, and resource-intensive, in large part because injectants are so expensive. Before implementing enhanced oil recovery

(EOR) on a full-field scale, there is a case to be made for advanced secondary recovery, or improved oil recovery, technologies. Another crucial factor is the timing of EOR. The fulfillment of EOR potential may only come from long-term capital and human resource commitments, research and development, a risk-taking mentality, and an ultimate oil recovery aim rather than a rapid oil recovery target. Despite the fact that EOR technology has improved over time, significant challenges remain.

There have been instances where the phrases EOR and IOR have been used casually and interchangeably. The broad concept of increasing oil recovery by all required means is known as "improved oil recovery," or "IOR." Operational techniques include infill drilling and horizontal wells enhance vertical and area sweep to maximize oil recovery. A more restricted definition of improved oil recovery, or EOR, is that it is an IOR subset. A decrease in oil saturation below the residual oil saturation (Sor) is suggested by the EOR. Lowering the oil saturation below Sor may be the only way to recover oils that are held in place by capillary forces (after a waterflood in light oil reservoirs) and oils that are essentially immobile due to high viscosity (heavy oils and tar sands). Since they successfully lessen residual oil saturation, chemical floods, steam-based techniques, and miscible treatments are recognized as EOR procedures (Thomas, 2008). The purpose of EOR varies greatly according on the kind of hydrocarbon. With an average 45% OOIP target, EOR is frequently employed for light oil reservoirs after secondary recovery operations. The predominant source of output from these reservoirs is derived via enhanced oil recovery (EOR) methods, as primary and secondary recovery techniques are not effective for heavy oils and tar sands. The definition of EOR/IOR as illustrated is summarized in Figure 2.2 below.

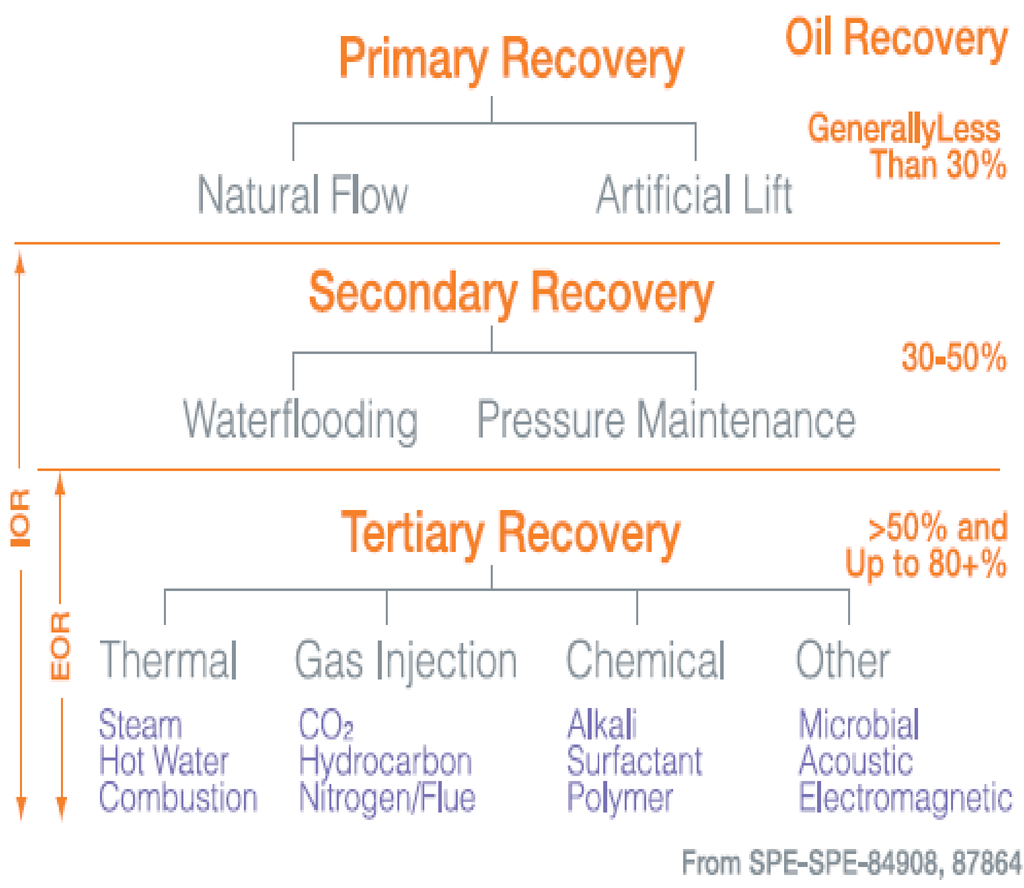

Figure 2.2. Depicting summary enhanced oil recovery process (Thomas, 2008).

The natural progression of oil production from its start to the point at which extracting hydrocarbons from the reservoir is no longer economically viable is succeeded by primary, secondary, and tertiary (EOR) recovery methods. The goal of EOR methods is to recover oil that secondary techniques are unable to recover. Recovery, in particular EOR, has a significant relationship with the oil price as well as the state of the economy overall. Conventional recovery methods (i.e. primary and secondary) recover, on average, around one-third of the original reservoir content worldwide. This implies that two-thirds of the resource base, a key target for EOR, has been established. The recovery factor can be raised by combining best-in-class reservoir management strategies with cutting-edge EOR and IOR technology (Thomas, 2008). We can see many types of hydrocarbon reservoirs and associated EOR targets in Figure 2.3 below.

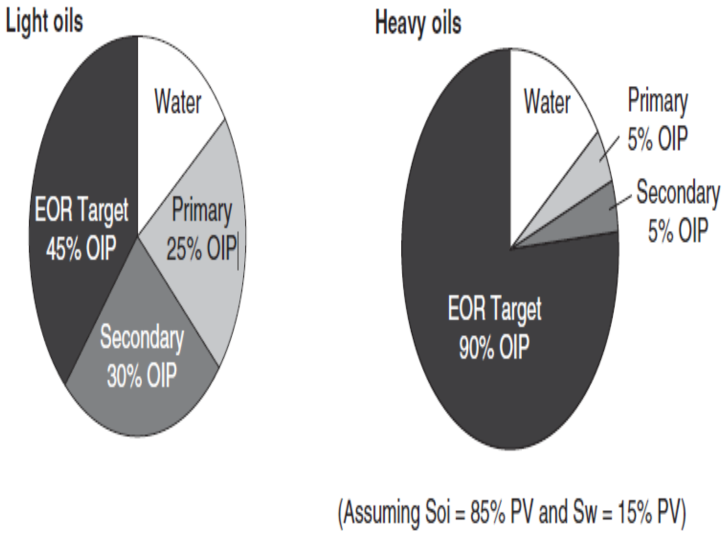

Figure 2.3. Depicting the target of EOR for different hydrocarbons (Thomas, 2008).

Recap of Different EOR Techniques

A brief summary and explanation of some key EOR techniques or methods would be given under these sections. Some of which are; Thermal EOR, Chemical EOR, Miscible EOR, Microbial EOR, and Hybrid EOR.

Thermal EOR

The term thermal EOR is relating EOR method that involves the use of heat (high temperature) to recover hydrocarbon from the sub-surface. Generally, thermal techniques are used to recover highly viscous reservoirs generally referred to as "heavy oil reservoirs". It involves heating the oil through either through injecting hot substances like steam in three different processes; steam injection, cyclic steam simulation (huff and puff), or steam assisted gravity drainage (SAGD) or otherwise through in-situ combustion, hot water injection or electric heating. It is important to note the earlier three means of thermal EOR are the most deployed with successes recorded in different formation or reservoirs over the years. The main ideology of the technique is to reduce oil viscosity, and improving oil mobility and vertical sweep efficiency, thereby recovery more oil. The thermal EOR techniques has up till now remain the most preferred and successful technique for recovery heavy oil. Figure 2.4 below will depict a chart that will show the summary of thermal EOR techniques under each category aforementioned.

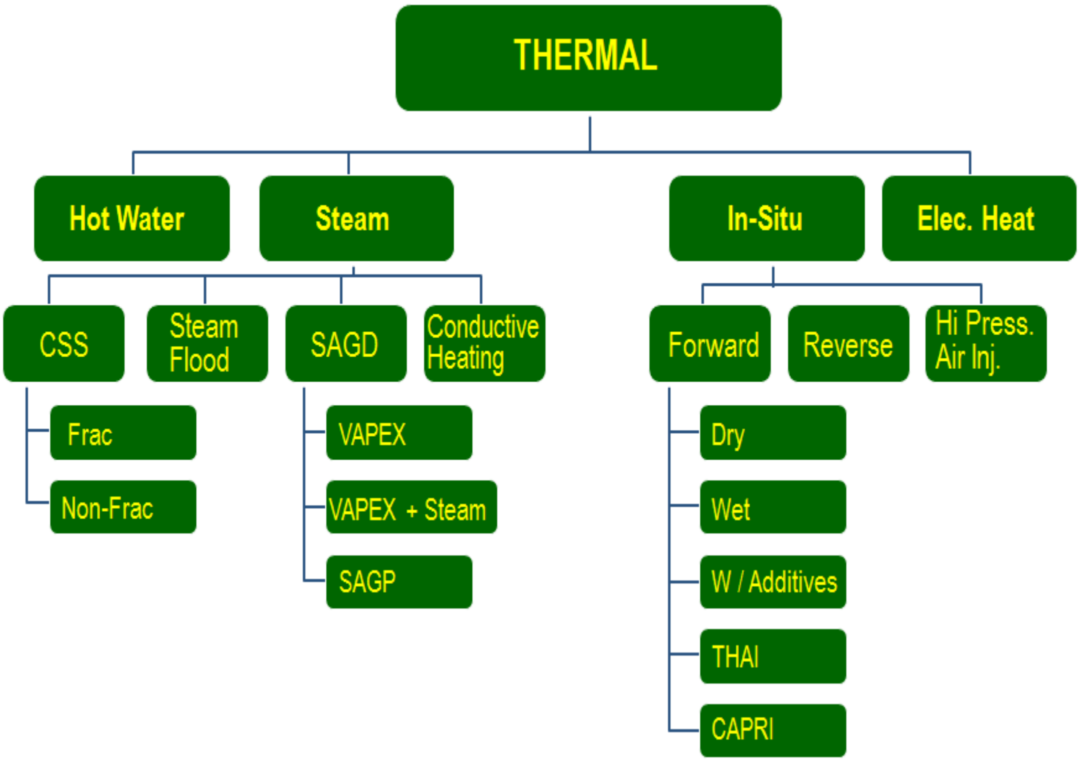

Figure 2.4. Summary Chart of thermal EOR techniques (Guo et al., 2017).

Chemical EOR

Chemical EOR method involves injecting chemical substances like polymer which controls the mobility of the displacing phase (water) and the displaced phase (oil) to a favorable mobility ratio to enable better sweep efficiency. Conversely, other substances like surfactant and Alkalis are used to reduce the water oil interfacial tension, to enable better oil recovery. Nowadays nanoparticles are used in conjunction with one of the above substances for better efficiency. In the 1980s, several initiatives were started, most of them in the US, and a great deal of research and pilot testing was done. Consequently, not a single one of those projects was financially successful. In the past 10 years, chemical EOR—more specifically, polymer—has only been successful in China. The recent increase in oil prices and the success of chemical EOR in China have given it new life. Figure 2.5 below will show the summary of the chemical EOR techniques mentioned above.

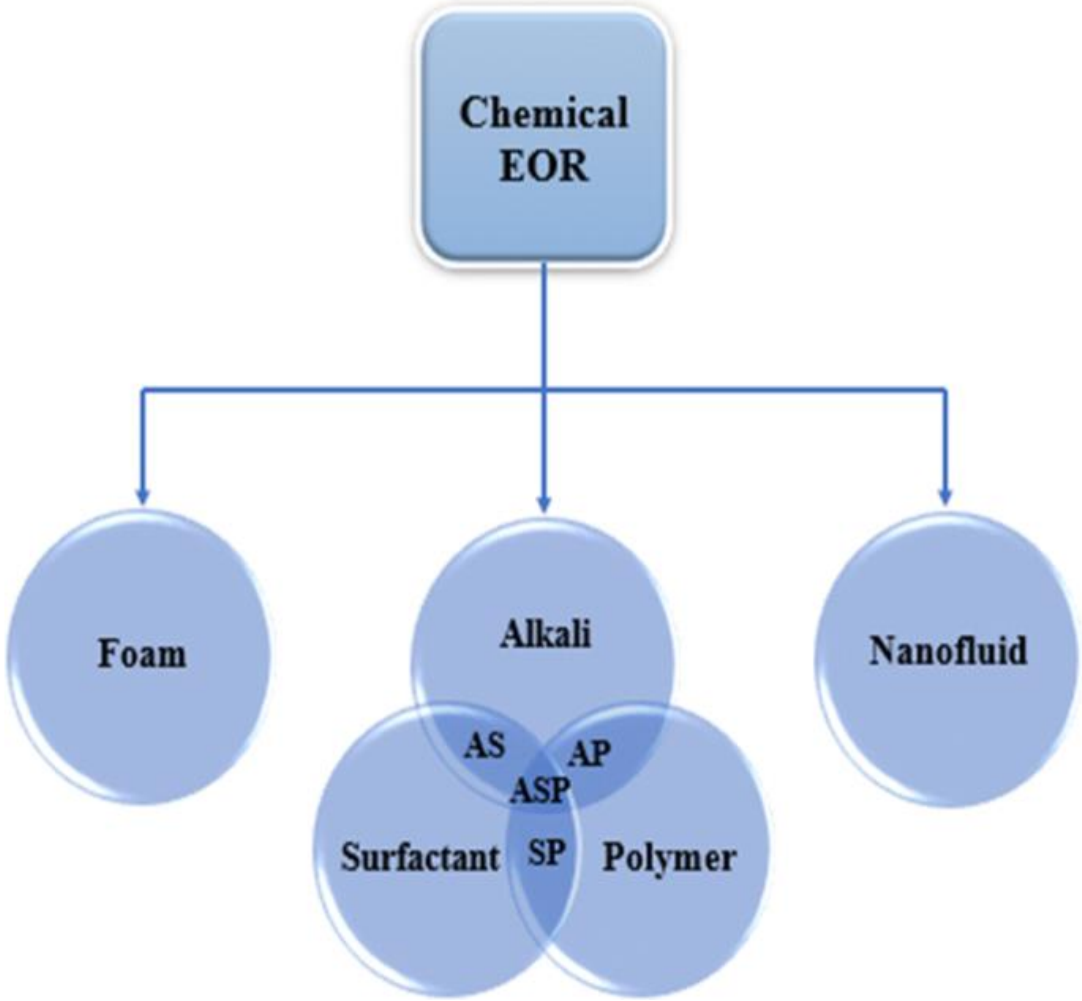

Figure 2.5. Summary Chart of different techniques of chemical EOR method (Holditch, 2004).

Miscible EOR

The miscible EOR is one of the most sought techniques in the oil industry especially gas injection, especially CO_2, which can be favorably injected into both sandstones and carbonates reservoirs to recover light oil. Miscible EOR is expected to become popular as it serves two purposes; 1. Removing greenhouse gases and 2. Enhanced oil recovery through miscibility. There are a lot of successes recorded with CO_2-EOR especially in the Permian Basin in the US where there are over 100 commercial deployments of the CO_2-EOR. Moreover, through same process CO_2 can be sequestrated and stored in depleted reservoir for future utilization (Carbon capture and utilization). Figure 2.6 will depict the technique of the CO_2 miscible process below.

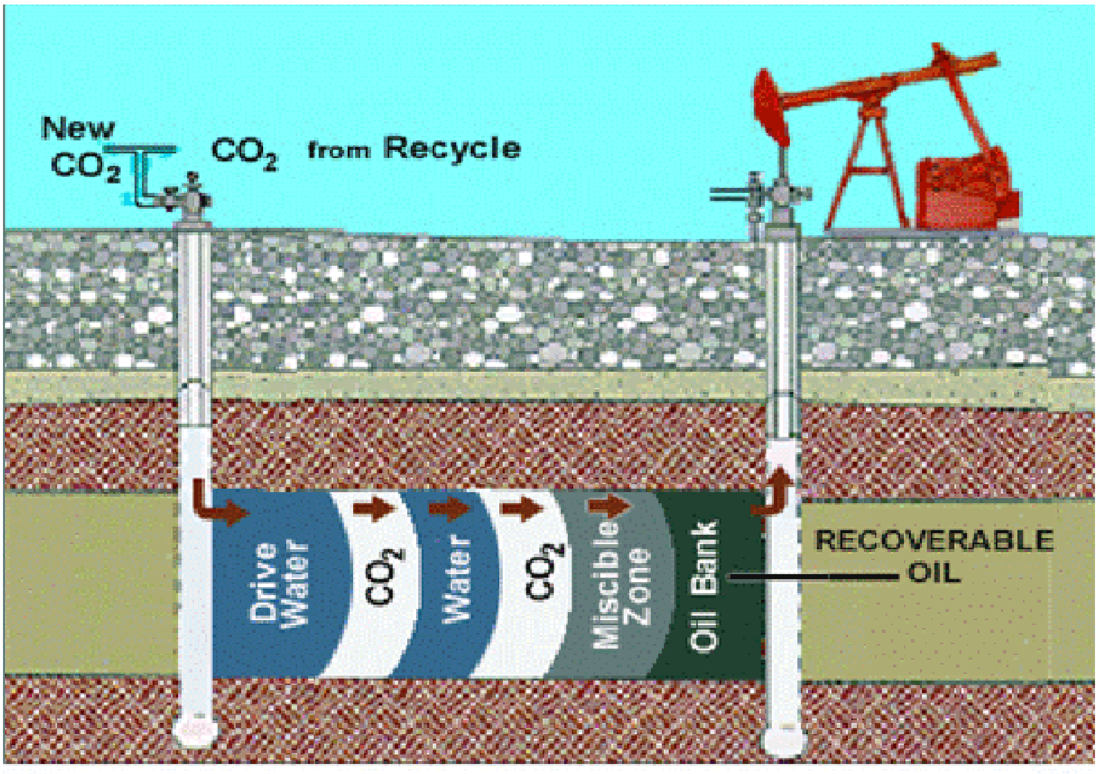

Figure 2.6. Representative diagram of Miscible CO_2 EOR process (Thomas, 2008).

Microbial EOR

This is a novel technique of EOR will relatively less deployment or still at laboratory scale. It involves the use of micro-organisms (bacteria) that can live within the reservoirs and increase oil recovery through their activities and by-products, which as a result forms a stable oil-water emulsion, reduce interfacial tension, and bio-plugging and subsequently diverting the injected fluids into unswept areas in the reservoir.

Hybrid EOR

Hybrid EOR as the name implies, involves the use of two or more of the EOR techniques mentioned above to better produce hydrocarbons from oil reservoirs with minimal repercussions. It is important to note that the application of some of the EOR techniques comes with a lot of difficulty, take thermal techniques; which resulted in steam rock interaction, gravity override, all would be solve if in use with a technique such as miscible CO_2. Researchers are now diverting their attention to investigate more hybrid EOR techniques that can produce more oil, with high efficiency, safety of deployment, and economical.

Cmg STARS Simulator

In CMG's advanced processes reservoir model, known as STARS, features such as chemical, advance flooding, dual-porosity, horizontal wells, dual permeability, flexible wells, and much more are offered. STARS was created to replicate a variety of chemical additive processes, including steam flood, dry and wet combustion, and many more, using a variety of grid and porosity models at both field and laboratory scales. The three-phase, multicomponent, steam and heat additive simulator is referred to as STARS. Systems of grids might be spherical, cartesian, or have different thicknesses and depths. Any of these grid systems can be configured in two or three dimensions. STARS creates three more files after utilizing the first data set you generate. Three files are produced by each STARS run: a text output file, an SR2 index file, and an SR2 main file. Figure 2.7 illustrates the input and output control mechanism of the CMG STARS simulator.

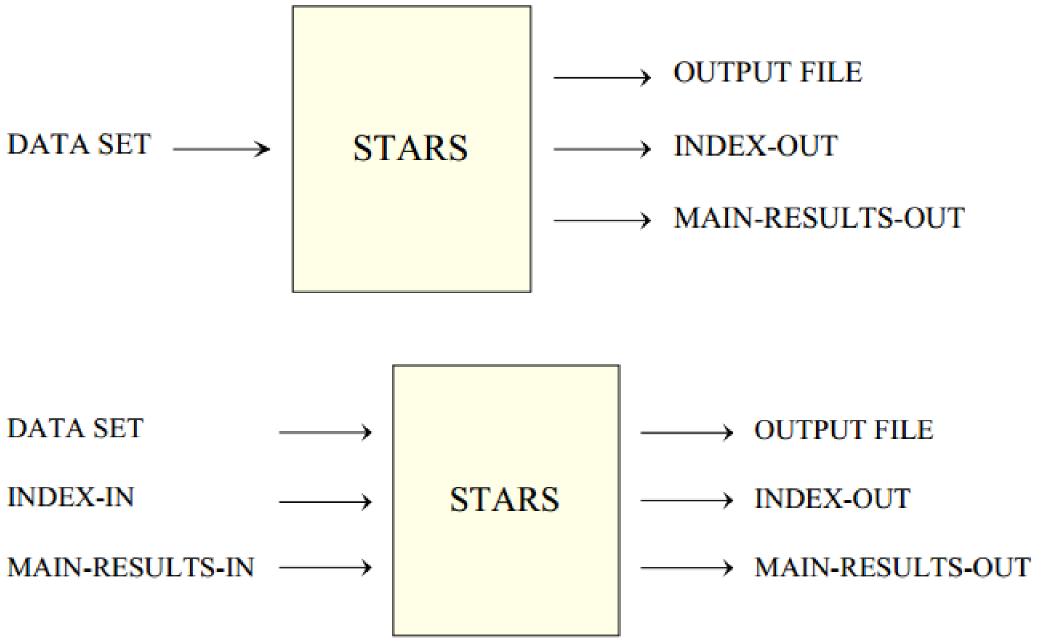

Figure 2.7. Set up of input and output of STARS (STARS User Guide Coflow, 2021).

Related Research Summary

Under this section which is the second component of the literature review, related researches would be dissected and summarized to give a proper backing and background to this research. Some of the related researches are; hybrid EOR, thermal EOR, and other research involving numerical simulation or the use of CMG software.

A thorough analysis of enhanced oil recovery (EOR) methods that may be used during the post-steam injection stage was provided in a research article by Dong et al. (2019) titled "Enhanced Oil Recovery Techniques for Heavy Oil and Oilsands Reservoirs After Steam Injection." The majority of the techniques examined include thermal solvent processing, in-situ combustion, thermal non-condensable gases (NCGs) (such as air, flue gas, and N2), and thermal chemical (such as polymer, foam, and surfactant) processes. Steam based techniques still hold sway over other method to use to recover heavy oil and oilsands reservoirs. Even though over the years these techniques have entered into exhaustive stages. Due to steam rock interaction and gravity overriding, it becomes eminent to deploy new techniques capable of addressing this menace. The review findings by Dong et al. (2019) showed offshore oil fields as future oil exploitation destination. In Emeruade field Congo and Bohai Bay in China some of this steam-based techniques and thermal-NCG are being deployed. His review focuses attention on bringing out novel techniques capable of recovery heavy oil fields. Several techniques like the electrical method, in-situ upgrading is still at laboratory experimental stages. In some fields in the United States of America several techniques like thermal fluids injection, thermal-CO_2 and thermal chemical are also used in offshore heavy oil fields and have yielded positive results.

Research was conducted by Guevara et al. (2018) to optimize reward learning-based steam injection for heavy oil reservoirs. It is evident that finding the right or optimal injection rate during steam injection becomes a bottleneck especially when injecting at a constant rate for a prolonged period of time. The optimal steam injection strategy of course becomes an essential thing to investigate due to challenges of complex dynamic physical phenomenon, i.e. high order, slow, non-linear, and potentially highly heterogeneous reservoirs. To solve the above out listed problems Guevara et al. (2018) deployed a model-predictive control (MPC) strategy and adjoint state optimization for developing an optimal control strategy (policy). In order to treat the mathematical model of the dynamic process (SAGD) as unknown, a reinforcement learning (RL) technique is applied. After then, via repeated interactions with the component environment, an agent is trained to choose the best course of action. Each time the agent uses a time step to carry out an action (such as reducing the rate of steam injection), it gets rewarded and displays the updated pressure distribution state. This executed action is repeated over multiple simulations to obtain and maximize total future reward, until convergence is achieved. Guevara et al. (2018) deployed the state-action-reward-state-action (SARSA) for implementing the above strategy. The online policy method, which is applied at each time step and then used to select the best course of action, is continuously used to estimate the action value function. A reservoir simulation that was developed using data from a specific reservoir in northern Alberta serves as the environment. The model is estimated to produce for 250 days and consists of a single well pair (one producer and one injector). The model is evaluated for every time step and is used to provide values for cumulative oil, water production, and water injection. Using a stochastic gradient to approximate the action-value function, the actions taken into consideration are increasing or decreasing the injection rate, and the Net Present Value is the reward. According to the results, the best steam injection policy with RL implementation increases the net present value (NPV) by at least 30% while requiring less computation—more than 60%.

Research conducted by Kirmani et al. (2020) in which he analyzes performance of steam flooding performance using simulation with the help of eclipse software for modeling. It is well-known fact that in recent years heavy oil reservoirs are well targeted and the methods that have proven effective in this regard is the thermal based EOR techniques. Most notably steam flooding is deployed in order to unlock the high oil viscosity of heavy oil and thereby improving its mobility. Numerous investigations by were carried out on how to improve steam flooding efficiency from heavy oil reservoirs, it has been concluded that high steam flooding is the best approach. Findings by Kirmani et al. (2020) shown that high injection temperature and a moderate (optimum) steam quality yielded the best results in terms of oil recovery in a more economical fashion.

A review by Mokheimer et al. (2018) on thermal enhanced oil recovery techniques evaluation. Some of the techniques are cyclic-steam stimulation (CSS) and hot water injection, steam flooding, steam-assisted gravity drainage (SAGD), the aforementioned thermal techniques are the most prominent being investigated. It is a well-known fact that oil productions occur mainly in three stages; primary, secondary, and tertiary (EOR).

Aziz et al. (2023) examined the effects of water flooding and polymer flooding on reservoir performance using a three-dimensional water-and-oil model and a black-oil simulator. In the oil and gas industry several techniques can be deployed to recover hydrocarbon from the sub-surface of a reservoir. Particularly, water flooding is employed as a conventional method, which can recover at least 10-40% of the oil in place. Polymer flooding involves the injection of polymer into the reservoir to increase water viscosity and hence, improve the viscosity of injected fluid to reservoir fluid to a more favorable value. As thus, vertical sweep efficiency is improved with polymer when compared to conventional water flooding. The performance of the reservoir is merited from results such as; production rates, water cut, cumulative outputs, and oil recovery parameters. Results from both methods were then compared in order to design the solution, which is a bio-polymer as xanthan gum is added to the water and then pumped into the heterogeneous unconsolidated reservoir via a direct line drive. A sensitivity analysis was performed on the polymer flood using a five-point spot injection pattern in order to optimize and evaluate well injection schemes. The findings of Aziz et al. (2023) show a recovery factor of 44% by direct-line drive polymer flooding as oppose to the 52% obtained by five-spot pattern. Furthermore, during the five-spot pattern, a considerable delay in water cut is noticed over time. Therefore, it is more efficient and appropriate to deploy the five-spot pattern with polymer flooding in order to extract more oil from the reservoir that is being studied.

To test the economic viability of the field, the field operator of the Canadian Natural Resources Limited was requested to allow the Pelican Lake Field to be simulated using scenarios and methods of enhance oil recovery in order to test the economic viability of the field. Delazeri and Lamas (2021) simulated five (5) scenarios of fluid injection using Puma flow software on different polymer and surfactant injection into injection water. To aid oil bank mobility and lower interfacial tensions, it has been observed that surfactant concentrations was the major factor that influence key characteristics that aid in good oil recovery. The findings of Delazeri and Lamas

(2021) shows that oil recovery is directly proportional to the concentration of the chemical agents. Net present value is use to evaluate the suitability and performance of each scenario. The best scenario for which a 1400 ppm concentration polymer is used and a 3000-ppm surfactant concentration in injected water shows a 50% higher net present value when compared to water injection case, and a percentage increase in the recovery factor points of 4.85. The research has proven to be cost effective solution to oil production since only 8.18 USD is spent on chemical agent for every barrel of oil produced.

Hu et al. (2020) in his paper in order to measure cumulative oil production investigated different foam injected and salinity brines like NaCl, $CaCl_2$, KCl, and $MgCl_2$. It is a well-known fact that foam stability is one of the major problems faced during foam injection. His result shows that sequential low-salinity water injections with KCl and foam flooding yielded the best result in terms of cumulative oil production in sandstone reservoirs. The success of the best case is due to the high wettability observed with KCl. Since, K+ is a monovalent cation, KCl has the highest wettability changes when compared to other saline brines and formation water at 1000 ppm. Moreover, the injection of foam after KCl brine injection yielded an overall oil recovery factor of 63.14%, when compared to $MgCl_2$ with 41.21% and formation brine with 36.51%, which is the maximum result in this research. Hence, KCl brine injection should best be used before injecting foam (Hu et al. ,2020).

The knowledge of fluid flow in a porous medium gives essential information on how to extract adequate liquid from the subsurface. In this research Hu et al. (2020) focuses attention on using different injectivity scenarios ranging from chemical and thermal methods to compare the efficiency of each method in terms of oil recovery enhancement. Result of the recent research shows a maximum oil recovery of 80% with foams and brine injections. Conversely, it is 66% for brine-carbon dioxide and 58% for brine-nitrogen accordingly. Hence, foam injection after water flooding is the most effective method in order to produce more oil from tight reservoirs.

It is well established that steam injection is a majorly used technique for heavy oil production. Steam injection rate is directly proportional to its ability to exploit heavy oil. Guo et al. (2017) selects a two-dimensional symmetry model and, using a VOF model of steam injection wells, analyzes various parameters, such as the wellbore parameters during steam injection in horizontal wells and the effects of changes in single and dual steam injection, as well as the injection pipe string structure in the vertical well section during the steam injection period. The outcome indicates that, in comparison to using horizontal pipe steam injection, vertical well steam injection using high vacuum insulated tubing reduces the dryness of the steam, which is beneficial to the balanced growth of heavy oil.

Then, by simulating reservoir conditions during steam injection, a unique technique for producing heavy oil emulsion is identified. The efficacy of the approach is evaluated using measurements of the IFT and rheology. Mechanical stirring is less successful than steam injection approaches in producing emulsions under reservoir circumstances, while appearing to provide superior outcomes when comparing its water content (Mohammed et al., 2020). The flow of foamy oil and the driving mechanisms employed in foam-based heavy oil recovery approaches are highlighted by (Basilio & Babadagli, 2020). In addition to highlighting the durability of foamy oil, cyclic steam injection and foam for heavy oil recovery are contrasted (CSI). The method is applied in empirical studies of the mechanisms behind the behavior of the foam phase generated by methane. Gravity is the main component that separates methane that dissolves as a gas in the oil phase from that which dissolve in the foam. Three conclusions were drawn from the study's findings. Second, CSI benefits from reservoirs with good permeability. Utilizing the soaking time as the only operational injection pressure is not recommended.

In order to increase the steam injection rate for shallow heavy oil reservoirs, Huang et al. (2020) carried out an analysis. They use a computation model for different sweep distributions as the basis for their investigation. Zones having more than fifty (50) distributions in the oil saturation sweep analysis are referred to be erroneous injection zones. The results demonstrate that a change in steam injection rate has no effect on the ideal steal quality in the steam chamber after analyzing the effects of each injection parameter. Nonetheless, the rate of steam injection throughout the manufacturing process has a direct impact on the actual steam quality in the steam chamber of the reservoir. As a result, by comparing the value of the actual steam quality in the steam chamber with the real steam quality in the steam chamber, the current steam injection rate may be calculated. It is shown that the ideal steam quality in the steam chamber is significantly influenced by the injection time. The range of typical injection variables, between 0.1 and 0.3, is in line with the steam chamber's ideal steam quality.

Heavy oil resources are the future target and major hydrocarbon resources. Although, due to its high viscosity steam flooding (SF) is deemed as the best method to exploit it, hence, several investigations were made to investigate the best way of applying it, ranging from varying well spacing and steam injection rates. Srochviksit and Maneeintr (2016) his research investigated the effect of well spacing, injection rate, and perforation on heavy oil production with low permeability in a multi-layered heterogeneous reservoir. STARS simulator, a CMG software program is used to model the steam flooding process by applying practical field data. 80% Steam quality is used for an injection rate ranging from 30 m^3/d to 180 m^3/d and well spacing between 141 m to 282 m in order to find the optimum conditions. The simulation process was set to run for 20 years production. Result of the research shows that higher oil recovery can be achieved by shortening well-spacing and increasing injection rate. To minimize steam consumption, selective perforations in the bottom layer is compared with full perforation strategy. Balancing steam injection and oil production, saving about 60% of steam in terms of water barrels (bbls). Since, there is low depletion rate experienced, it is possible to achieve a longer project period.

Summary of the Literature Review

In essence, different concept and theories as to how and why thermal EOR is applied to heavy oil reservoirs has been explained in clear terms. Moreso, connection between past and emerging techniques used the hydrocarbon sector has been well established. Different scientist has justified concept that are intertwine to one another has shown clearly different applicability of the thermal based techniques used for EOR in the industry. Moreover, the concept of numerical reservoir simulation and modeling has been established as it relates to the use of different software’s as the CMG, the STARS simulator workflow is also shown, detailed summary of EOR methods is also given under this chapter.

CHAPTER III
Methodology

This section will explain the Methodology of the thesis in areas of study population, study design, sampling techniques, method of data collection, sample size, data analysis techniques, reliability and validity. Moreover, the most important aspect of the work which is the model, would be extensively explained herein. In addition, the Builder, which is where all model constructions are done with the CMG software would be elaborated through its individual sections viz; component section. At the tail end the mathematical/numerical governing equations would be shown, to appropriate describe the fluid flow behavior.

Research Design

The design of this research is achieved using a Pre-processing software called The Builder, which is one of the component sections of the CMG software. A single porosity model is allocated to a structural reservoir model using the Builder. In order to achieve the design of interest, each section of the Builder is populated with the relevant data, to achieve desired model of interest.

Study Population

The study population in this research is consisting of a $15 \times 15 \times 5$ grid in the IJK direction respectively, making a total of 1125 grid blocks. The number of layers is represented by the K direction which is (5), telling us that the model is consisting of 5 layers in totality. It is of our interest that we represent the EOR process via two injecting wells and one producer all perpendicular to each other, with the producer being at the center of the two injectors for better sweep efficiency. The same operating constraint is use although with little variation, pressure analysis and other results are analyzed using the result 3D.

Sampling size and Techniques

Six different models were constructed alternately and the techniques deployed for analysis is the stratified sampling. Our decision is based on the fact that, data is not collected through physical observations, or interviews, but through numerical simulation.

$$S = \frac{T}{E} \times P \tag{3.1}$$

Where;

P= Population of sub-group

T= Total sample size

E= Entire Population

S= Stratified random sampling

Method of Data Collection

The data collection method adopted here is through the review of related research, work by other colleagues, and models related. The resulting data from the Pelican Lake Field in Canada is then collected and stored using Microsoft Excel and preliminary data cleaning and processing were also done using related analysis software. However, the primary data source for the research thesis is the CMG software, which is our software of interest.

Procedure for Data Analysis

The analysis would be carried out on the .Out file, the acronym ". Out" signifying output data file, obtained after the simulation process. The file is mounted on the CMG CEdit add-on, while the fluid data is analyzed using CMG WinProp software. The generated simulation result will undergo descriptive statistical analysis as follows;

- Maximum and Minimum Values
- Skewness, kurtosis, mean, and standard deviation

Validity and Reliability Criteria

Since we depended on empirical data for the model construction, there is a need to validate our model after construction. The reliability of the STARS simulator in comparison to other commercial simulators would be made. The model validation is also done using the STARS simulator.

Model Overview

The model under consideration is a homogeneous non-fractured, slightly compressible water-wet reservoir that is used for pure steam injection. Prior to initiating the Builder graphical user interphase; the date for initiating the simulation, the type of unit system to be adopted, and the porosity model, are all selected. After, the aforementioned selections are made, you can then choose to initiate your Builder software which will be deployed extensively for the success of this these, in which case, all its section would be populated with relevant data. The simulation is set to run for 10 years, in order to obtain recovery factor, cumulative oil, average pressure etc. The same grid model, component, rock and fluid, wells and recurrent were used to run six different models, the first being a no injection while the remaining were used to inject pure steam with varying stream attributes (i.e., steam quality, steam injection pressure, and temperature). The components of the Builder are as follows;

- ✓ Input/ output control
- ✓ Reservoir section
- ✓ Component section
- ✓ Rock fluid section
- ✓ Initial conditions
- ✓ Numerical
- ✓ Wells and recurrent section

Each of the section above would be populated with relevant data to obtain a model of interest, to run and validate simulations of interest. The standard model of interest most contain geological, mathematical, numerical, and computer algorithm. The formation of the steam injection model(s) as it relates to the above builder section would be explained below;

Design of the Steam Injection Model using STARS Simulator

The models are constructed using the Builder software by deploying STARS as a simulator of interest, the first model to be constructed is the no injection (base) model, thereafter, the remaining models were then constructed to inject pure steam. Brief and detailed explanation where necessary would be made on each section of the Builder as it is used for this thesis.

Reservoir Section

The first thing to be done is to construct our grid system otherwise known as the reservoir model, and then assign relevant array properties data to it. The grid is a 15 ×15 × 5 model representing the IJK directions respectively making it a total of 1125 grids. In both the I and J directions each of the grid block is having a width of 22 ft i.e. 15 × 22 ft. The 5 grids in the K direction represent the number of layers. After creating the grid using the above input Figure 3.1 is obtained as depicted below.

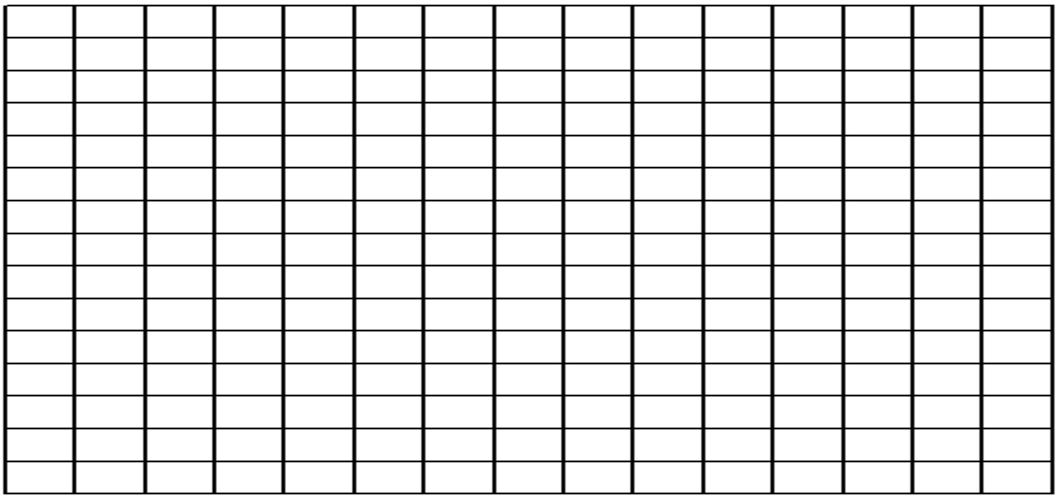

Figure 3.1. 2D areal view of the grid without array properties assigned.

Figure 3.1 is empty without prerequisite assigned array and petrophysical (porosity, permeability) properties. Some of the important array properties includes (grid thickness, compressibility, reservoir temperature and pressure). In this thesis our first layer which is chosen as the reference is set at 1500 ft, the grid thickness is chosen to be 10ft. The porosity of 30% is selected for the model and a permeability of 500mD in both the I and J-direction, and on the contrary 50mD in the K-direction due to overburden. After assigning the petrophysical properties the resulting grid system is obtained in 3D, Figure 3.2. will show the resulting grid system in 3D below.

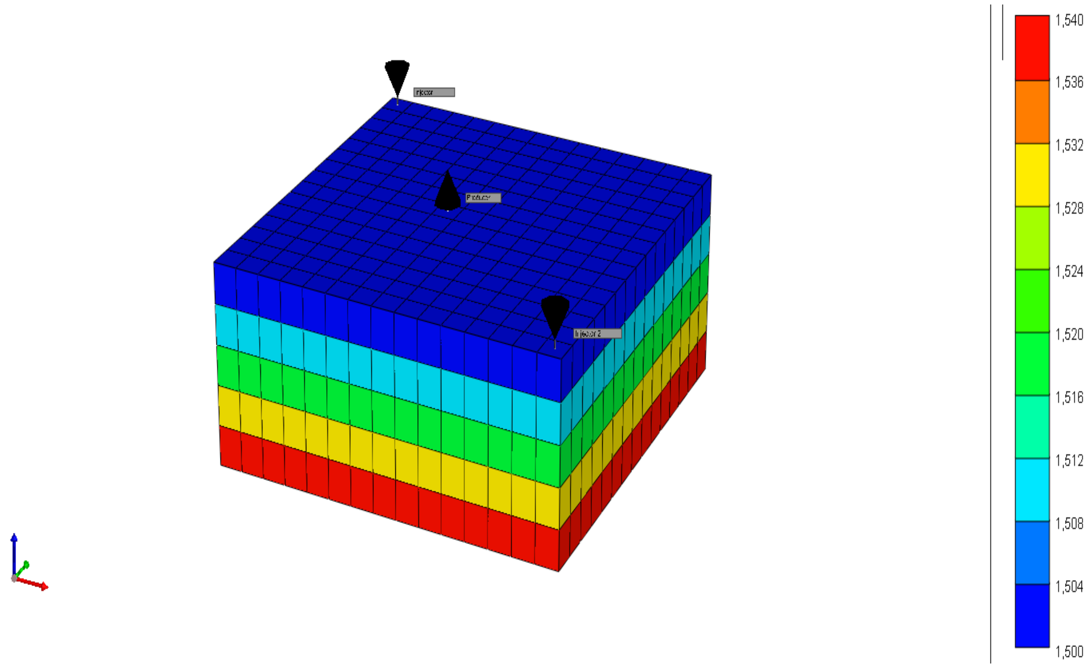

Figure 3.2. Resulting grid sytem in 3D populated with Petrophysical data.

Having added the required petrophysical data the next task is to aasign the reservor temperature and presure, and for this model a temperature of 200 °F and a pressure of 400 Psi is assigned as in the data set.

Component Section

The component section is one of the key sections of the Builder software, it is where the fluid properties of PVT data are assigned and generated. The important aspects in the componet section is to define and add the components, assign viscosity and other relevant data. Since, we are injecting pure steam, the components to be added are water, and the heavy oil. In order to add our component the critical pressure, temperature, and molecular weight of both water and heavy oil were added accordingly. The critical pressure of water being 3208.23 Psi, and that of heavy oil is 149.65 Psi. The critical temperature of water 705.182 °F with a molecular weight of 18.015 lb/lbmole, and that of heavy oil as 1107.81 °F and molecular weight of 378.93 lb/lbmole. After adding the critical properties and molecular weight, the next is to define the viscosity parameters. To define the liquid phase density we change molar density of both water and heavy oil to mass densities and inputed the values of 62.4 lb/ft^3 and 55 lb/ft^3 for water and heavy oil respectively. In addition, to input the liquid phase viscosities we defaulted BVISC and for the AVISC the values of 0.5 and 1 were added for water and heavy oil respectively. Lastly, the reference conditions which is a temperature of 200 °F and a presure of 14.7 Psi were added at the general section drop down, after completing all the above we now apply and end the component section, and hence, the components are added.

Rock and Fluid Section

The rock and fluid is where we select the type of rock and relative permeability to deploy, for CMG software you can apply correlation or input laboratory finding. For this case we decide to work with correlation and input the following constants contained in Table 3.1. below.

Table 3.1. *Rock and Fluid data Table.*

Correlation Coefficients	Value
SWCON	0.25
SWCRIT	0.25
SOIRW	0.22
SORW	0.22
SOIRG	0.3
SORG	0.3
SGCON	0
SGCRIT	0.05
KROCW	0.9
KRWIRO	0.3
KRGCL	0.3
Exponent for KRWIRO	2
Exponent for KROCW	3
Exponent for KROGCG	3
Exponent for KRGCL	3

When the above constant are applied a resulting rock and fluid section is complete and relative permeability data is generated as a consequence.

Initial and Numerical Conditions

The initial condition is one of the most important section of Builder and it is initiated immediately the rock fluid section is conpleted, inorder to set the beginning or the initial state of the reservoir. Here for easy computaation and since we don't have any transition zone we selected the VERTICAL OFF calculation method. It is a well known fact that simulation cannot be carried out without defining its numerical conditions, which includes; the calculation method, iteration, time step size and what have you. Here, we selected a time step size (DTWELL) of 0.001 day, and linear solver iteration and linear solver orthogonization to be 150, after turning our isothermal on, and changing our maximum average residual to be TIGHT. The model covergence tolerance is maximum residual, after setting the adequate initial and numerical conditions to only section left out is the wells and recurrent.

Wells and Recurrent

The time frame for running our simulation is 10 years, and the model is consiting of two injectors (I_1 & I_2) and one producer at their center, with each well at equi-distance and parallel to one another. Essentially, six different models were generated, the first being the no injection consist only of a production well, and its operating constraint are as follows; a minimum bottom hole pressure of 2000 psia, and surface oil rate of 4000 bbl/day. After applying the aforementioned constraint the simution time is then set as 10 years and then the simulation is submitted for STARS to run, validate, and generate result where necessary. Conversely, the other five models involving injection constraint are modelled as follows. A first or normal injection is initiated and thereafter being replicated, except for the changing stream attributes. The injections constraint used for both I_1 & I_2 are the same for all the models as follows; Maximum bottom hole pressure of 8000 psia, and surface gas rate of 2000000 ft^3/day in order to inject steam. The same operating constraint is used for all the model producer (no injection, first injection through fifth injection). The first normal injection we use optimum stream attributes with; 6000 psia injection pressure, 600 °F temperature, and 0.75 quality steam. Thereafter, the next two models we increase the values of our attributes, and the last two we decrease in order to make result comparisons. To ramp up, each model was set to run for 10 years, and then submitted to STARS simulator to run, generate result and validate.

Numerical (mathematical) Model

The numerical model is the last crucial element for reservoir modeling and simulation, after the computer software and geological model. The geological model is the one that was produced by means of computer software and algorithms, namely CMG in this instance, as was previously explained in the procedure. The mathematical model includes mass conservation, flow equations, and methods for solving them. Examine an elemental control volume, as illustrated in Figure 3.5 below, for both inward and outward mass flow.

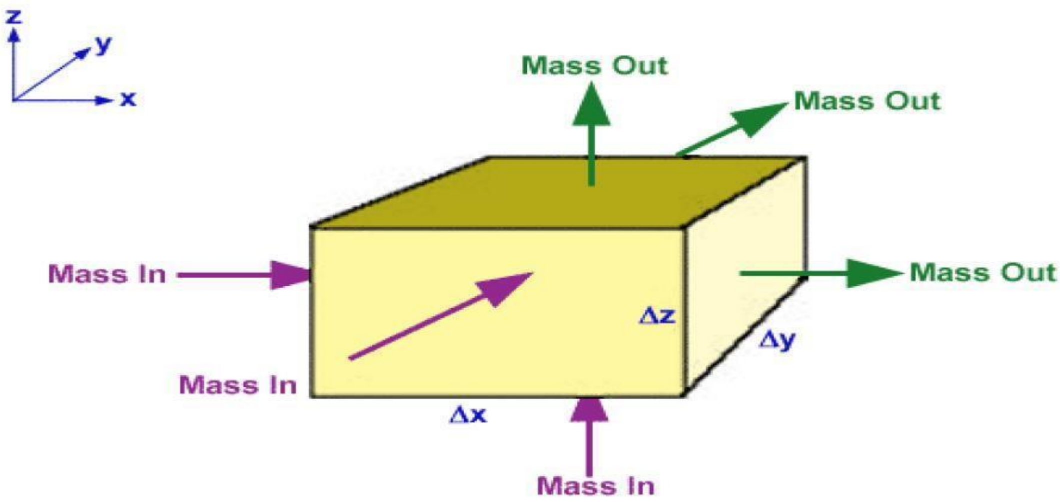

Figure 3.3. Showing 3D control elemental volume for the mathematical modeling

Conservation of Mass Equations

The mass conservation principle is as follows;

$$[Mass\ in] - [Mass\ out] + [Source/Sink] = [Mass\ accumulated/depleted] \qquad (3.2)$$

Source/sink=Injection (IN (+)) or Production (OUT (-))

Mass rate:

$$m_{f,x} = q\rho_{f,x} \qquad (3.3)$$

$$\left[\left(m_f\right)_x \Delta t\right] - \left[\left(m_f\right)_{x+\Delta x} \Delta t\right] + Q_f^* \Delta t = \left[\Delta x \Delta y \Delta z \left(\emptyset S_f \rho_f\right)_{t+\Delta t} - \Delta x \Delta y \Delta z \left(\emptyset S_f \rho_f\right)_t\right] \qquad (3.4)$$

Let $$m_{f,x} = m_{f,x}^* \Delta y \Delta z = m_{f,x}^* A_x = \rho_f V_{f,x} A_x \qquad (3.5)$$

$$\rightarrow \left[\left(\rho_f V_{f,x} A_x\right)_{x+\Delta x} - \left(\rho_f V_{f,x} A_x\right)_x\right] + Q_f^* = \frac{V_b\left(\left(\emptyset S_f \rho_f\right)_{t+\Delta t} - \left(\emptyset S_f \rho_f\right)_t\right)}{\Delta t} \qquad (3.6)$$

Where;

q = flow rate, in ft^3/day

ρ = fluid density, lb/ft^3

$m_{f,x}$ = fluid mass rate, lb/day

f ,x = fluid phase in terms of x

$\emptyset$ = Porosity

S = saturation, A = Area

Vb = bulk volume

$m_{f,x}^*$ = mass flux, which is product of the fluid density and velocity, in lb/ft2*day

Vf = velocity of the fluid phase, ft/day

Q_f^* = mass flow rate of well, lb/day

Dividing Eq. 3.3 by the bulk volume Vb and recall;

$$\left[\frac{\partial f}{\partial x} = \lim_{x\to 0} \frac{f(x+\Delta x) - f(x)}{\Delta x}\right]$$

Take the limit as Δx, Δt → 0

$$-\frac{\partial}{\partial x}\left(\rho_f V_{f,x}\right) + \frac{Q_f^*}{V_b} = \frac{\partial}{\partial t}\left(\emptyset S_f \rho_f\right) \qquad (3.7)$$

Multiplying equation 3.7 by Vb resulted to;

$$-\frac{\partial}{\partial x}\left(\rho_f V_{f,x} A_x\right)\Delta x + Q_f^* = V_b \frac{\partial}{\partial t}\left(\emptyset S_f \rho_f\right) \qquad (3.8)$$

$A_x = \Delta y \Delta z$

Convert Q_f^* volumetric flow rate as;

$Q^*(lb/day) = q_{fsc}(STB/day) \cdot \rho_{fsc}(lb/SCF) \cdot 5.615(SCF/STB)$

Equation 3.8 is the general form of the continuity equation for any kind of phase

For oil: $-\frac{\partial}{\partial x}\left(\rho_o V_{0,x} A_x\right)\Delta x + Q_o^* = V_b \frac{\partial}{\partial t}(\emptyset S_o \rho_o)$

For water: $-\frac{\partial}{\partial x}\left(\rho_w V_{w,x} A_x\right)\Delta x + Q_w^* = V_b \frac{\partial}{\partial t}(\emptyset S_w \rho_w)$

For gas: $-\frac{\partial}{\partial x}\left(\rho_g V_{g,x} A_x\right)\Delta x + Q_g^* = V_b \frac{\partial}{\partial t}\left(\emptyset S_g \rho_g\right)$

We can introduce formation volume factor $\rightarrow B_f = \frac{\rho_{fsc}}{\rho_f}\ in\, rb/STB$ in terms of the phase density as;

$$\rho_f = \frac{\rho_{fsc}}{B_f} \qquad (3.9)$$

Flow Equations

In order to adequately model the flow equation, we must introduce the Darcy law equation;

$$V_{f,x} = -5.615 \frac{K_x K_{rf}}{\mu_f} \frac{\partial \Phi_f}{\partial x} \tag{3.10}$$

Substituting Eq. 3.10, ρ_f, Q_f^* into Eq. 3.8

$$\frac{\partial}{\partial x}\left(\frac{\rho_{fsc}}{B_f} 5.615 \frac{A_x K_x K_{rf}}{\mu_f} \frac{\partial \Phi_f}{\partial x}\right)\Delta x + q_{fsc}\rho_{fsc}(5.615) = V_b \frac{\partial}{\partial t}\left(\emptyset S_f \frac{\rho_{fsc}}{B_f}\right) \tag{3.11}$$

Rearranging and dividing through by ρ_{fsc} & 5.615 we obtain;

$$\frac{\partial}{\partial x}\left(\frac{A_x K_x K_{rf}}{\mu_f B_f} \frac{\partial \Phi_f}{\partial x}\right)\Delta x + \frac{\partial}{\partial y}\left(\frac{A_y K_y K_{rf}}{\mu_f B_f} \frac{\partial \Phi_f}{\partial y}\right)\Delta y + \frac{\partial}{\partial z}\left(\frac{A_z K_z K_{rf}}{\mu_f B_f} \frac{\partial \Phi_f}{\partial z}\right)\Delta z +$$

$$q_{fsc} = \frac{V_b}{5.615} \frac{\partial}{\partial t}\left(\frac{\emptyset S_f}{B_f}\right) \tag{3.12}$$

The potential term is; $\frac{\partial \Phi}{\partial x} = \frac{\partial p}{\partial x} - \frac{1}{144} \frac{g}{g_c} \rho \frac{\partial G}{\partial x}$

Where; f = fluid phase (oil, water, or gas)

K_x = Absolute permeability in mD

K_{rf} = Relative permeability

μ = fluid viscosity in cp

B = formation volume factor, rb/STB

Φ = fluid potential

G = potential gradient

To obtain the flow equation for the slightly compressible fluid in our case we introduce the following assumptions;

- Weak functions of pressure are negligible
- The compressibility is a function of porosity
- Neglect the effect of fluid potential flow

$$\emptyset(C_\emptyset + C) \frac{\partial p}{\partial t} \quad \text{But } (C_\emptyset + C) = C_t \text{ and hence, } \emptyset C_t \frac{\partial p}{\partial t} \tag{3.13}$$

Using the above assumptions and substituting Eq. 3.13 into Eq. 3.12 we have;

$$\frac{\partial}{\partial x}\left(\frac{A_x K_x K_{rf}}{\mu_f B_f} \frac{\partial p}{\partial x}\right)\Delta x + \frac{\partial}{\partial y}\left(\frac{A_y K_y K_{rf}}{\mu_f B_f} \frac{\partial p}{\partial y}\right)\Delta y + \frac{\partial}{\partial z}\left(\frac{A_z K_z K_{rf}}{\mu_f B_f} \frac{\partial p}{\partial z}\right)\Delta z$$

$$+q_{sc} = \frac{V_b \emptyset C_t}{\alpha} \frac{\partial p}{\partial t} \tag{3.14}$$

We let α = 5.615, and Eq. 3.13 is the Multiphase flow equation for slightly compressible fluids.

For oil: $\frac{\partial}{\partial x}\left(\frac{A_x K_x K_{ro}}{\mu_o B_o} \ \frac{\partial p_o}{\partial x}\right)\Delta x + \frac{\partial}{\partial y}\left(\frac{A_y K_y K_{ro}}{\mu_o B_o} \ \frac{\partial p_o}{\partial y}\right)\Delta y + \frac{\partial}{\partial z}\left(\frac{A_z K_z K_{ro}}{\mu_o B_o} \ \frac{\partial p_o}{\partial z}\right)\Delta z + q_{osc} = \frac{V_b \emptyset C_t}{\alpha} \ \frac{\partial p}{\partial t}$

For water: $\frac{\partial}{\partial x}\left(\frac{A_x K_x K_{rw}}{\mu_w B_w} \ \frac{\partial p_w}{\partial x}\right)\Delta x + \frac{\partial}{\partial y}\left(\frac{A_y K_y K_{rw}}{\mu_w B_w} \ \frac{\partial p_w}{\partial y}\right)\Delta y +$

$$\frac{\partial}{\partial z}\left(\frac{A_z K_z K_{rw}}{\mu_w B_w} \ \frac{\partial p_w}{\partial z}\right)\Delta z + q_{wsc} = \frac{V_b \emptyset C_t}{\alpha} \ \frac{\partial p}{\partial t}$$

For gas: we must include the gas solubility in the oil phase (Rso in SCF/STB)

$$\frac{\partial}{\partial x}\left(\frac{A_x K_x K_{rg}}{\mu_g B_g} \ \frac{\partial p_g}{\partial x} + R_{so}\frac{A_x K_x K_{ro}}{\mu_o B_o} \ \frac{\partial p_o}{\partial x}\right)\Delta x + \frac{\partial}{\partial y}\left(\frac{A_y K_y K_{rg}}{\mu_g B_g} \ \frac{\partial p_g}{\partial y} + R_{so}\frac{A_y K_y K_{ro}}{\mu_o B_o} \ \frac{\partial p_o}{\partial y}\right)\Delta y$$
$$+ \frac{\partial}{\partial z}\left(\frac{A_z K_z K_{rg}}{\mu_g B_g} \ \frac{\partial p_g}{\partial z} + R_{so}\frac{A_z K_z K_{ro}}{\mu_o B_o} \ \frac{\partial p_o}{\partial z}\right)\Delta z + \left[q_{gsc} + R_{so} q_{osc}\right] = \frac{V_b \emptyset C_t}{\alpha} \ \frac{\partial p}{\partial t}$$

The Numerical Solution Method

Our mathematical model of the slightly compressible fluid is solved using a technique that is basically the finite-difference strategy for time-dependent formulations. In order to acquire the next time-step, the implicit approach is preferred is well acceptable than using the explicit one simulation approach in numerical method.

Condensed into time-dependent form from Eq. 3.14, the flow analog is as follows:

$$q = \frac{\partial^2 T}{\partial X^2} + \frac{\partial^2 T}{\partial Y^2} + \frac{\partial^2 T}{\partial Z^2} = \frac{1}{\alpha} \ \frac{\partial T}{\partial t} \qquad (3.15)$$

Applying implicit backward difference approximation whose derivative is elevated at time-level (n+1)

$$\frac{\partial P}{\partial t} \cong \ \frac{P(t^{n+1}) - P(t^n)}{\Delta t} = \frac{P^{n+1} - P_i^n}{\Delta t} \qquad (3.16)$$

$$T^n_{x_{i+1/2}}(P^{n+1}_{i+1} - P^{n+1}_i) - T^n_{x_{i-1/2}}(P^{n+1}_i - P^{n+1}_{i-1}) + q = \frac{V_b \emptyset C_t}{\alpha} \ P^{n+1}_i - P^n_i \qquad (3.17)$$

Finally, the finite difference scheme for the slightly compressible multiphase fluid flow ignoring fluid potential terms becomes;

$$\left[\left[\frac{A_x K_x K_{rf}}{\mu_f B_f \Delta x}\right]^n_{i+1/2,j,k} \left(P^{n+1}_{i+1,j,k} - P^{n+1}_{i,j,k}\right) - \frac{A_x K_x K_{rf}}{\mu_f B_f \Delta x}\right]^n_{i-1/2,j,k} \left(P^{n+1}_{i,j,k} - \right.$$
$$\left. P^{n+1}_{i-1,j,k}\right) \ldots . + q^{n+1}_{i,j,k} = \frac{V_b \emptyset C_t}{\alpha} \ \frac{P^{n+1}_{i,j,k} - P^n_{i,j,k}}{\Delta t} \qquad (3.18)$$

The general equation for solving a somewhat compressible fluid flow in terms of x is found in equation 3.18; the extension is the case in y and z. Phase f in a comparable case with Eq. 3.14 can be gas, water, or oil.

CHAPTER IV

Findings and Comments

This chapter will focus attention to the findings of this thesis, it is the most integral part of the research work. Relevant tables would be attached, containing the data used for the research as part of the data presentation. Under the findings, keen attention or priority would be given to the oil recovery factor, cumulative oil, average pressure POVO, oil production rate for all six scenarios. Lastly, the findings would be explained in clear terms under the result discussions through comparison and inference where necessary.

Data Presentation

Table 4.1. *Data table containing the array and petrophysical properties.*

Grid Property	Unit	Value
GRID dimension (I J K)	-	15 15 5
K-direction	-	Down
I-block width	ft	15*22
J-block width	ft	15*22
Thickness	ft	10
Grid top	ft	1500
PERM-I CON	mD	500
PERM-J CON	mD	500
PERM-K CON	mD	50
Porosity	%	30
Porosity ref. Pressure	Psi	14.7
Compressibility	Psi^{-1}	1E-6

Porosity ref. Temperature	°F	200
Reservoir Pressure	Psi	4000
Reservoir Temperature	°F	200

Table 4.1 above houses the array properties which forms the base data for the modeling purpose using CMG software. The porosity and permeability are both uniform (homogeneous). The first layer being the reference layer, is set at the sub-surface with a depth of 1500 ft, and each of the grid is allocated a thickness of 10 ft. Other data listed are the reservoir temperature and pressure whose values are 200 °F and 4000 Psia, respectively. Table 4.2 below will show the fluid density data that is used for the research work i.e., pure steam injection.

Table 4.2. *Fluid density data for the pure steam injection model*.

Component	Molecular Weight (lb/lbmole)	Mole Density (lbmole/ft3)	Mass Density (lb/ft3)	API %	Compressibility (l/psi)	Thermal expansion (l/F)	Critical Pressure (psi)	Critical Temperature (F)
Water	18.02	3.464	62.4	9.9	0.00	0.00	3280.2	705.18
Heavy Oil	378.93	0.1451	55	20.0	0.00	0.00	149.65	1107.8

Table 4.2 above shows a two-component system consisting of water and heavy oil, since we are dealing with a pure steam injection model. Next is to show a table consisting of the fluid surface condition. The fluid surface condition would be shown in Table 4.3 below i.e., values at atmospheric conditions before the occurrence of any activity in the reservoir.

Table 4.3. *Fluid surface condition data.*

Property	**Unit**	**Value**
Surface Pressure	Psi	14.70
Surface Temperature	°F	62.33
Surface Flash option	-	Phase seg. K (values)
Ideal Gas phase density	lbmole/ft^3	2.6243E-03
Liquid Density Unit	lbmole/ft^3	

The above stated data in Table 4.1 through 4.3 would be used to derive the thesis results and findings, and achieve its objectives. Substantive attention would be given to achieving the key results which are but not limited to; recovery factor, cumulative oil, oil production rate etc.

After completing and presenting all relevant data the next thing is to visualize important findings/ results of our research. Six models were used for the research, first being the no injection, then the normal first injection, and finally mimicking same model for four different injections. The first results would be presented for the no injection model, and the results to be first depicted under Figure 4.1 will show the 2D areal view of the reservoir model containing the production well without injection (no injection wells).

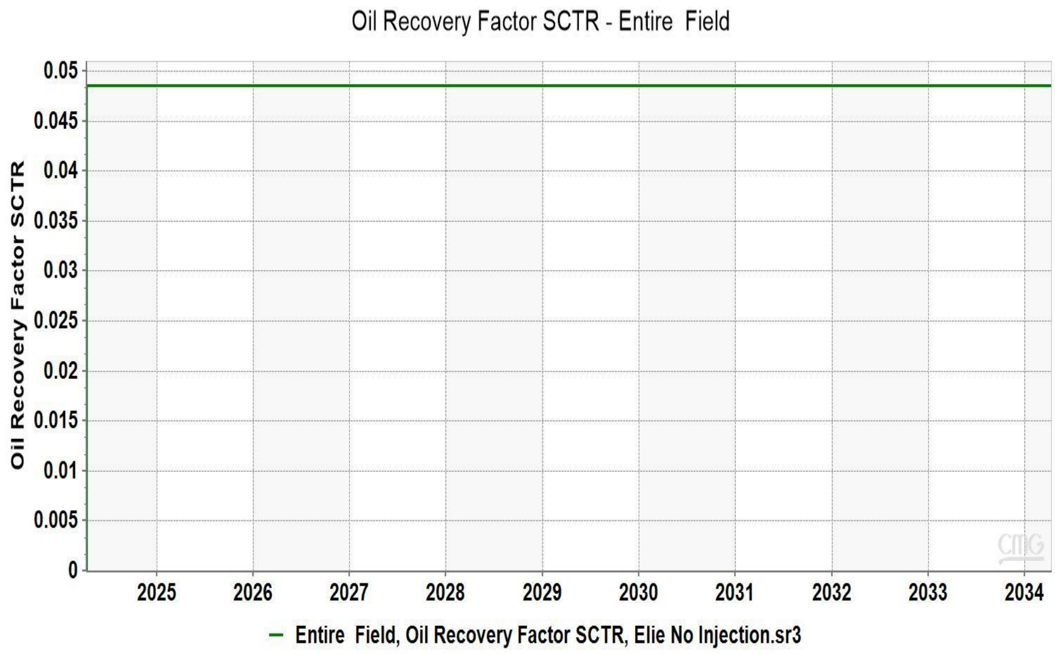

Figure 4.1. Oil recovery factor of the no injection model.

The above Figure shows the no injection model’s oil recovery factor as shown. The value obtained is negligible, this is because the EOR process is not initiated in the absence of injection. Figure 4.3 below will show the cumulative oil obtainable from the no injection model.

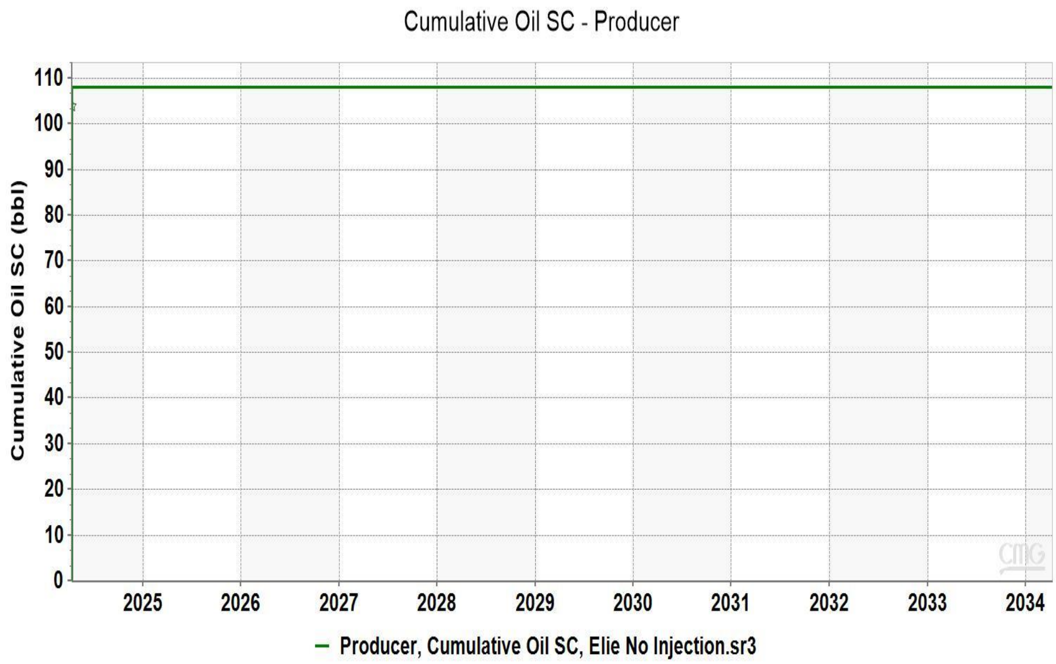

Figure 4.2. No injection model cumulative oil recovered.

The above Figure 4.3 is showing the cumulative oil with value of around 109 bbl. of oil per day, for the no injection EOR model.

The next section will contain the normal first injection model i.e. the first model with optimum stream attributes values (steam quality of 0.75, injection temperature 600 ^{0}F, and pressure of 6000 Psia). Figure 4.4 will show the average pressure versus time (POVO) for the first injection below.

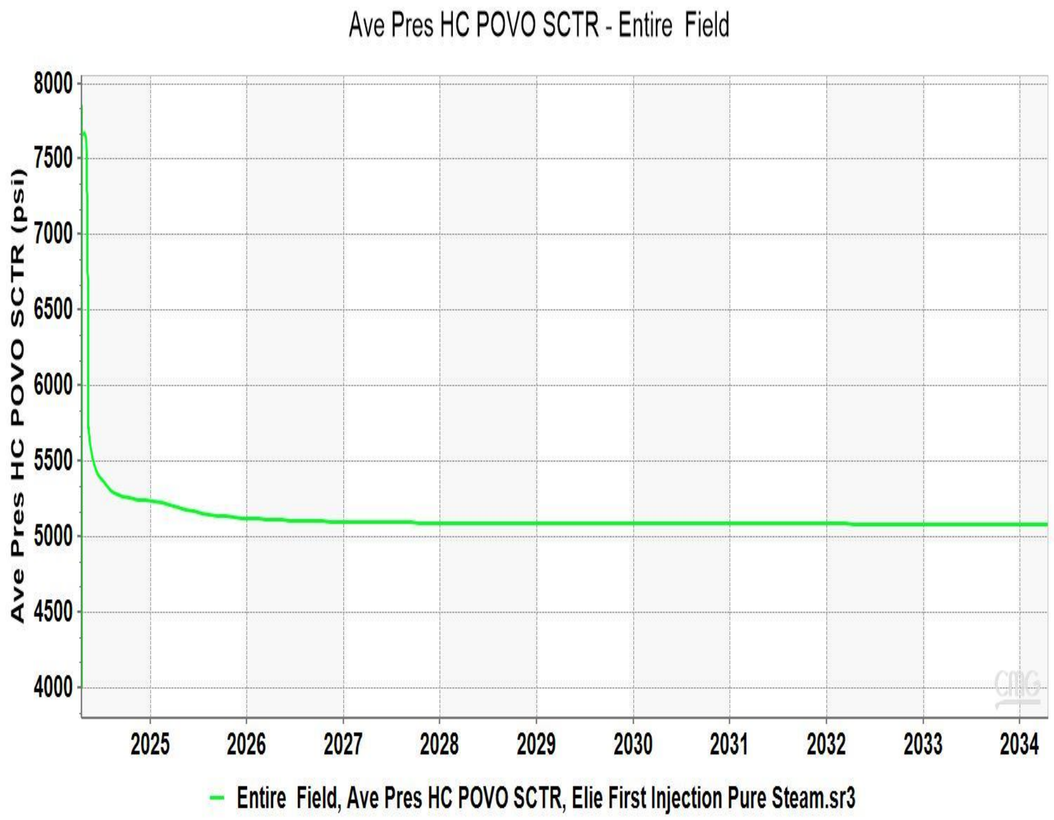

Figure 4.3. The average pressure HC versus time (POVO) for the first injection model.

Figure 4.4 above shows the average pressure versus time (POVO) for the first (normal) injection, the value started at a high of about 7650 psi and decline with time due to production to an overall value of 5050 psi. Figure 4.5 will show to us the first models' oil recovery factor below.

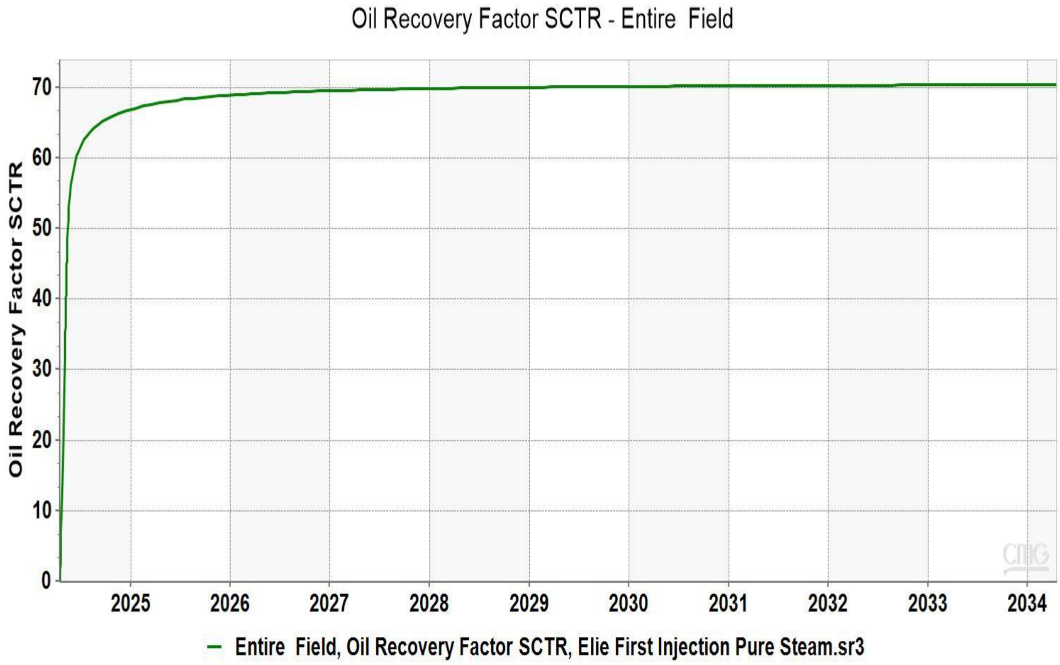

Figure 4.4. Oil recovery factor of the first injection model.

The above Figure 4.5 is showing an overall oil recovery factor of 70% over time, thanks to the optimum quality steam injected at an optimum temperature and pressure. In addition, Figure 4.6 will show the first injection model's cumulative oil below.

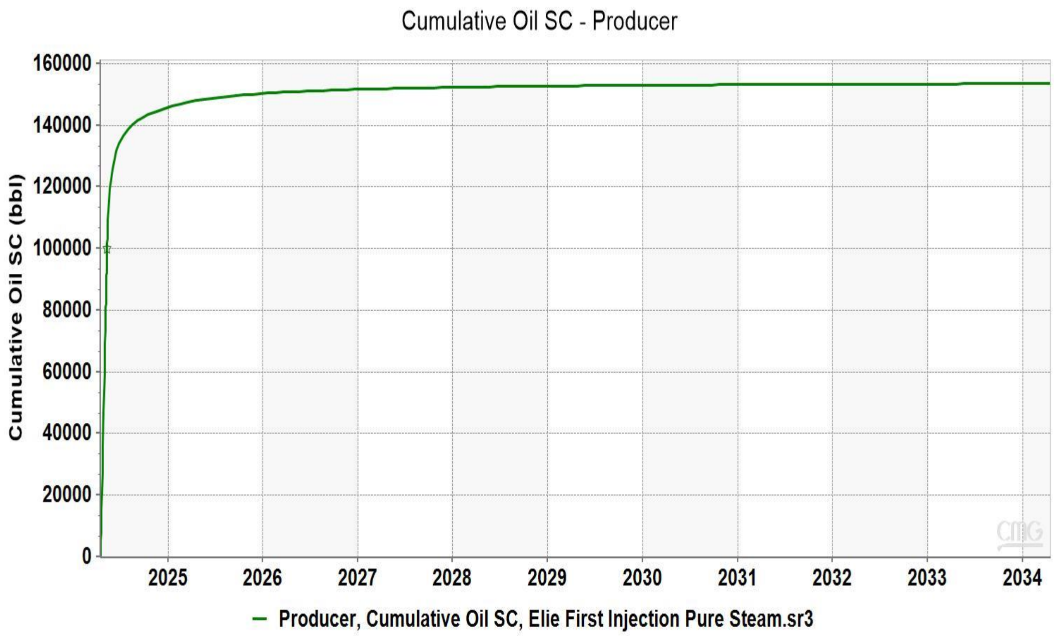

Figure 4.5. The first injection model's cumulative oil.

The model shows an appreciable value of cumulative oil of about 155000 bbls over 10 years.

The next section of the findings will contain images of all five scenarios from the different EOR models for generalizations. Figure 4.7. will show the comparative plot of recovery factor for all the five scenarios below.

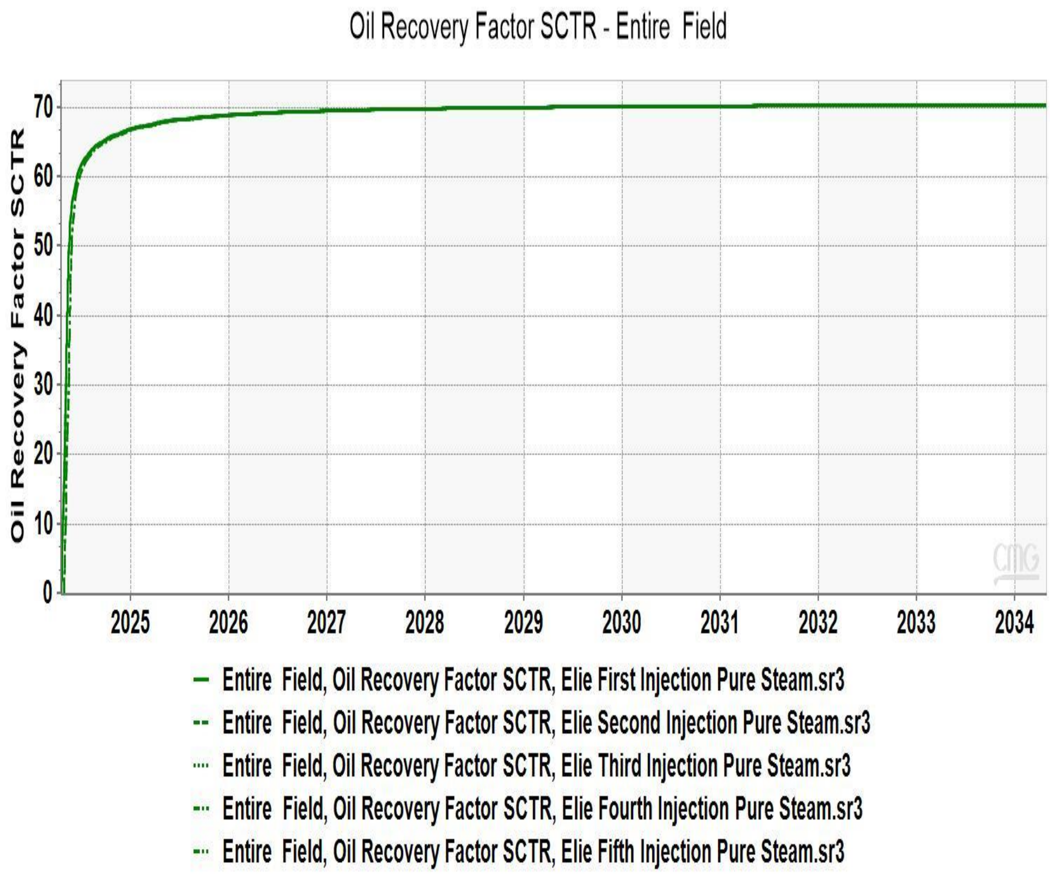

Figure 4.6. Showing a comparative plot of oil recovery factor for all five scenarios.

The Figure above shows a descriptive comparison of all five scenarios modelled for this research work. Detailed explanation would be given under result discussions section. Figure 4.8 below is also a comparative plot for all five scenarios but for cumulative oil.

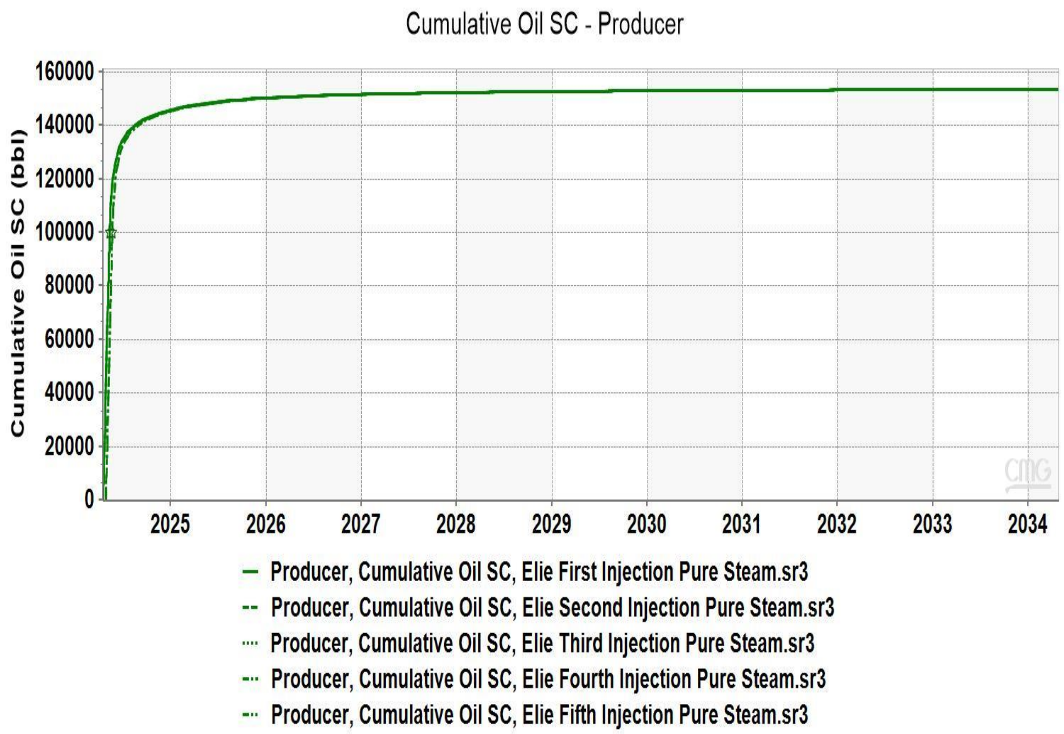

Figure 4.7. Comparative plot depicting cumulative oil for all five scenarios.

CHAPTER V
Discussion

This section would give detailed explanation of the results or findings from this experiment in paragraphs, with each paragraph addressing a key finding. The discussion would be divided into two parts, first as a consequence of the findings from this research. The second is a comparative with similar research deployed in the same field.

Enhanced oil recovery is deemed paramount when the natural energy of the hydrocarbon reservoir cannot sustain its' production. Thereby, the application of certain substances ranging from water, chemical, steam etc., becomes necessary to improve the flow characteristics of the reservoir fluid, from altering the viscosity to aiding mobility by working on key parameters like wettability, surface and interfacial tension. This research deploys the use of steam injection, in this case the steam injection will work to reduce the viscosity of the heavy oil, hence, improving its overall sweep efficiency towards the producer. In order to achieve EOR there is need to adequately maintain the reservoir at a bearable bottom-hole-flowing pressure. Our reservoir pressure being 4000 Psia, we decided to maintain our producer at a minimum bottom-hole pressure of 2000 Psia, and then to be able to inject at a very high bottom-hole pressure our maximum bottom-hole injecting pressure is set at 8000 Psia. Furthermore, our surface oil rate of the produce at 4000 bbl./day, and surface gas rate of injector to be able to inject steam at 2 million cubic feet per day (2000000 ft^3/day). The above values of bottom-home pressure, surface oil rate, and surface gas rate is used for all six models utilized in this research, with only difference in stream attributes.

The first result to be discussed is the average pressure versus time (POVO) for all the models. The average pressure versus time for the no injection model is zero since, there is no pressure decline due to draw-down. The first injection models' average pressure versus time started declining from an all-time high of 7650 Psia at the start of the production, to a lowest value of 5050 Psia and was maintained until the end of the simulation period, which is 10 years. The all-scenarios plot for average reservoir pressure versus time is essential the same for all the models as there is little difference in the value obtainable for all models.

In the aspect of oil recovery factor which is the most pivotal and important aspect of EOR performance testing. The no injection model shows a negligible value of recovery factor as expected due to no EOR process, on the contrary, the first injection model shows a very good recovery factor of 70%, thanks to the optimum steam injected. The injected steam for the first model possesses the following attributes; steam quality 0.75, injection temperature 600 ^{0}F, and an injection pressure of 6000 Psia. Consequently, the remaining models which involve four different injections aside the first one, with the first two involving an increase in steam attributes and the last two involving decrease to be able to make favorable comparison and result generalizations. The second injection has the following attributes; steam quality of 0.8, injection temperature 650 ^{0}F, injection pressure 6500 Psia. The third injection with attributes as; steam quality 0.85, injection temperature 700 ^{0}F, and injection pressure of 7000 Psia. The fourth injection and fifth involves decrease from the first (normal) injection. The fourth with steam quality 0.7, temperature of 550 ^{0}F and pressure of 5500 Psia, while the fifth with steam quality 0.65, temperature 500 ^{0}F and pressure 5000 Psia. All the scenarios gave a final oil recovery factor ranging between (70-71%), although there is slight difference at the inception of the simulation but yielded in almost same results for oil recovery. The findings of the recovery factor compared favorably to related research by Delazeri and Lamas (2021) using surfactant and Polymer injection in the same Pelican Lake field in Canada, the maximum oil recovery factor obtained is 16.58%.

The second part of our discussion focuses on research by Delamaide et al. (2014) in which he builds on the success recorded on Pelican Lake Field in 2000s where water flood is used to raise the recovery factor of the field from 5% to 10% of the original oil in place (OOIP). His research has shown the first successful deployment of polymer flooding in the heavy oil field of Pelican Lake which raises the recovery to 25% of OOIP in the mid-2000s. However, the findings from our research have shown an overwhelming oil recovery of (70-72%) of the OOIP, thanks to the viscosity reduction achieved by injecting steam. The attachment below will show a comparative plot of the three different techniques deployed to recover oil in the field, under Figure 4.9.

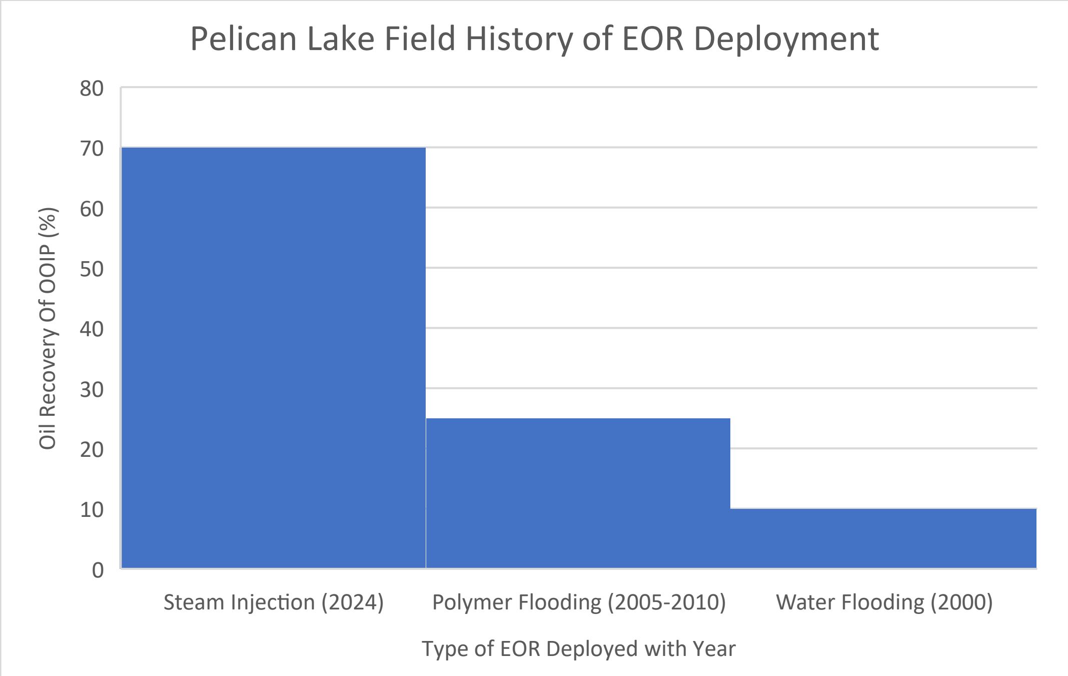

Figure 4.8. Comparative Plot of the different EOR deployed in Pelican Lake Field.

On a final note, results of this experiment have shown that when all steam attributes are either increased or decreased the resulting impact is negligible if the operating constraints are not altered especially when modeling with the CMG, so using an optimum steam attribute yielded a very good oil recovery and cumulative oil. Moreover, in relation to findings by Delamaide et al. (2014) it has been established that steam injection has proven more effective that water or polymer flood.

CHAPTER VI
Conclusion and Recommendations

This chapter which is the last of this thesis will provide us with a brief summary of what the research entails, in addition, it will give relevant conclusions based on the findings and related research. Lastly, recommendations for future research work will also be provided.

Study Summary

Enhance oil recovery has become one of the most sought of technology in the energy industry with high efficiency recorded from past deployment, to make for the high energy deficit globally. Research to account for this energy deficit led to researchers' investigating new techniques to solve this problem, it is a well-known fact that pressure decline during hydrocarbon production (oil and gas) due to draw down, and hence, finding a method capable of reenergizing the reservoir becomes eminent. These techniques range from does capable of mixing with the oil phase making the oil swell and reducing its viscosity, to injecting chemicals into the reservoir to enable in effecting mobility, and thermal techniques that aid in reducing oil viscosity. Steam based techniques have proven very effective in producing high oil recovery from heavy oil reservoirs, due to high viscosities from such reservoirs. Although, there are problems associated with steam-based techniques, like viscous fingering and gravity override, for this research the problem has been limited through the application of best quality steam, and avoiding prolonged injection. To achieve the research objectives, a no injection model was developed to test the model's efficiency, afterwards a First/ normal injection model is created with optimum steam attributes (steam quality, injection pressure, and temperature). In the first model, the results achieved were then compared with subsequent models to check the effect of varying stream attributes on oil recovery factor and cumulative oil recovery. As a consequence, the results yielded from the experiment were then compared with that from the literatures as it solves the thesis problem.

Conclusions

The emerging of EOR process in reservoir engineering and hydrocarbon production to solve the current global energy deficit, in this research the efficiency of pure steam injection was compared to that from literature. Six different models were made using CMG builder and deploying STARS simulator as a simulator of interest. Injecting steam into the reservoir used to increase its average pressure versus time. From the results obtained high average reservoir pressure versus time is maintained throughout the simulation period for the models involving steam injection around 5050 Psia as oppose to the 2000 Psia obtainable from the no injection model.

1. High oil recovery factor is obtainable from steam injection (70%) for heavy oil recovery. From the results obtained it has shown that, simultaneously increasing or decreasing all steam attributes (steam quality, injection pressure and temperature) does not affect oil recovery as can be seen from the results of this experiment. All the injection models yielded an overall recovery of around (70-71%).
2. Similarly, the cumulative oil recovered from all the injection models are yielding the same result. This is because the steam attributes are increased or decreased simultaneously. The cumulative oil recovery for the injection models is around 155000 bbls as opposed to the no injection model’s 109 bbls. Hence, this shows the necessity of using steam to recover heavy oil.

The above conclusions have suggested, the essence of using steam for heavy oil recovery as it functions effectively as can be seen from the overall oil recovery factor, and cumulative oil. On a final note, results of this thesis have shown the effectiveness of CMG software for modeling EOR projects.

Recommendations

Based on the conclusions derived from this research work and key findings achieved the bellow recommendations can be made.

1. Steam attributes should not be increased or decreased simultaneously in order to see the effect of steam injection. Kirmani et al. (2021) based his research on effect of injection rate on steam quality, hence, future research should focus attention on changing either steam quality, increasing injection pressure and decreasing temperature, in order to view its overall effect on oil recovery.

2. The model used for this research is only a mechanistic model without adequate reservoir data to mimic reality, as data is obtained essentially from literature survey as opposed to laboratory data.
3. Future attention should focus on the use of artificial intelligence in addition to software modeling for more accurate results.

The recommendations from this research if properly adhered to can yield better and more accurate results, in future research.

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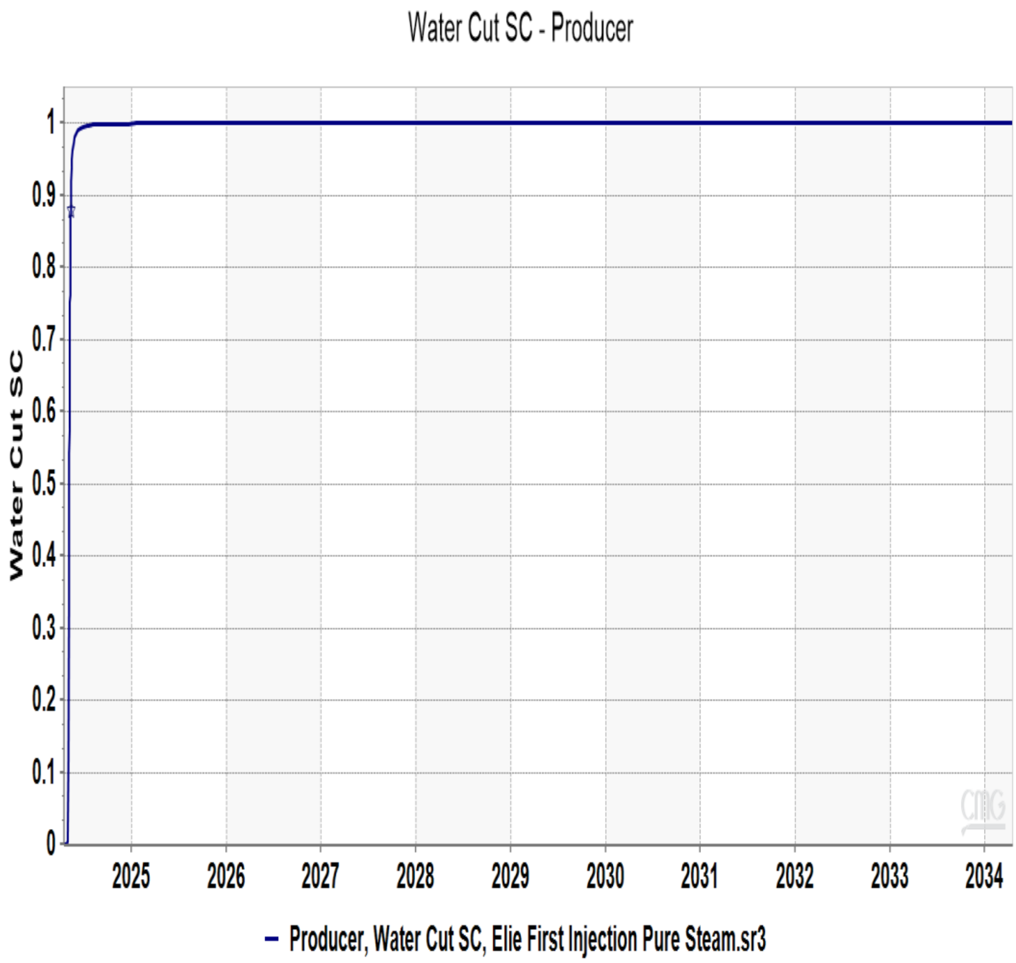
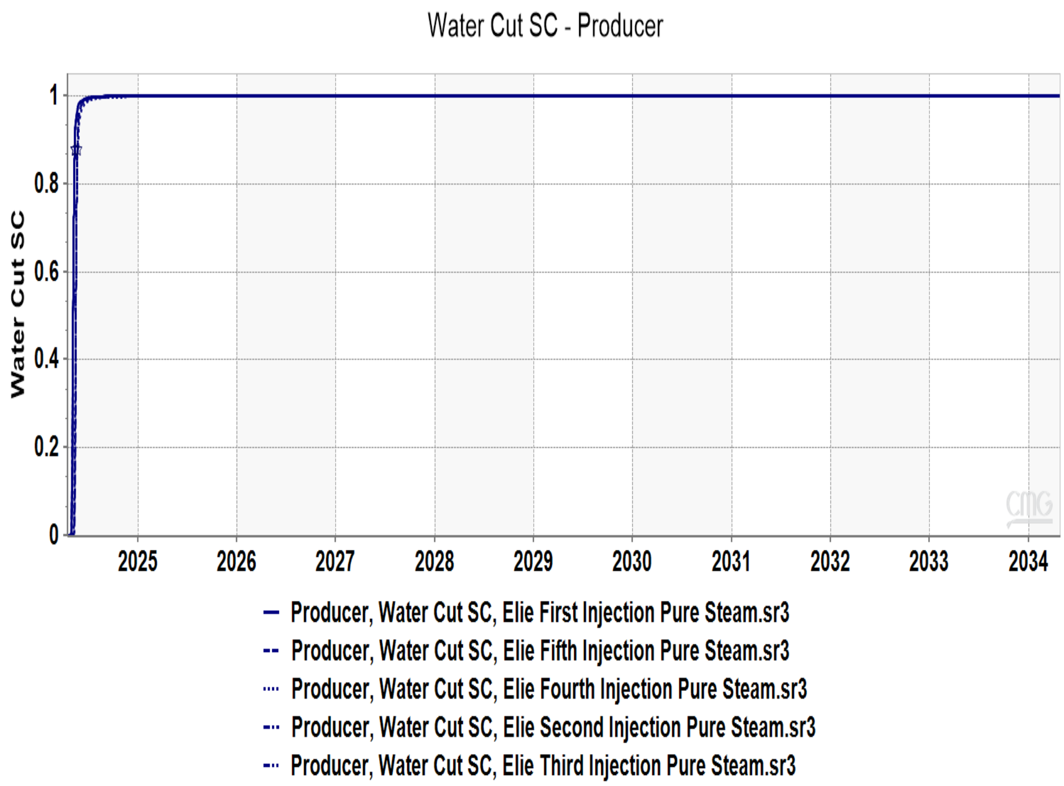
Appendices

Appendix A

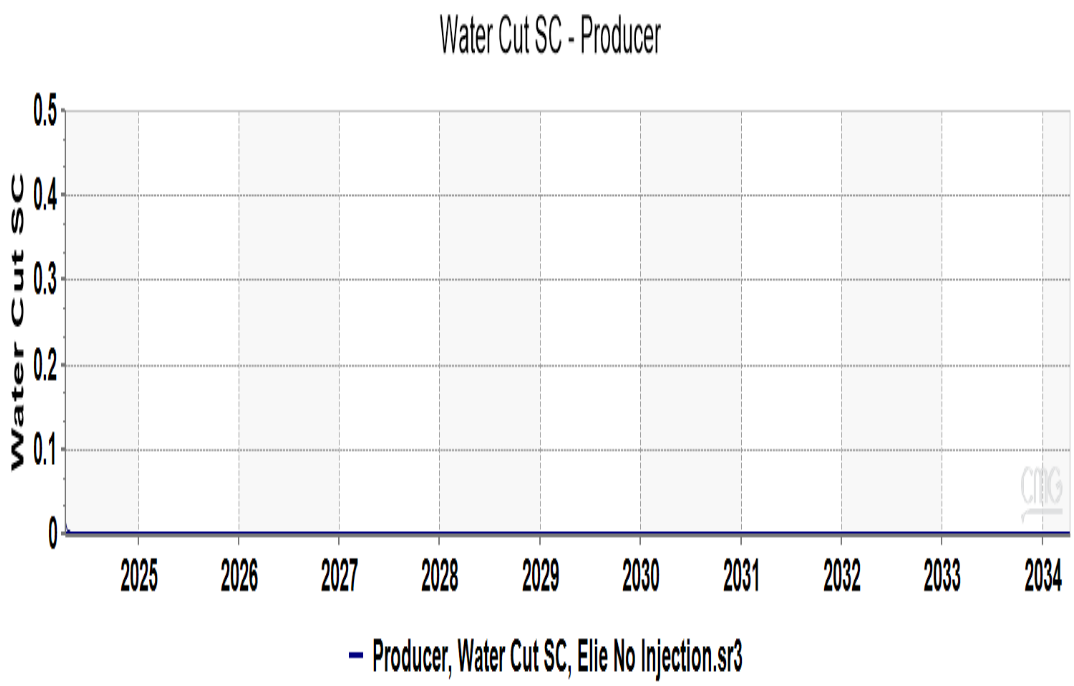
Plot of Water Cut for No Injection, First Injection, and All Scenarios



Plot of Water Cut for the First/ Normal Injection Model.



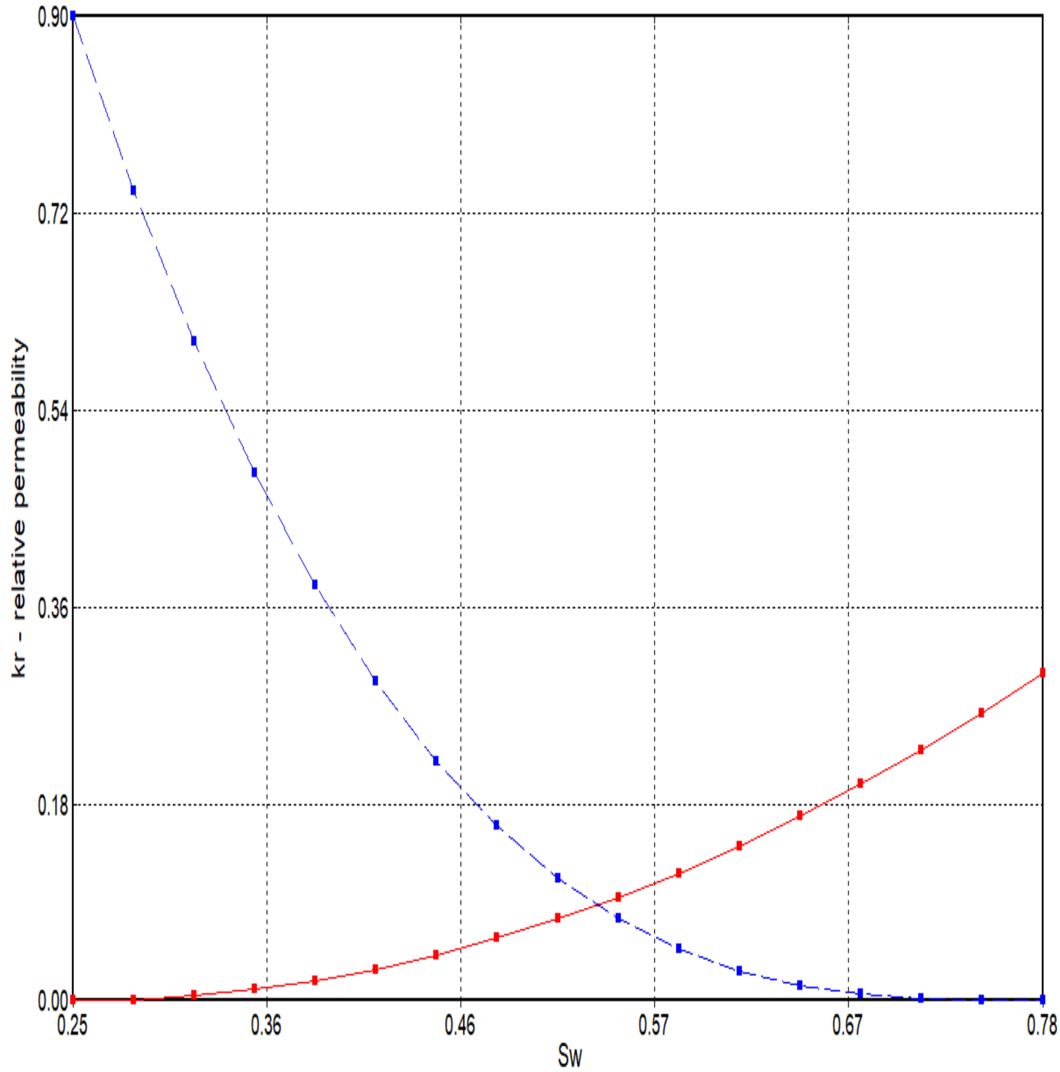
Plot of water cut for all Scenarios.



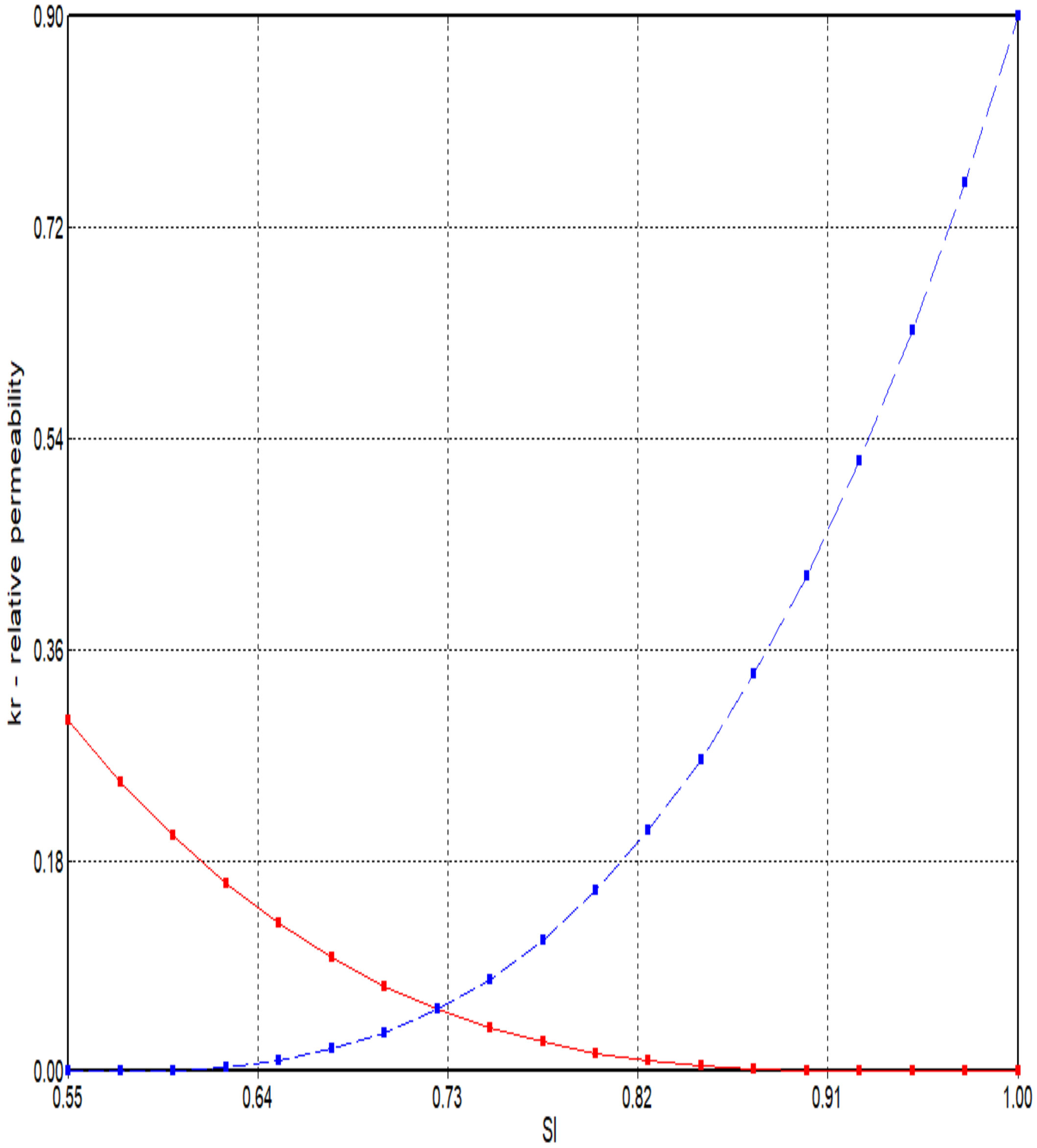
Plot of water Cut for No injection Model.

Appendix B

Relative Permeability Curves for Water and Oil



Water relative permeability curve.



Oil Relative Permeability Curve.

Appendix C

Some Sections of the Simulation Data File

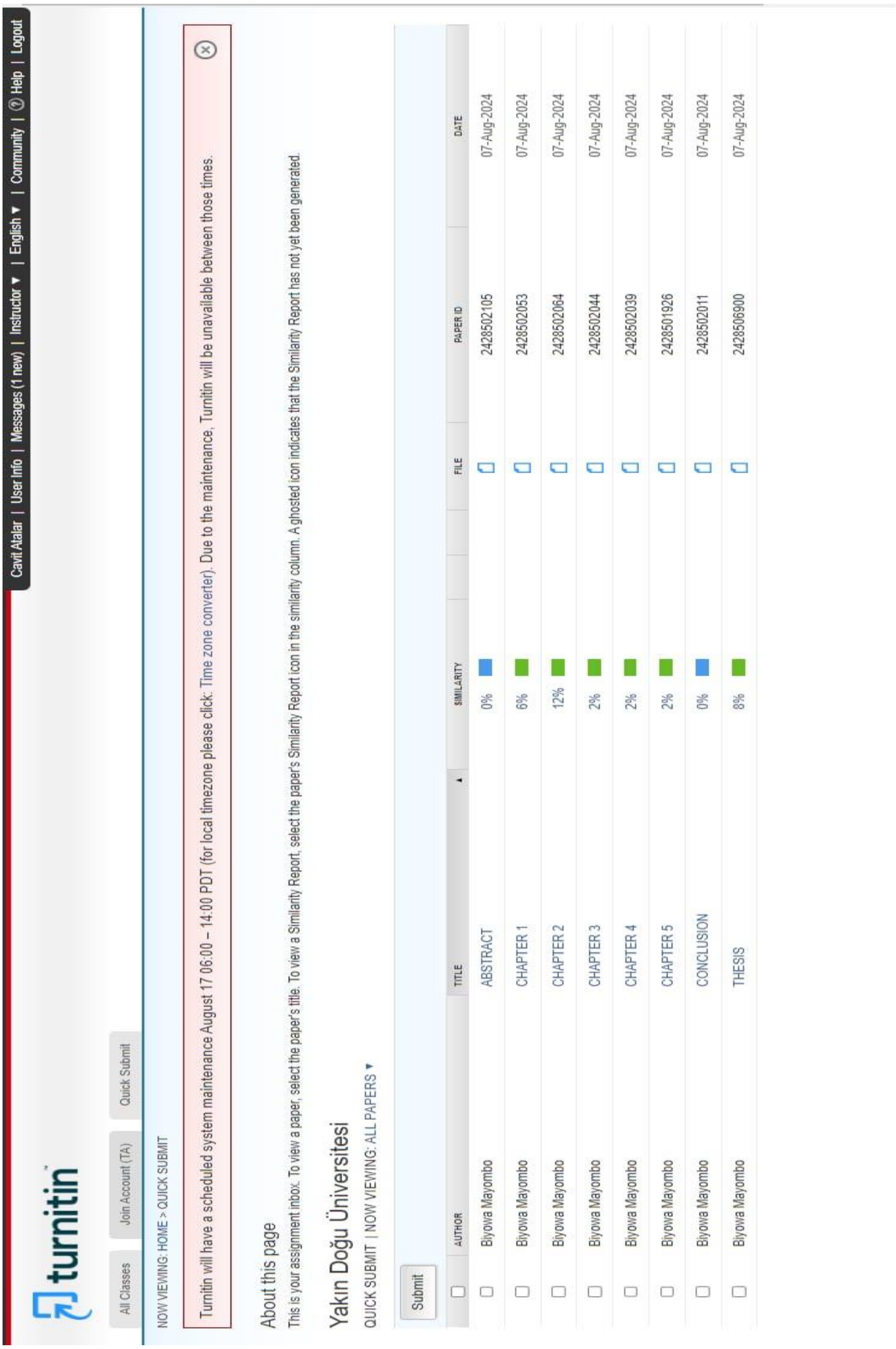
```
TITLE1 'First Injection'
 INUNIT FIELD
 TITLE2 'Pure Steam Model'
 CASEID 'CASE 2'
 WSRF WELL 1
 WSRF GRID TIME
 WSRF SECTOR TIME
 OUTSRF GRID PRES SG SO SW TEMP
 OUTSRF WELL LAYER NONE
 WPRN GRID 0
 OUTPRN GRID NONE
 OUTPRN RES NONE
 **
 ** Definition of fundamental cartesian grid
 **
 GRID VARI 15 15 5
 KDIR DOWN
 DI IVAR
  15*22
 DJ JVAR
  15*22
 DK ALL
  1125*10
 DTOP
  225*1500
 XOFFSET        0.0000
 YOFFSET        0.0000
 ROTATION       0.0000
 AXES-DIRECTIONS 1.0 -1.0 1.0
 ** 0 = null block, 1 = active block
 NULL CON        1
 PERMI CON       500
 POR CON      0.3
 PERMJ CON       500
 PERMK CON        50
 ** 0 = pinched block, 1 = active block
 PINCHOUTARRAY CON        1

 Loading Grid Module data into STARS arrays . . .
 Done


 END-GRID
 ** Model and number of components
 MODEL 2 2 2 1
 COMPNAME 'Water' 'Heavy Oil'
 CMM
```

```
18.015 378.93
PCRIT
3208.23 149.65
TCRIT
705.182 1107.81
MASSDEN
62.4 55
AVISC
0.5 1
BVISC
0 0
PRSR 14.7
TEMR 200
PSURF 14.7
ROCKFLUID
RPT 1 WATWET

INITIAL
VERTICAL OFF

INITREGION 1
PRES CON        4000
TEMP CON         200
NUMERICAL

CONVERGE TOTRES TIGHT
TFORM ZT
ISOTHERMAL
NORTH 150
ITERMAX 150
```

#	Item	Units	Value
1	Gross formati...	ft3	5.4450E+06
2	Formation por...	ft3	1.6335E+06
3	Aqueous pha...	ft3	4.0837E+05
4	Oil phase volu...	ft3	1.2251E+06
5	Gaseous pha...	ft3	0.0000E+00

Appendix D

Turnitin Similarity Report



AUTHOR	TITLE	SIMILARITY	FILE	PAPER ID	DATE
Biyowa Mayombo	ABSTRACT	0%		2428502105	07-Aug-2024
Biyowa Mayombo	CHAPTER 1	6%		2428502053	07-Aug-2024
Biyowa Mayombo	CHAPTER 2	12%		2428502064	07-Aug-2024
Biyowa Mayombo	CHAPTER 3	2%		2428502044	07-Aug-2024
Biyowa Mayombo	CHAPTER 4	2%		2428502039	07-Aug-2024
Biyowa Mayombo	CHAPTER 5	2%		2428501926	07-Aug-2024
Biyowa Mayombo	CONCLUSION	0%		2428502011	07-Aug-2024
Biyowa Mayombo	THESIS	8%		2428506900	07-Aug-2024

Appendix E

Ethical Approval Letter

YAKIN DOĞU ÜNİVERSİTESİ

ETHICAL APPROVAL DOCUMENT

Date: …../06/2024

To the **Institute of Graduate Studies**

The research project titled **“SIMULATION OF STEAM INJECTION FOR ENHANCING OIL RECOVERY IN PELICAN LAKE FIELD, CANADA’’** 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