COMPARISON OF CO2 GAS INJECTION AND WATER ALTERNATING GAS INJECTION ON AN OIL RESERVOIR USING COMPUTER MODELLING GROUP STEAM THERMAL ADVANCED RECOVERY SYSTEM

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BENIN CITY.

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CERTIFICATION

This is to certify that this project was carried out by OGUNYEMI COMFORT MAYOWA of the Department of Petroleum Engineering with matriculation number ENG1805567 in partial fulfilment of the requirements for the Award of the Degree, Bachelor of Engineering(B.ENG).

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DEDICATION

This thesis is dedicated to GOD Almighty who made it possible to successfully complete the study. The work is also dedicated to my Father, Mother, Siblings and Friends who have taught me that the best kind of knowledge to have is that which is learned for its own sake and even the largest task can be accomplished if it is done one step at a time.

ACKNOWLEDGEMENT

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Finally, I will forever be thankful to University of Benin for the opportunity and exposure given to me during my industrial training process.

ABSTRACT

Enhanced oil recovery play a crucial role in maximizing hydrocarbon production from mature oil reservoirs. This study investigates the comparative performance of CO2 injection and water alternating gas (WAG) injection on an oil reservoir using CMG STARS reservoir simulation software. The study aims to assess the effectiveness of these two EOR methods in enhancing oil recovery and to identify the key factors influencing their performance. Preliminary findings suggest tha WAG injection demonstrates superior performance in enhancing oil recovery compared to CO2 injection. The alternating injections of water and gas improve sweep efficiency and promote better displacement of oil within the reservoir. Factors such as reservoir heterogeneity, fluid properties, injection rates and timing significantly influence the effectiveness of both EOR methods.

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CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND TO THE STUDY

With oil consumption scaling over the average of 99.57 million barrels per day (b/d), oil and gas, typically known as fossil fuels, saw a rapid rise among alternative energy sources, such as nuclear, biomass, and renewable energy. This was the case in several countries. Maximizing oil recovery from previously exploited well resources is necessary for fulfilling the world's growing energy demand due to a shortage of energy supplies and rising global temperatures. There are three types of oil recovery: primary, secondary, and tertiary. Primary recovery has to do with using the reservoir's internal pressure and properties to extract oil. Pressure from outside the reservoir can be used to recover oil after the initial reservoir pressure has been lost. Injecting materials with identical characteristics to the reservoir fluid is the method utilized in secondary recovery. Primary recovery processes only cover 5– 10% original oil in place, this oil rate production is plummeted regarding depletion of fluids on the rock matrixes and pressure drop by passing the production time. (Al Shehhi et al., 2015; Campbell, 2002; Djuraev et al., 2017; Hascakir, 2017). The combined recovery efficiency of primary and secondary oil recovery is about 33% of the oil that was initially in situ (OOIP). In order to increase the extraction of hydrocarbons from reservoirs that the primary and secondary methods are unable to fully recover, the oil and gas industry uses tertiary oil recovery which is a collection of cutting-edge techniques and technology. EOR fully known as Enhanced oil recovery is a part of tertiary recovery and is the process of injecting different materials into a reservoir or oil well that has seen reduction in production to change the chemical and physical characteristics of the oil, hence simplifying its extraction.

The tertiary recovery method has a successful recovery factor of about 75%, according to the US Department of Energy. Two main benefits of the EOR are increasing the mobility of the oil and also helps get a higher yield. One type of EOR is called CO2-mediated EOR (CO2-EOR), in which CO2 is injected into an oil field that is running low in order to decrease the crude's viscosity and adhesion qualities. This lowers the amount of energy needed to transport the crude toward a producing well. There are about 160 active CO2 EOR projects worldwide, according to the Global CCS Institute, and CO2-EOR initiatives in the oil industry have expanded. The first application of CO2-EOR dates back to 1972, where it was employed commercially in the Sacroc field. For over two decades, CO2 EOR has been demonstrated to be both economically and technically viable. EOR with CO2 injection also aids in lowering CO2 emissions, which are a factor in climate change as well as global warming. Since it can increase the amount of crude oil produced from mined oil fields, enhanced oil recovery, or EOR, has attracted a lot of attention globally during the past few decades. Because of its high oil recovery rate and recyclability, carbon dioxide (CO2) flooding is one of the most effective enhanced oil recovery procedures.

A type of enhanced oil recovery is Water-alternating-gas flooding. Water-alternating gas flooding deals with the injection of water so as to improve the sweep efficiency and mobilize oil that would have being left behind after waterflooding or gas injection alone. The concept of Water-alternating- gas injection dates back to the early 1960s. It was first used in North Burbank Unit, Oklahoma. WAG increases the total recovery of an oil reservoir to about 70%.

1.2 PROBLEM STATEMENT

Low reservoir pressure and large amounts of residual oil in dead oil reservoirs provide a major problem to the oil and gas sector. Large amounts of trapped oil are frequently left behind by conventional primary and secondary recovery procedures, making the use of enhanced oil recovery (EOR) techniques necessary to increase production efficiency. In order to maximize oil recovery from a depleted reservoir, this study compares two well-known EOR techniques: continuous CO2 injection (CO2 flood) and Water Alternating Gas (WAG) injection with CO2.

1.3 AIM

The aim of this study is to use the commercial reservoir simulator CMG STARS to perform a comparative analysis of CO2 gas injection and Water Alternating Gas (WAG) injection with CO2 for Enhanced Oil Recovery (EOR) in a deadoil reservoir. The beneficial effects of each approach will be assessed in this analysis with respect to economic viability, operational simplicity, sweep efficiency, and oil recovery techniques. Finding the best EOR method for a given reservoir's features is the ultimate objective since it maximizes oil recovery and financial return while reducing environmental effect.

1.4 OBJECTIVES OF THE STUDY

1. Model CO2 injection in the deadoil reservoir using CMG STARS to quantify oil recovery due to mechanisms like swelling and miscibility.

2. Model WAG injection with CO2 in CMG STARS to evaluate its effectiveness in improving sweep efficiency compared to CO2 flood.
3. Analyze the simulation results to compare the ultimate oil recovery achieved by CO2 flood and WAG injection.
4. Identify key operational challenges associated with implementing both CO2 flood and WAG injection.
5. Conduct a simplified economic analysis comparing the costs and potential benefits of each EOR method.
6. Based on the simulation results and economic analysis, recommend the most suitable EOR method (CO2 flood, WAG, or potentially a combination) for the specific reservoir.

1.5 SCOPE OF STUDY

This project aims to conduct a comparative analysis of Carbon Dioxide (CO2) gas injection and Water Alternating Gas (WAG) injection with CO2 for Enhanced Oil Recovery (EOR) in a depleted reservoir. CMG STARS, a commercial reservoir simulator, will be utilized to model and evaluate the effectiveness of each method.

The study will focus on the following key aspects:

- **Reservoir Characterization:** A representative geological model of the deadoil reservoir will be established, incorporating essential properties like porosity, permeability, and heterogeneity. Fluid properties of the reservoir oil and brine will be characterized using relevant methods.

- **CMG STARS Simulations:** Separate CMG STARS models will be built for CO2 flood and WAG injection scenarios. The simulations will encompass a defined injection period with realistic injection rates and well placement. Sensitivity analyses will be conducted to assess the influence of critical parameters like injection pressure and water-to-CO2 injection ratio on recovery.
- **Evaluation and Analysis:** The primary comparison metric will be the ultimate oil recovery factor obtained from each simulation run. Sweep efficiency achieved by each method will also be evaluated. Operational challenges associated with each EOR technique will be identified, and a simplified economic analysis will be performed to compare their cost-effectiveness.

A limitation is the fact that the study will be confined to a single representative reservoir model. Geochemical interactions and long-term economic viability will be conceptually addressed but not extensively modeled.

1.6 SIGNIFICANCE OF STUDY

The comparative analysis of CO2 injection and Water Alternating Gas (WAG) injection for Enhanced Oil Recovery (EOR) in a deadoil reservoir using CMG STARS holds significant value for the oil and gas industry. Here's how this study contributes:

1. Improve oil recovery from depleted reservoirs using CO2 injection and WAG injection techniques.
2. Enhance understanding of CO2-based EOR methods (CO2 flood and WAG injection) through CMG STARS simulations.

3. Compare sweep efficiency, operational challenges, and economic feasibility of CO_2 flood vs. WAG injection.
4. Guide selection of the most suitable EOR strategy for a specific reservoir.
5. Showcase the application of CMG STARS as a valuable tool for EOR analysis.
6. Acknowledge the importance of sustainable practices in EOR, such as CO_2 capture and storage.

CHAPTER TWO

LITERATURE REVIEW

2.1 OIL RECOVERY

Oil recovery also known oilfield recovery is the process of extracting crude oil from underground reservoirs. Oil recovery is an important sector of the oil and gas industry. Extracting oil from the reservoir is not as easy as drilling underground, sticking pipes in and then producing hydrocarbons; Different techniques are needed depending on the geology, pressure, and viscosity of the oil. There are three main types of oil recovery; these are Primary recovery, Secondary recovery and Tertiary recovery which is also known as enhanced oil recovery.

2.2 TYPES OF OIL RECOVERY

2.2.1 PRIMARY RECOVERY

Primary recovery is the initial stage of oil recovery from the underground reservoirs to the surface. It is the easiest and cheapest means of oil recovery among the three types of oil recovery because it relies on the natural pressure within the reservoir to push oil towards the production wells. It is like the easy oil that flows out on its own, like squeezing a ripe orange. It is a phase of oil recovery that typically occurs after the drilling of a well and the initial discovery of the reservoir. The pressure that helps with primary recovery is usually a result of the initial conditions in the reservoir, such as the gas cap and water drive. The gas cap contains natural gas, and the water drive involves the movement of water through the reservoir. The mobility of oil, water, and gas within the reservoir rock determines how easily these fluids can flow towards the production well. The mobility ratio, which compares the mobility of injected fluids (like water or gas) to that of the oil, plays a crucial role in the effectiveness of primary recovery.

The methods or production techniques normally used in primary recovery are either production using the normal reservoir pressure, use of gas lifts to lighten the oil column and improve its flow to the surface or the use of rod pumps to lift oil from the wellbore when natural pressure is insufficient. The efficiency of primary recovery is between 10-40% of the oil originally in the reservoir[Knapp and Lechthaler], but then as pressure in the reservoir decreases the rate at which the oil in the reservoir flows out also decreases significantly. This phenomenom makes primary recovery a method that isn't effective for all types of reservoirs, particularly those with low permeability or viscous oil.

There are different types of primary recovery mechanisms. The main types of primary recovery mechanisms are Natural water drive, Natural Gas drive, Gravity drainage, Rock and fluid expansion drive, Solution gas drive, Gas cap drive and Combination drive (Fatemi and Sohrabi, 2013; Holt et al., 2009; Ju et al., 2017; Monger et al., 1991; Nasralla and Nasr-El-Din, 2014). Natural water drive is the mechanism that has water naturally present in the reservoir and the water acts as the driving force to push oil towards the production wells. As oil is extracted, water moves into the voids left behind, exerting pressure on the remaining oil and assisting in its recovery. Natural Gas drive is a drive mechanism that occurs in reservoirs containing a significant amount of natural gas. The natural gas expansion acts as the driving force. As oil is produced, the natural gas expands and migrates into the space vacated by the extracted oil, exerting pressure and helping to push more oil towards the production wells.

Gravity Drainage is a drive mechanism that occurs when the oil naturally flows downward due to gravity towards the production wells. This mechanism is most effective in reservoirs where oil is lighter than water and where there is a significant difference in density between the oil and surrounding fluids. Rock and fluid expansion is a mechanism relies on the expansion of reservoir rock and fluids due to the reduction in pressure as oil is produced. As oil is extracted, the reservoir rock and fluids expand, creating additional space for oil to flow towards the production wells. Solution Gas drive exists in reservoirs where oil contains dissolved gas. Solution gas is a key drive which deals with the natural expansion of the dissolved gas in the oil upon reduction of pressure at the wellbore[Morris Muskat]. This mechanism is particularly effective in reservoirs with high-pressure gradients. For Gas cap drive, Reservoirs with a natural gas cap above the oil zone utilize the pressure exerted by the gas to drive oil towards the production wells. As oil is produced, the gas expands and migrates downward, pushing more oil towards the surface.

Lastly, we have the Combination drive which is the operating simultaneously or sequentially multiple primary recovery mechanisms within a reservoir depending on its geological characteristics and fluid properties.

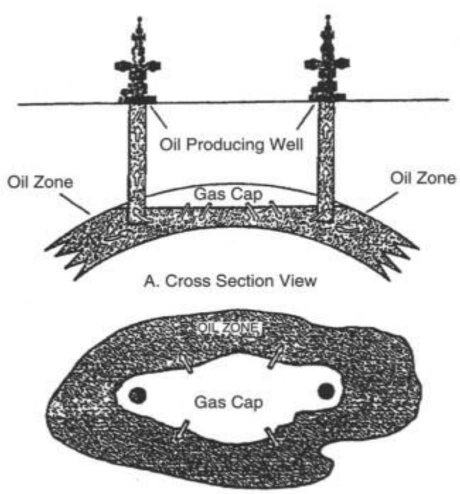


Fig 2- 0-1 Gas Cap primary recovery

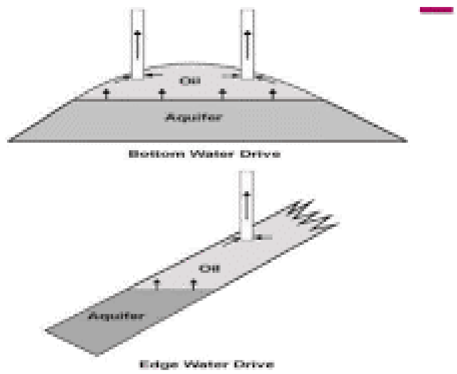


Fig 2- 0-2 Water drive primary recovery

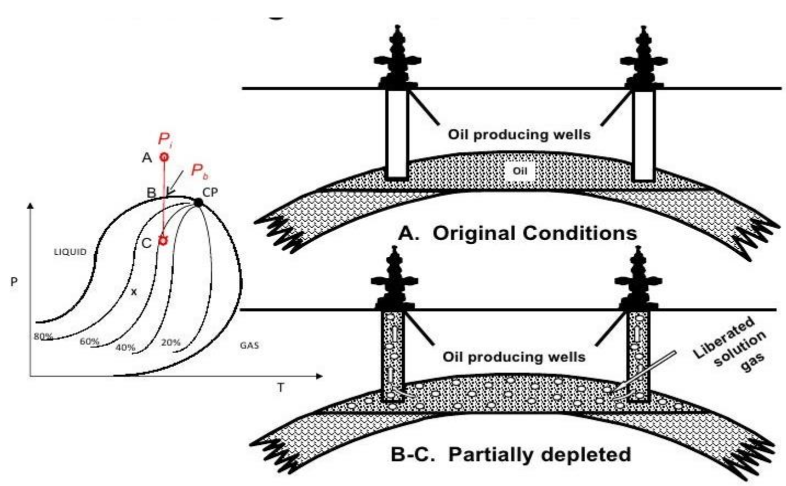


Fig 2- 0-3 Solution gas drive recovery

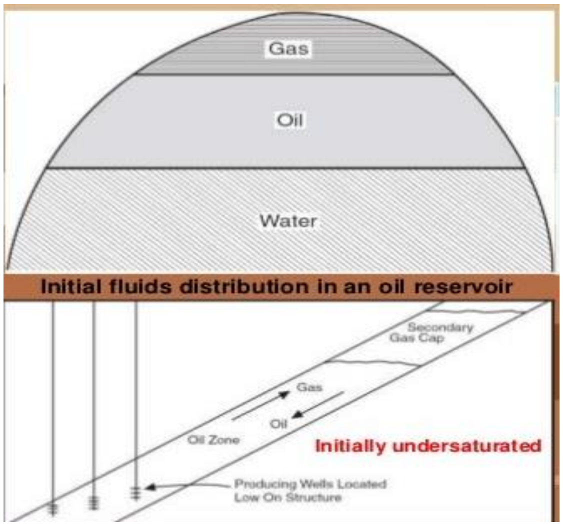


Fig 2- 0-4 Combination drive

2.2.2 SECONDARY RECOVERY

Secondary recovery takes off where primary recovery ends, It's methods are used to recover additional oil after a significant amount of the original oil in place (OOIP) has been produced by primary recovery mechanisms[Knapp and Lechthaler]. It is like giving the reservoir a gentle push to coax out additional oil that wouldn't flow freely anymore. Secondary recovery makes use of materials that have the same properties as the fluids in the reservoir. The primary goal of secondary recovery is to enhance oil production and increase the recovery factor by injecting fluids into the reservoir to displace and push more oil towards the production wells either by injecting water or gas.

The common techniques used in secondary recovery are waterflooding, gas injection, immiscible gas flooding and miscible gas flooding. Waterflooding is the most widely used method, injecting water into the reservoir to maintain pressure and displace oil[Henry J.

Stegemeier]. Gas injection which involved drilling additional wells aside production wells known as injection wells to inject gases like natural gas, nitrogen or CO_2 to either push the oil, reduce viscosity, or dissolve in oil to improve flow. Immiscible gas flooding is similar to gas injection but uses gases that don't mix with oil (like nitrogen) to create channels for oil flow. Miscible gas Uses gases like CO_2 that dissolve in oil, reducing its viscosity and mobilizing it for easier production. Waterflooding is often the most cost-effective, but gas injection can be more efficient for heavier oils or tight reservoirs.

Secondary recovery is good and effective with a recovery factor of additional 20-40% but not as effective or impactful as tertiary recovery. Issues regarding water sourcing and disposal is faced as a result of large volumes of water being required. Another challenge that might be encountered is the emission of greenhouse gases due to poor management. Also, Secondary recovery projects require careful planning, design, and implementation to ensure effectiveness and minimize environmental impact.

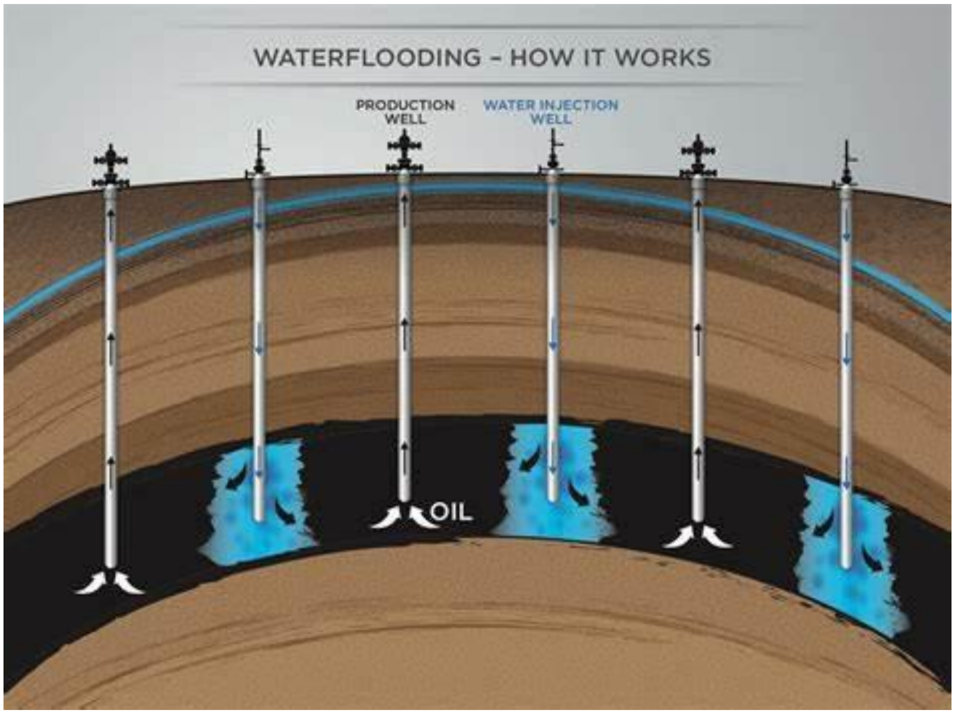


Fig 2- 0-5 Water flooding secondary recovery

2.2.3 TERTIARY RECOVERY

Although secondary recovery methods can recover a significant amount of oil, a substantial portion of the OOIP (Original Oil In Place) remains trapped in the reservoir[Knapp and Lechthaler]. Tertiary recovery otherwise known as enhanced recovery is the third method employed to extract the residual oil after both primary and secondary methods have being used. There are different methods under enhanced oil recovery. The main ones are Thermal recovery, gas recovery and chemical recovery. Others are microbial recovery method, Acoustic recovery method and electromagnetic recovery method.

2.2.3.1 THERMAL FLOODING

Thermal recovery involves injecting hot steam or water into the reservoir to reduce oil viscosity and improve its flowability. Examples include steamflooding, in-situ combustion and cyclic steam injection. Steamflooding deals with injecting high pressure steam into the reservoir, heating the oil and surrounding rock formations. Steamflooding is a mature and robust technology for recovering heavy oil[Ofil and MacDonald]. Steamflooding offers high recovery rates but is also the most energy-intensive and expensive. Cyclic steam injection is the injection of steam into a well, soaked for a period, and then produced to recover heated oil before repeating the cycle. Steam stimulation (huff and puff) has been a successful and economic method for improving well productivity in heavy oil reservoirs[Vazquez and Norman]. It is less energy-intensive than continuous steam flooding but has lower recovery rates.

For in-situ combustion, Thermal flooding is particularly effective for extracting viscous heavy oils that are normally difficult or impossible to produce with primary or secondary methods. In-situ combustion involves injecting oxygen usually air into the reservoir, igniting the oil and using the heat generated to reduce oil viscosity thereby making it easier to flow and then also creating steam which further thins the oil and helps drive it towards production wells. There are two primary types of in situ combustion: forward combustion and reverse combustion. Forward combustion involves igniting the oil in front of the injection well and moving towards the production well, while reverse combustion ignites the oil in front of the production well and moves towards the injection well.

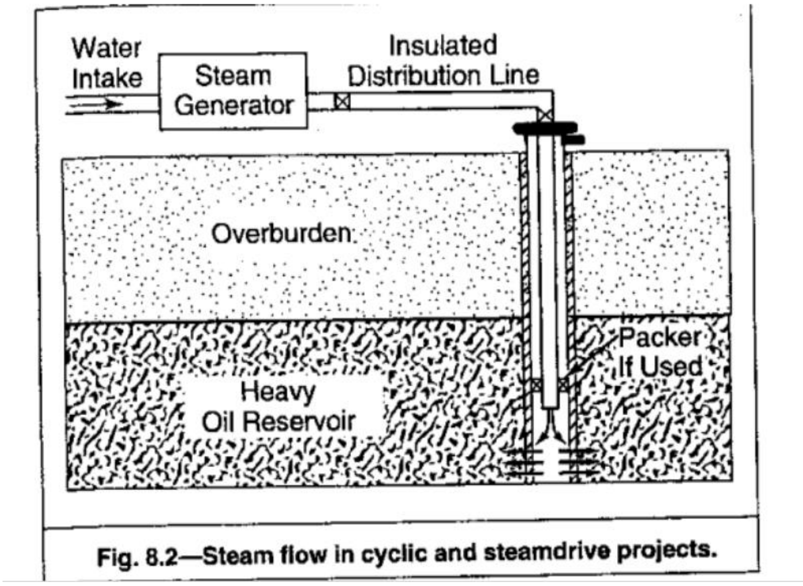


Fig 2- 0-6 Cyclic steam injection Thermal recovery

2.2.3.2 GAS RECOVERY

Gas recovery also known as gas injection or gas flooding is a tertiary recovery method that involves injecting gases, such as natural gas, nitrogen, or carbon dioxide (CO2), into an oil reservoir to displace and push additional oil towards production wells, thus increasing the ultimate recovery factor of the reservoir. The gases injected works in two ways; displacement whereby the injected gas pushes the oil towards production wells, similar to waterflooding in secondary recovery and miscibility whereby some gases, like CO2, can mix with the oil, reducing its viscosity and making it flow more easily. There are three types of gas injection, these are ; Immiscible gas injection, miscible gas injection and water alternating gas injection. Immiscible gas injection is the type of gas injection that primarily uses nitrogen or natural gas for displacement. This is suitable for lighter oils and offers high injectivity but limited oil swelling. Miscible gas injection is the type of gas injection that involves using CO2 for both displacement and oil swelling. Miscible gas flooding offers the advantage of high oil recovery, approaching 100% of the contacted oil, for certain crudes[M.A Lake\ et. al]. This works well for heavier oils but requires higher injection pressures and careful management. Water alternating gas injection deals with injecting water and gas alternately, leveraging the benefits of both methods. This optimizes reservoir sweep efficiency and oil recovery but is more complex to operate.

Gas injection is beneficial because it recovers more oil than traditional methods, potentially increasing ultimate recovery by 20-50%. Also, CO2-based miscible gas injection offers potential for carbon capture and storage (CCS). Gas tertiary recovery is most effective in reservoirs with the following characteristics; High-permeability formations conducive to gas mobility, Reservoirs with remaining oil saturation and suitable pressure and temperature conditions and Presence of structural or stratigraphic traps to contain the injected gas.

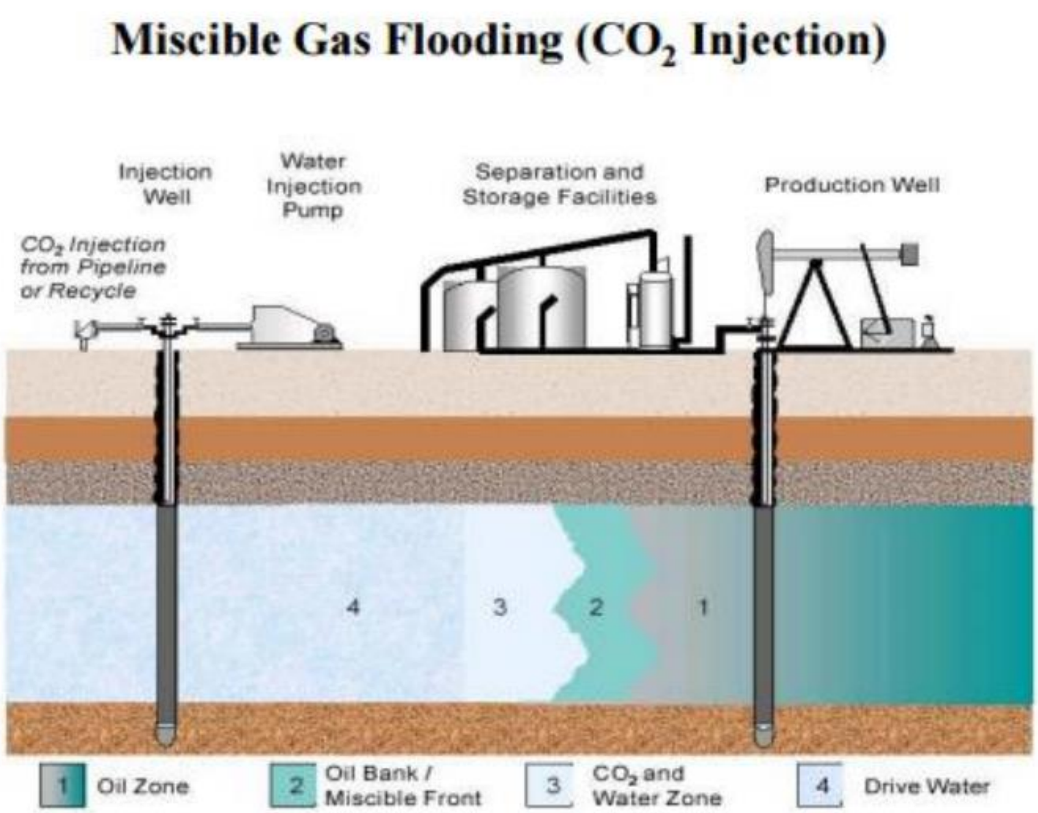


Fig 2- 0-7CO2 Gas injection

2.2.3.3 CHEMICAL RECOVERY

Chemical enhanced recovery is the method used to extract oil from the reservoir by altering the properties of the oil or reservoir rock through the injection of chemicals. Chemical enhanced recovery works based on four main mechanisms, these are interfacial tension reduction, wettability alteration, viscosity reduction and alkaline flooding. Interfacial tension reduction involve injecting surfactants to reduce the interfacial tension between oil and water promoting oil mobilization and displacement. Wettability alteration mechanism deals with injecting chemicals that can alter the wettability of rocks, making them more water-wet or oil-wet thereby improving oil displacement and recovery efficiency.

Viscosity reduction mechanism is when polymers or solvents are used to reduce oil viscosity making it to flow more readily. Lastly, alkaline flooding involves alkaline agents reacting with the acidic components of the reservoir creating emulsions that flow better. Chemical recovery is beneficial because it is effective for various oil types and reservoir conditions. Some challenges that may encountered using chemical recovery are the environmental risks that the chemicals being used may pose. Another challenge that may be encountered is the fact that it is cost intensive.

2.3 CO2 ENHANCED OIL RECOVERY

As the global energy landscape undergoes a transformative shift, the oil and gas industry faces a crucial challenge: maximizing resource extraction while minimizing environmental impact. In this context, CO2 Enhanced Oil Recovery (CO2 EOR) emerges as a technology brimming with potential. CO2 EOR leverages the unique properties of carbon dioxide (CO2) to coax additional oil from depleted reservoirs after primary and secondary recovery methods have reached their limits. The effectiveness of this technique hinges on two key mechanisms working in tandem within the reservoir.

The first mechanism, miscibility, exploits CO_2's remarkable ability to dissolve (mix) with certain types of oil, particularly heavier oils. This phenomenon, akin to thinning molasses with water, reduces oil viscosity. The resulting lower viscosity allows the oil to flow more readily towards production wells, significantly enhancing recovery rates (National Energy Technology Laboratory, 2021). However, miscibility is not a universal phenomenon; its effectiveness depends on specific oil properties and reservoir pressure.

The second mechanism involves displacement. Similar to waterflooding, injected CO_2 acts like a giant underground piston, pushing existing oil within the reservoir towards production wells. This displacement mechanism further increases oil recovery and extends the life of the reservoir (Global Energy Institute, 2017). Understanding the interplay between miscibility and displacement is crucial for optimizing CO_2 EOR project design.

Beyond these core mechanisms, research delves into additional CO_2 EOR methods. WAG (Water Alternating Gas) injection, for instance, involves alternating the injection of water and CO_2 to improve sweep efficiency and maintain reservoir pressure (Yu et al., 2006). Furthermore, research is exploring the potential of using CO_2 with other gases like nitrogen (CO_2-N_2) for enhanced oil recovery, aiming to leverage the benefits of both CO_2 and nitrogen injection (Alfarah et al., 2018).

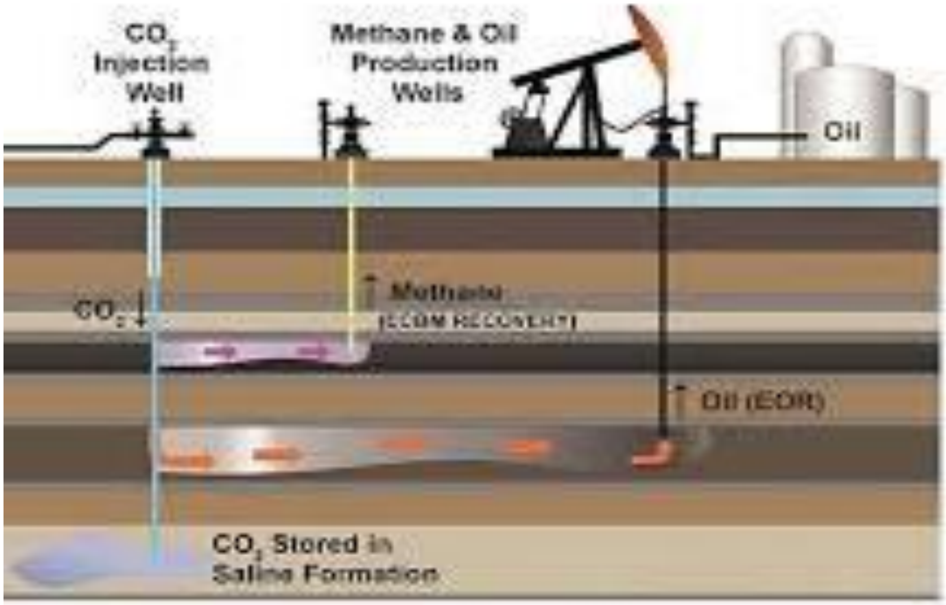


Fig 2- 0-8 CO2 Injection EOR

2.3.1 BENEFITS OF CO2 ENHANCED OIL RECOVERY

The economic benefits of CO2 EOR are undeniable. By extracting an additional 15-20% of oil compared to traditional methods, CO2 EOR offers a significant economic advantage for oil producers. This translates to increased revenue streams and potentially extends the economic viability of mature oil fields (Global CCS Institute, 2015).

However, the true intrigue lies in the environmental potential of CO2 EOR. Depending on the project design, a portion of the injected CO2 can be permanently trapped underground, effectively mitigating greenhouse gas emissions. This aspect makes CO2 EOR an attractive option in the fight against climate change (National Energy Technology Laboratory, 2021). The concept of integrating CO2 capture and storage (CCS) with CO2 EOR further enhances this environmental benefit (Zhao et al., 2010). By capturing CO2 emissions from industrial sources and injecting them into suitable geological formations for permanent storage, CO_2 EOR projects can contribute to a more sustainable future for the oil and gas industry.

2.3.2 PROBLEMS ASSOCIATED WITH CO2 EOR

Implementing CO2 EOR successfully is not without its challenges. The technical complexity of these projects necessitates specialized expertise. Careful reservoir characterization and meticulous planning are crucial to ensure compatibility with the injected CO2 and prevent potential leakage, as emphasized by Dutta and Huhn (2007). Factors like reservoir pressure, temperature, rock properties, and oil composition all play a vital role in determining the success of CO2 EOR (Lake et al., 1980) .

Furthermore, the cost of capturing, transporting, and injecting CO2 can be a significant barrier. The economic feasibility of a project heavily depends on factors like prevailing oil prices and specific reservoir characteristics. Not all reservoirs are suitable candidates (Global Energy Institute, 2017). A meticulous screening process is essential to maximize the success of CO2 EOR projects.

Environmental considerations also demand careful attention. Strict regulations and rigorous monitoring are necessary to ensure safe and responsible CO2 EOR implementation, as leakage can have detrimental environmental consequences (Zhao et al., 2010). Proper wellbore integrity and robust monitoring systems are essential to mitigate this risk. Furthermore, the environmental impact of the entire CO2 capture and transportation process associated with CCS needs to be carefully evaluated.

2.4 WATER ALTERNATING GAS METHOD

Water and gas are periodically injected into the reservoir using the same injection wells in a process known as WAG injection. WAG injection is a sub of Gas injection. The reservoir oil and the injected gas may be miscible or immiscible. One of the main goals of WAG injection is to overcome the constraints that come with using traditional gas and water flooding methods.

Although Waterflooding works well for maintaining pressure, it is prone to uneven sweeping and the omission of large oil pockets due to viscous fingering. On the other hand, high microscopic displacement efficiency can be achieved via gas injection, especially when using miscible gas. However, this technique may be hindered by channeling through high permeability zones and unfavorable mobility ratios.

WAG injection seeks to combine the benefits of both methods. Water injection helps maintain reservoir pressure and displace oil by mobilizing trapped oil ganglia. The subsequent gas injection improves sweep efficiency by creating a more favorable mobility ratio, reducing the tendency for viscous fingering. Additionally, for miscible gas (like CO_2), WAG injection allows for efficient oil displacement through solvent dilution and swelling(Christensen, J. R., et al. (2001), Jaber, A. H., et al. (2017)).

2.4.1 BENEFITS OF WATER ALTERNATING GAS ENHANCED OIL RECOVERY

Water Alternating Gas (WAG) injection has emerged as a powerful tool in the Enhanced Oil Recovery (EOR) toolbox, offering a compelling solution for maximizing production from mature oil fields. One of the most significant advantages of WAG injection is its ability to overcome the limitations of waterflooding, a common secondary recovery technique. The injected gas, often with a lower viscosity than oil, creates a transition zone with a mobility closer to oil, mitigating viscous fingering and promoting a more even sweep of the reservoir(Jaber, A. H., et al. (2017). By increasing the recovery factor, this enhanced sweep efficiency makes it possible to retrieve more oil that would otherwise stay stuck.

Compared to continuous waterflooding, WAG injection offers the advantage of requiring less water overall. This translates to a reduction in costs associated with water handling and disposal, which can be significant depending on the location and infrastructure available. Additionally, WAG injection can potentially extend the life of existing water handling facilities, delaying the need for costly upgrades or expansions(McGuire, M., et al. (2005)).

Under some circumstances, WAG injection can support an oil production strategy that is more environmentally friendly. The combined benefits of EOR and carbon capture and storage (CCS) are provided by WAG injection when CO2 is employed as the injected gas. A portion of the CO2 injected during WAG injection stays held in the reservoir, reducing its discharge into the environment and aiding in the attempt to reduce greenhouse gas emissions(Bachu, S. (2003)). This integration of EOR with CCS presents a promising avenue for the oil and gas industry to operate in a more environmentally responsible manner.

While WAG injection requires additional infrastructure for gas injection and handling, the potential economic benefits often outweigh the initial costs. The increased oil recovery achieved through improved sweep efficiency can lead to significant revenue generation. Additionally, the potential cost savings from reduced water handling and the environmental benefits associated with CO2 sequestration can further enhance the economic viability of WAG injection for specific projects(Jansen, F. E., et al. (2011)).

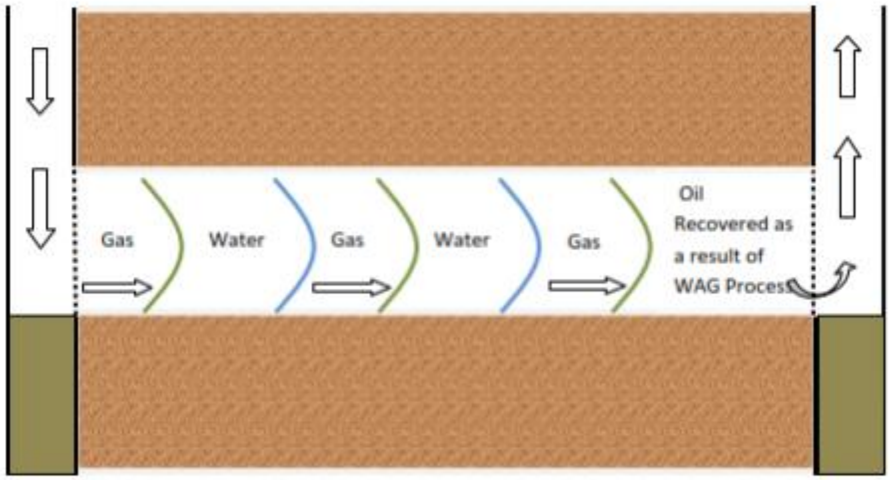


Fig 2- 0-9 Water Alternating gas injection EOR

2.4.2 PROBLEMS ASSOCIATED WITH WATER ALTERNATING GAS INJECTION

Although Water Alternating Gas (WAG) injection offers a compelling solution for maximizing oil recovery from mature fields, its implementation requires careful consideration of several challenges and complexities. Optimizing the WAG ratio—the amount of water injected relative to the amount of gas injected—is one of the main operating issues. Making the wrong ratio choice can have negative effects. When gas is injected too much it can cause viscous fingering, a phenomenon in which substantial oil pockets are avoided as the gas preferentially channels via high permeability zones. On the other hand, over-injection of water may lead to low sweep efficiency, which may leave oil unrepaired in some reservoir sections.

Another issue that occurs is infrastructural requirements for WAG injection. Implementing WAG necessitates additional infrastructure such as dedicated gas injection wells alongside water injection wells, pipelines for transporting gas to the injection points, and potentially, compression facilities depending on the gas source. These additional elements can significantly increase the upfront costs associated with WAG injection projects.

The design of the injection cycles introduces additional complication. The length of each phase in these cycles, which alternate between gas and water injection phases, has a substantial influence on recovery. Ineffective displacement can be caused by improper cycle design, which can result in undesirable mobility ratios between the injected fluids and the oil. Premature breakthrough of injected fluids, such as gas or water, to production wells can also happen, avoiding oil and lowering total recovery.

Another major problem is the corrosion i.e The breaking down or destruction of a material, especially a metal through chemical reactions. The most common form of corrosion is rusting, which occurs when iron combines with oxygen and water(Mohammed A. et al.)

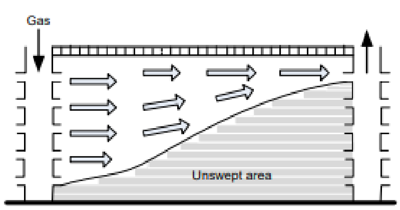


Figure 2 The gravity effect during the gas injection.

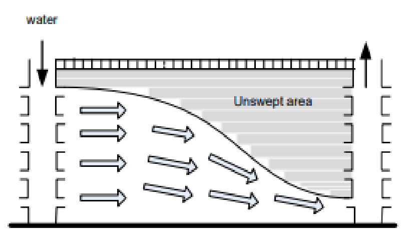


Figure 3 The gravity effect during the water injection.

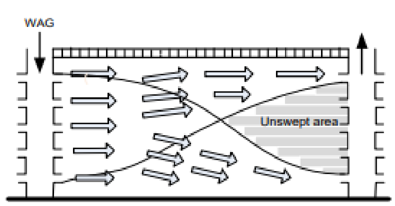


Figure 4 The gravity effect during the WAG injection.

Fig 2- 0-10 CO2, Water and WAG injection

2.5 COMPUTER MODELLING GROUP

In the ever-evolving realm of the oil and gas industry, the quest for efficient and sustainable resource extraction necessitates sophisticated tools. Computer Modelling Group (CMG) emerges as a prominent player in this arena, offering a comprehensive suite of software solutions specifically designed for reservoir simulation and subsurface engineering challenges. CMG's story began in 1978 as a research project at the University of Calgary's Chemical Engineering department, spearheaded by Dr. Khalid Aziz. Driven by the need for a robust reservoir simulator, Dr. Aziz's efforts culminated in the development of the first CMG software iteration, aided by a research grant from the Alberta government (CMG Ltd 2023). Initially focusing on heavy oil reservoir simulation, CMG progressively expanded its expertise to encompass all aspects of reservoir flow and advanced processing modelling. The company transitioned from a non-profit entity to a publicly traded company on the Toronto Stock Exchange (TSX) in 1997, solidifying its position as a leading force in reservoir simulation software. Today, CMG boasts a global presence with offices spanning several continents and a loyal customer base exceeding 570 clients in 58 countries.

CMG software offers a comprehensive suite of reservoir simulation tools catering to a diverse range of subsurface engineering challenges. Here's a glimpse into some of its core functionalities:

- **Reservoir Modeling:** CMG software empowers engineers to construct detailed geological models of subsurface reservoirs, incorporating data on rock properties, fluid characteristics, and reservoir geometry.
- **Fluid Property Prediction:** CMG's WinProp module allows for the characterization of reservoir fluids through the incorporation of PVT (Pressure-Volume-Temperature) data

and component properties, enabling accurate prediction of fluid behavior under various reservoir conditions.

- **History Matching:** This crucial process involves calibrating the reservoir model by matching historical production data, ensuring the model accurately reflects the actual reservoir behavior.
- **Primary, Secondary, and Enhanced Oil Recovery (EOR) Simulation:** CMG software allows for simulating various oil recovery methods, including natural depletion, waterflooding, and advanced EOR techniques like CO2 flooding. This simulation capability enables engineers to optimize production strategies and predict their impact on oil recovery.

Computer modelling group consists of the following sub sections:

1. GEM (CMG Equation of State Compositional Model): As discussed in detail in the previous essay, GEM is a workhorse for compositional and Equation of State (EoS) based reservoir simulation. It excels at modeling complex fluid behavior, including compositional variations and interactions between multiple hydrocarbon components. This makes it ideal for unconventional oil and gas reservoirs, gas injection processes, and CO2 EOR projects.

2. IMEX (Integrated Material EXchange): While GEM focuses on compositional modeling, IMEX is a black-oil reservoir simulator. It represents reservoir fluids as a simpler mixture of phases (oil, gas, water) and is well-suited for simulating primary, secondary, and tertiary recovery processes in conventional oil and gas reservoirs. IMEX offers a computationally efficient alternative to GEM for situations where complex compositional modeling isn't essential.

3. STARS (CMG STARS Simulator): STARS caters to thermal reservoir simulation, specializing in modeling the behavior of reservoirs undergoing thermal recovery processes like steamflooding. It incorporates advanced heat transfer modeling capabilities and can handle complex fluid properties associated with high-temperature environments.

4. CMOST (CMG Optimization and Sensitivity Analysis Tool): CMOST transcends traditional reservoir simulation by venturing into the realm of optimization and uncertainty analysis. It integrates with other CMG simulators like GEM and IMEX to help engineers optimize production strategies, identify key reservoir parameters, and assess the impact of uncertainties on production forecasts.

5. WinProp: WinProp isn't a full-fledged reservoir simulator, but rather a powerful fluid property prediction software. It plays a crucial role in CMG's workflow by allowing engineers to characterize reservoir fluids through PVT (Pressure-Volume-Temperature) analysis and component properties. This data serves as vital input for reservoir simulation with tools like GEM or IMEX.

Additional Sections:

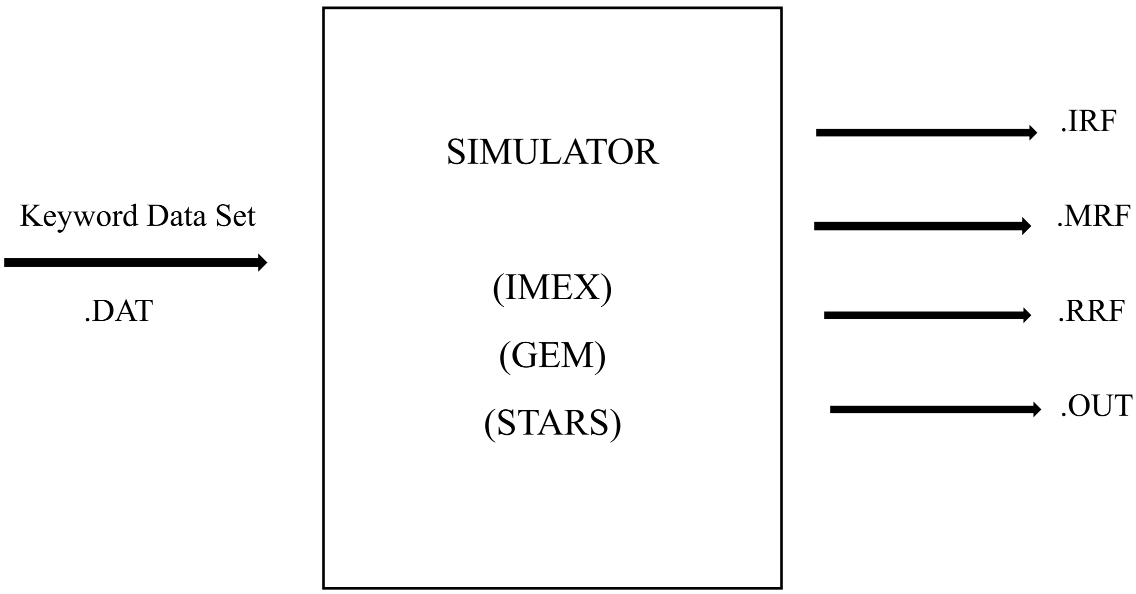
CMG offers a broader suite of software solutions beyond these core sections. These may include:

- **Builder:** A user interface for constructing reservoir models and preparing input data for various CMG simulators.
- **Eclipse Integration Tools:** Tools facilitating data exchange and interoperability between CMG software and Schlumberger's Eclipse reservoir simulator.

- **Visualization and Reporting Tools:** Software modules for visualizing and post-processing simulation results, aiding in data interpretation and decision-making.

2.5.2 WORKFLOW OF CMG SOFTWARES

The overall process to run a successful simulation is shown in the figure below;



1. **Inputting data:** A dataset with the file extension .DAT that contains all the data needed to execute the simulation. A text editor like Notepad can be used to create or edit the text file.
2. **Running the simulation:** The project dataset is inputted to one of the suitable simulator modules i.e IMEX, GEM or STARS after preparing and validating it.
3. **Outputs:** The three files with the extension .out, .irf, and .mrf with the same name as the .dat file make up the output whatever simulator is used. Three CMG programs – Findings Graph, Results 3D, and Results Report- are used to interpret the simulation results.

2.6 INTRODUCTION TO CMG STARS

The specialist reservoir modeling program CMG STARS, fully known as Computer modelling group Steam, Thermal, Advanced recovery System Simulator, was created to address the challenges posed by the intricate thermal recovery procedures found in oil and gas reservoirs. It is particularly good at simulating the behavior of reservoirs subjected to processes such as in-situ combustion (ISC), steamflooding, and steam assisted gravity drainage (SAGD).

Core Functionalities:

- **Multiphase Flow Simulation:** Like other CMG tools such as GEM, STARS can simulate the flow of various fluid phases within the reservoir, including oil, water, gas, and, crucially, steam. This feature is critical for accurately describing the dynamics of thermal recovery operations in which steam interacts and displaces reservoir fluids.
- **Phase Change Modeling:** CMG STARS excels at modeling phase shifts such as water vaporization to steam and steam condensation back into water. This enables for a more realistic modeling of steam behavior within the reservoir, as well as its effects on reservoir pressure and fluid characteristics.

Advanced Applications:

- **Steamflooding Simulation:** This is CMG STARS' most popular application. It enables engineers to develop and optimize steamflooding projects by simulating various steamflooding configurations (continuous and cyclic) and forecasting steam behavior in the reservoir.

- **In-Situ Combustion (ISC) Simulation:** CMG STARS allows for the modeling of ISC, a thermal recovery technique in which air injection ignites remaining oil in the reservoir, providing heat for future oil recovery.

2.6.2 STARS COMPONENT CONCEPT

One of the first STARS simulation design decisions to make is the type, number of components, and the phase they are found in. The following includes some STARS component concept

Reference Phase

- When a component partitions between two phases , it is necessary to define its refernce in order that the K-values are applied correctly.
- Thus a gaseous component, such as methane, which is normally found mostly in the gas phase, will be referenced to the oil phase (thus becoming an oil component) in order that the K-values are applied appropriately.

  K=Y/X

Aqueous Components examples

- Water – a standard component, which has internal default values for Density, viscosity, enthalpy, heat capacity.
- Polymer solution.

- Alkaline-surfactant solution.
- Fresh water, salt water, KCL fluid.
- Oil emulsion droplets and mobile fines.

Oleic components

These are oil-like components. They are of two types;

- Pure components
- Pseudo components

Gas Components

These are those components that normally make up the gas phase, such as solution gas, CO_2 and air. They normally have K values greater than one. There are three kinds of gas components:

- Condensable e.g CH_4 & CO_2.
- Non-condensable
- Combustion gases.

Solid Components

Examples of solid components are Coal, wax, fines, sand, coal, etc.

Dispersed components (moving particles)

Examples include Fines, Emulsions, Aqueous foams, Non-aqueous foamy oil.

CHAPTER THREE

METHODOLOGY

CASE 1- GAS(CO_2) INJECTION

- Create a simulation grid with structural data such as Porosity, permeability, thickness and others.
- Create the Pressure-Volume-Temperature data.
- Define the relative permeability data
- Set the initial reservoir Conditions
- Define the numerical section i.e simulation parameters such as time-step control e.t.c
- Create the injection well and Producer well
- Run the simulation for Co_2 injection
- Analyze results and draw out conclusions

CASE 2- WATER-ALTERNATING GAS INJECTION

Using the same model created above;

- Make changes to the injection fluid in the Injector well to be alternating Gas and water
- Run the simulation for water alternating gas injection
- Analyze the output and compare it to the results of Case 1.

All these are done using CMG STARS.

3.1 SETTING UP A CO2 INJECTION MODEL WITH CMG STARS

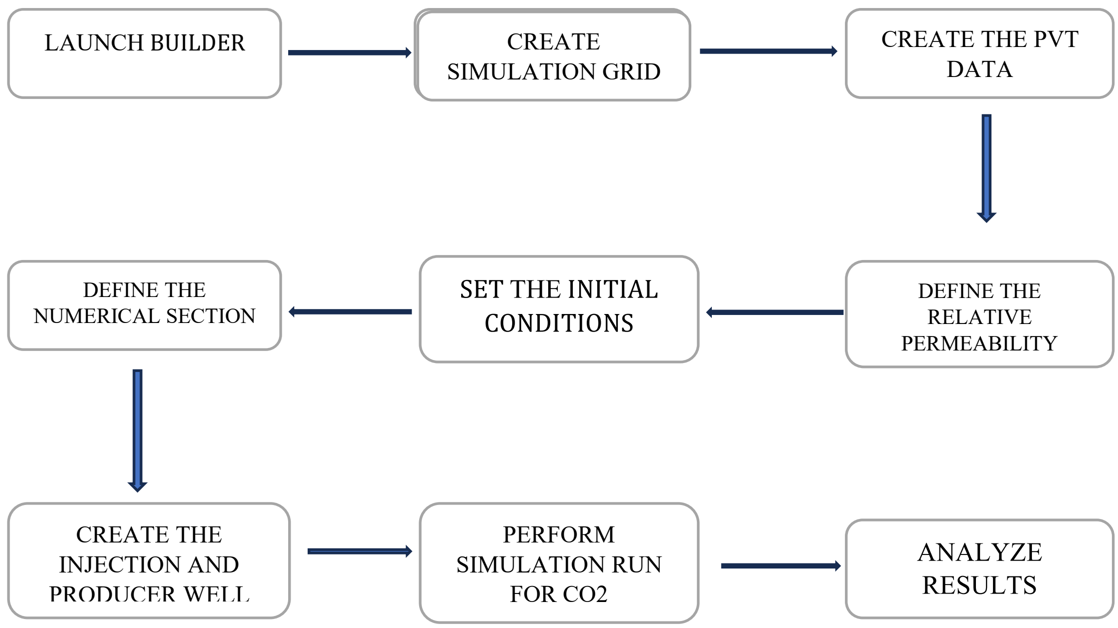


Fig 3- 1 CO2 injection model using CMG STARS

Creating a simulation grid with structural data

- Launch CMG.
- Launch Builder, select **new.**
- Select STARS as the simulator.
- Select Field Units as the working unit.
- Select Advanced and change well liquid volume to ft3(so that while the co-injection of CO2 and water is done, they will be in the same unit)
- Select single porosity model
- Select the arrow in (Reservoir) => (create grid) => (Cartesian)

- Set number of grid blocks to be 20 in the I-direction, 9 in the J-direction, and 6 in the K-direction.
- Set Block widths to be 20*150ft in I-direction and 9*100ft in J-direction.
- Select **Array properties** and set it to be the way it is described in the table below

	Grid Top (ft)	**Grid Thickness (ft)**	**Porosity**	**Permeability I (md)**	**Permeability J(md)**	**Permeability K(md)**	**Pressure (psi)**	**Temp. (F)**
Whole Grid		10		200	200	Equals I * 0.1	2000	120
Layer 1	0		0.2					
Layer 2			0.15					
Layer 3			0.08					
Layer 4			0.2					
Layer 5			0.2					
Layer 6			0.08					

Take note; The model used for this simulation does not have any form of geological interpretations, but it possesses realistic and reasonable reservoir characteristics.

Creating the PVT Data

Here the PVT data is created using the component section of the CMG STARS instead of the normal way of using Winprop.

- Go to the component section, select (Add/Edit component).

- Under the (Add/Edit component), => (Add a component), input name => **Water**
- Set the phase to be Aqueous
- Set the following values to be

  Critical pressure=3197.79psi

  Critical Temperature = 705.56F

  Molecular Weight = 18.015lb/mole

- Under the (Add/Edit component) => (Add a component), input name => **Dead oil**
- Select the phase in which it is
  - **Oleic(**i.e Oil-like) and set the following values

    Critical pressure= 0psi

    Critical temperature = 87.89 F

    Molecular Weight = 44.01 lb/mole

- Under (Add/Edit component) => (add a component), input name=> **Dead oil**
- Select the phase in which it is
  - **Gas** and set the following values

    Critical pressure = 1069psi

    Critical Temperature = 87.89psi

    Molecular weight = 44.01 lb/mole

- Under (Add/Edit component), select "Liquid phase properties/densities"

Item	**Options**	**Water**	**Dead Oil**
Density	Mass Density	62.4	50

- Under (Add/Edit component), select "liquid phase viscosities"

	Units	Water	Dead Oil
		Aqeous	Oleic
Options			
A VISC	cp	5	1
B VISC	F	0	0

- Under (Add/Edit component), select "General"

	Default	Value
Reference Pressure	14.5038psi	14.7psi
Reference Temperature	77F	120F
Surface condition pressure	14.6488	14.7

Defining The Relative Permeability Curve

- Select (rock/fluid) => create/edit rock types
- Select (new rock type)
- Go to (tools)
- Select (generate tables using correlations)
- Select apply, then OK.

Defining The Initial Conditions

For this simulation, we selected (do not perform vertical well equilibrium calculations (VERTICAL OFF)). The other method in CMG which is used to calculate vertical equilibrium is the Capillary gravity method (the conventional approach used).

Defining The Numerical Section

- Select (numerical conditions), then double click.

Key description	**Default value**
First step-size after well change (DTWELL)	0.001
Isothermal option (ISOTHERMAL)	ON
Linear solver iterations (ITERMAX)	150
Linear solver orthogonalization (NORTH)	150
Maximum average scale residual for all equations	TIGHT

- Click (Apply) then OK.

Creating And Defining The Wells.

- Select (wells)
- Right click and then click on **new**
- Under ID & TYPE; input name => Injector, input type => INJECTOR MOBWEIGHT IMPLICIT.
- Go to (constraints); under constraints, select **new**, select OPERATE.

Constraint	**Parameter**	**Limit/mode**	**Value**

OPERATE	STG Surface Gas Rate	MAX	1,000,000ft/day
OPERATE	BHP Bottom-hole pressure	MAX	4300psi

- Select Apply, then OK.
- Under ID & TYPE; input name => Producer; input type => PRODUCER.
- Go to (constraints); under constraints, select **new** , select OPERATE.

Constraint	**Parameter**	**Limit/mode**	**Value**
OPERATE	BHP Bottom-hole Pressure	MIN	2000psi

- Select Apply, then Ok.

Performing the Simulation Run For CO2 Injection

- Validation of the model is done after the above steps with STARS.
- Save the file as (Pure CO2 injection).
- Run the Simulation.

Analyzing The Results

- Select the (Pure CO2 injection.sr3) file and drag into the results app to open a new window.
- Open (Pure CO2 injection) file in the results window to view the results.
- To view the recovery factor.
- Go to plots
- Select (Sector) then (Pure CO2 injection).
- Select (Entire field)

- Then select (Oil recovery factor) and lastly select (add plot).

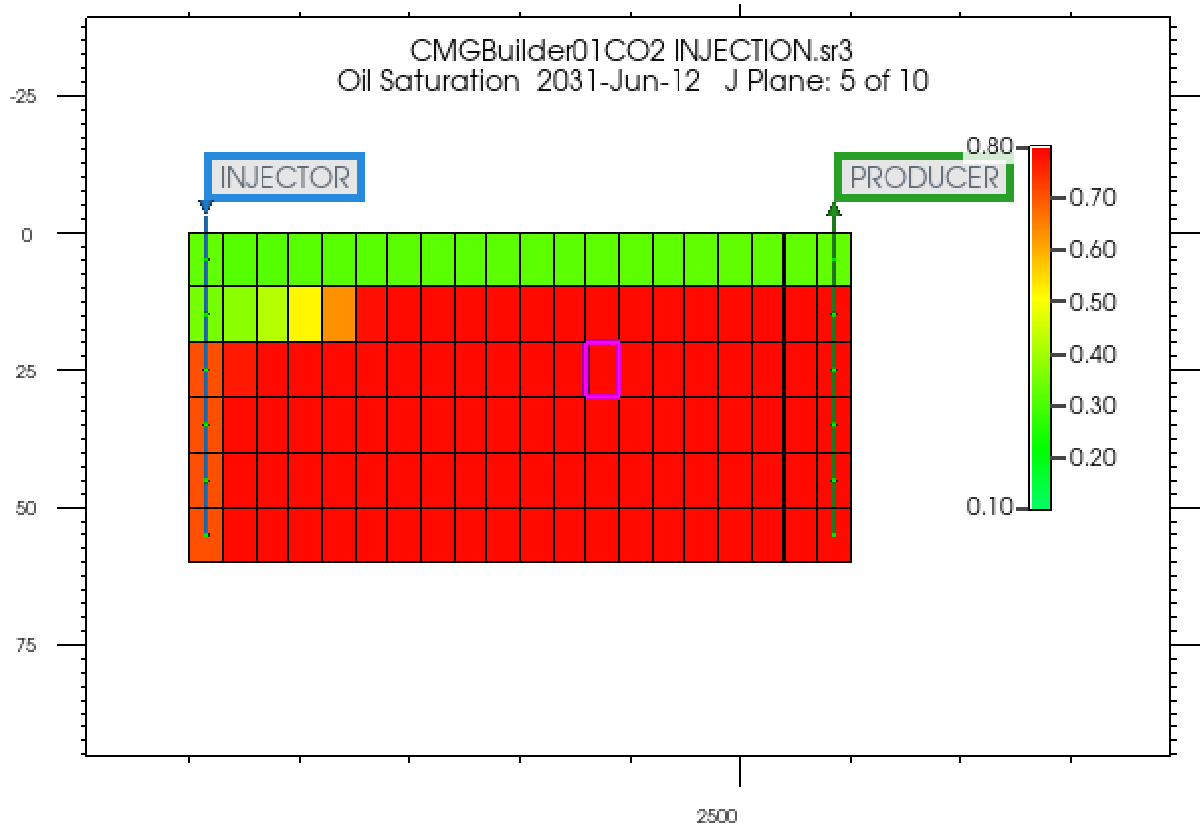


Fig 3- 2 Displacement font for CO2 injection

3.2 SETTING UP A WATER ALTERNATING GAS INJECTION MODEL USING CMG STARS

The same model as the CO2 injection model is used. Just little changes is made to the injector well.

First, another injection well is created and the injection fluid is made to be water.

Copying The Well

- Go to well on the builder interface, Click on copy well and then on injectors, click next.
- Tick **copy all perforation data,** click next.

- Tick **copy geometry**, click next.
- Under New well name (use the common suffix), use the suffix _w.
- Click next and then finish.

Copying Event

  - Click on injector I, Click copy event using filter.
  - Tick **only the copied wells** under wells.
  - Click the first date under dates.
  - Click search and add.
  - Click OK.

Changing the Fluid

- Double Click on Injector I.
- Click injected fluid and change it to cycling.
- Click Apply.

Opening The Well

- Click Injector I.
- Click Options.
- Click status, select Open.
- Click Apply.

Specifying Cycling Time For Open

- Click on open under Injector.
- Click copy event using filter.

- Select the wells injecting gas under wells.
- Under date, click clear list.
- Untick the first date.
- Click deselect all.
- Click add range of dates and change interval to one year.
- Click Ok.
- Tick **create new dates for selected wells if they do not exist.**
- Click search and apply and then click OK.

Shutting in the well

- Click on Injector I.
- Click on the date and change to six months after and then click OK.
- Click options, click status and select shut in.
- Click Apply and then OK.

Specifying cycling time for shut in

- Select the shut in and then click copy event using filter.
- Under date, click deselect all.
- Click add range of dates.
- Select six months after and then click OK.
- Under interval, change to one year and then click Ok.
- Click clear list.
- Tick **Create new dates for selected well if they don't exist.**
- Click search and add and then click OK.

Do the same operation for the water injector wells starting with shut in.

Save the file as ‘WAG injection model’. Then run the model using STARS.

Analyzing The Results

- Select the ‘water injection model. Sr3’ file and drag into the results section to open a new window.
- Open the file in the results window to view the results.
- To look at the recovery factor, go to sector, water injection model, entire field, and then finally oil recovery factor and then select (add plot).

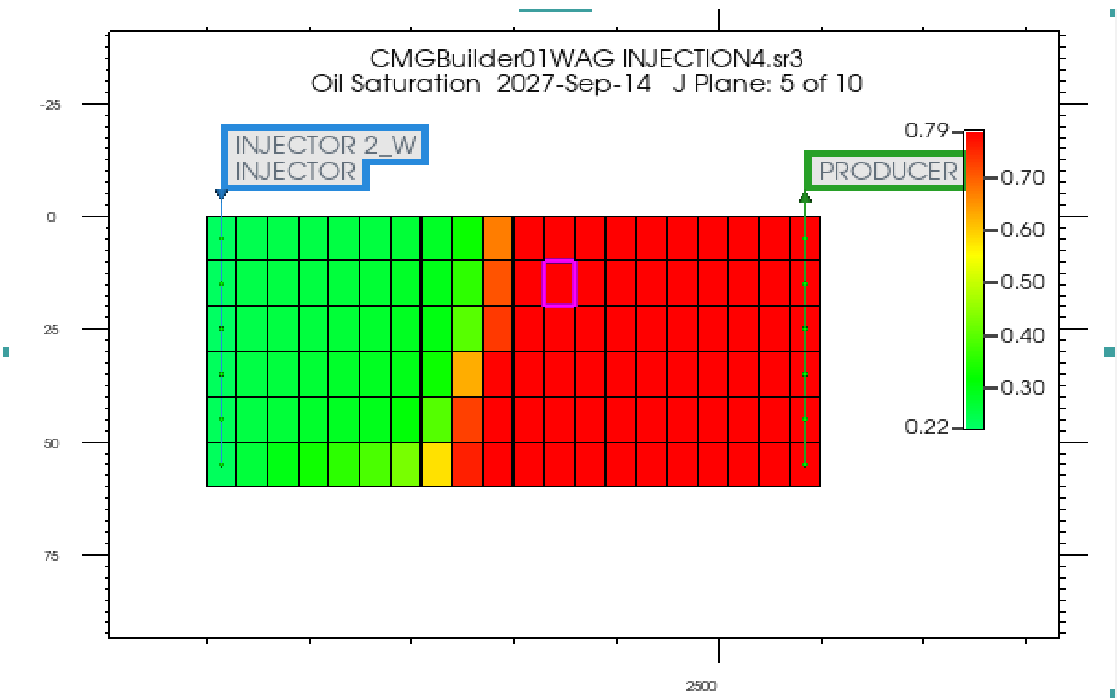


Fig 3- 3 Displacement font for WAG Injection

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 RESULTS

The figure below shows that when CO2 is injected into the reservoir, it rises to the top part of the reservoir due to its high density. This is because CO2 sometimes acts like a liquid under super-critical conditions; the recovery factor obtained from the CO2 injection gives about 15% of recovery.

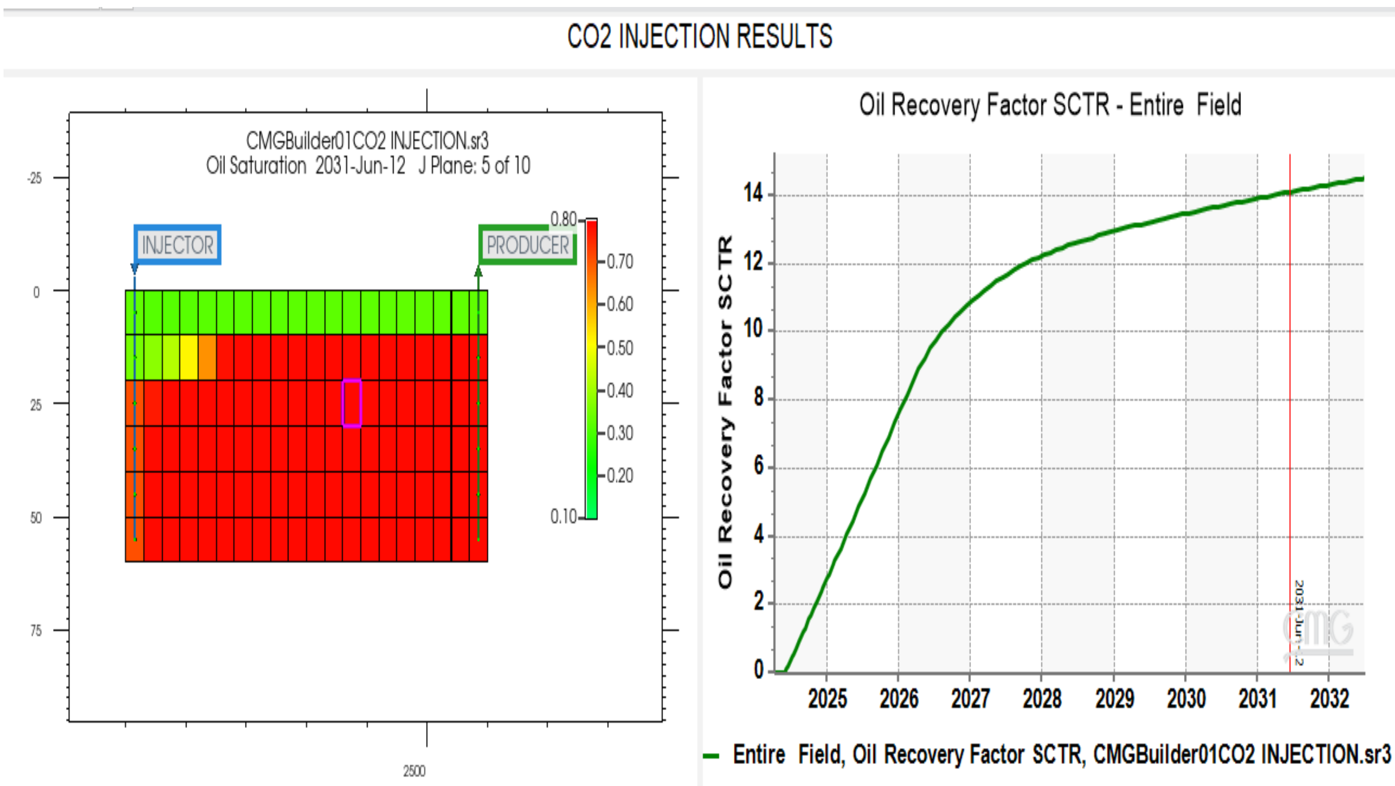


Fig 4- 1 Results for CO2 Injection

The figure below shows that when Water alternating gas injection is done on the reservoir, ,the water moves to the bottom of the reservoir and moves most of the oil as a result of high sweep efficiency. The gas also reduces the viscosity of the oil and increases the ease at which the oil flows. The recovery factor obtained from the WAG injection gives us about 55% recovery.

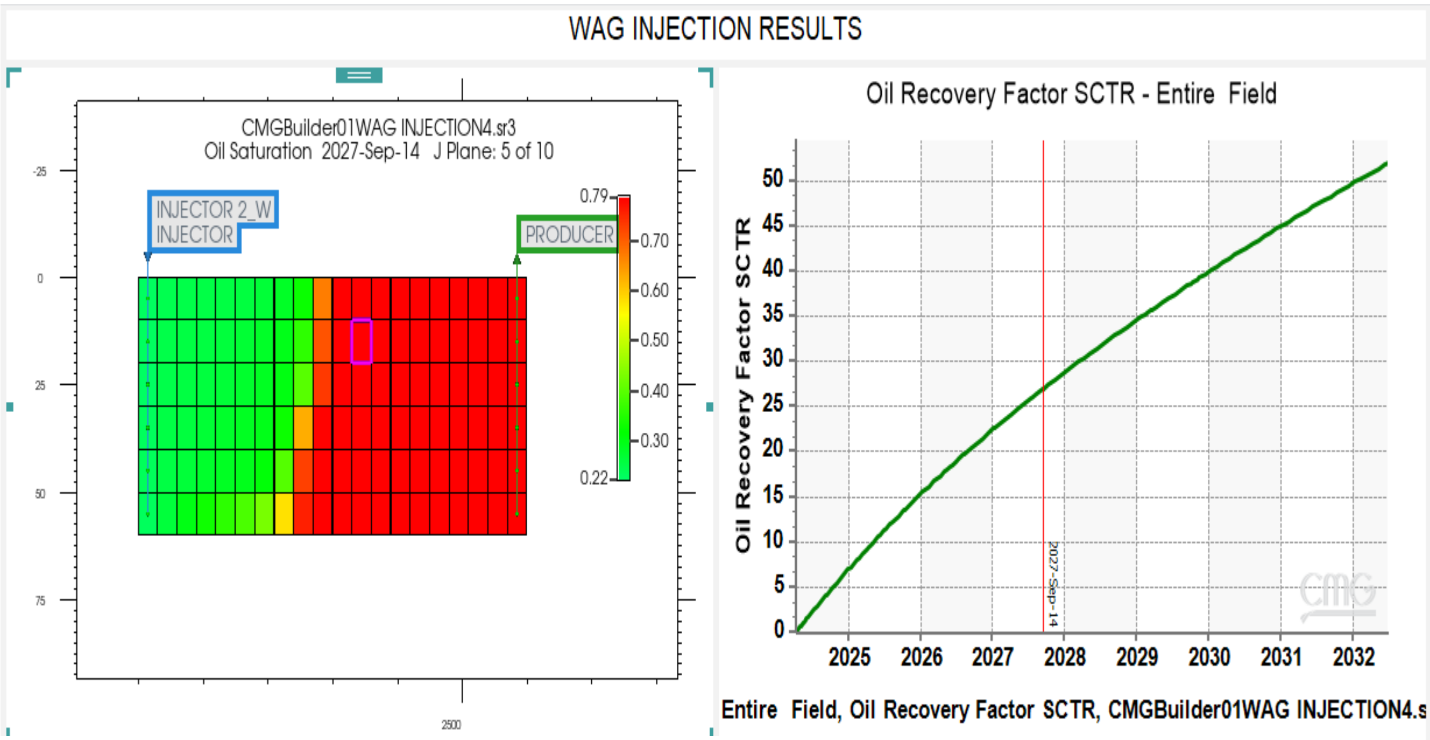


Fig 4- 2 Results for WAG Injection

4.2 DISCUSSION OF RESULTS

The comparative analysis of CO2 injection and Water alternating gas on an oil reservoir revealed significant differences in oil recovery between the two methods. In particular, WAG injection yields higher oil recovery with a recovery factor of 55% compared to CO2 injection with a recovery of 15%. These findings underscore the effectiveness of WAG injection as an EOR technique for maximizing oil recovery from reservoirs.

Several factors likely contributed to the higher oil recovery observed with WAG injection. The alternating injections of water and gas in the WAG process improved the sweep efficiency and enhanced the displacement of oil within the reservoir. Also, the intermittent injection of water facilitated better contact between the injected fluid and the reservoir rock, promoting further oil recovery.

The findings of this study aligns with previous literatures on CO2 and WAG injection, which has consistently shown the potential for WAG injection to outperform CO2 injection in certain reservoir conditions.

Some factors that might have affected CO2 injection are gravity segregation, reservoir heterogeneity(i.e variations in permeability), viscous fingering, poor sweep efficiency and high mobility ratio of CO2. The above mentioned factors cause a reduction in macroscopic sweep efficiency even though the microscopic sweep efficiency may be high.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.1 CONCLUSION

Our comparison of the CO_2 gas injection and the Water alternating gas injection models showed that Water alternating gas injection is a better alternative to produce from the reservoir as it can be seen that there is a large difference between the recovery factors of both with that of CO_2 being 15% and that of water alternating gas being about 55%.

Water alternating gas is also better because it combines the sweep efficiency of water and the reduction of viscosity property of CO_2.

5.2 RECOMMENDATIONS

- A thorough geological characterization of the reservoir should be done to optimize WAG injection performance. Also, based on the characterization, suggest strategies for well placement and injection pattern design to ensure efficient sweep of the reservoir and maximise oil displacement by both water and gas phases.
- Conduction of WAG pilot tests to determine optimal water gas ratio and injection cycle for the specific reservoir conditions. This data helps to fine-tune the WAG injection strategy and ensuring its effectiveness.
- Development of a robust monitoring and surveillance plan to track WAG injection performance should be done.

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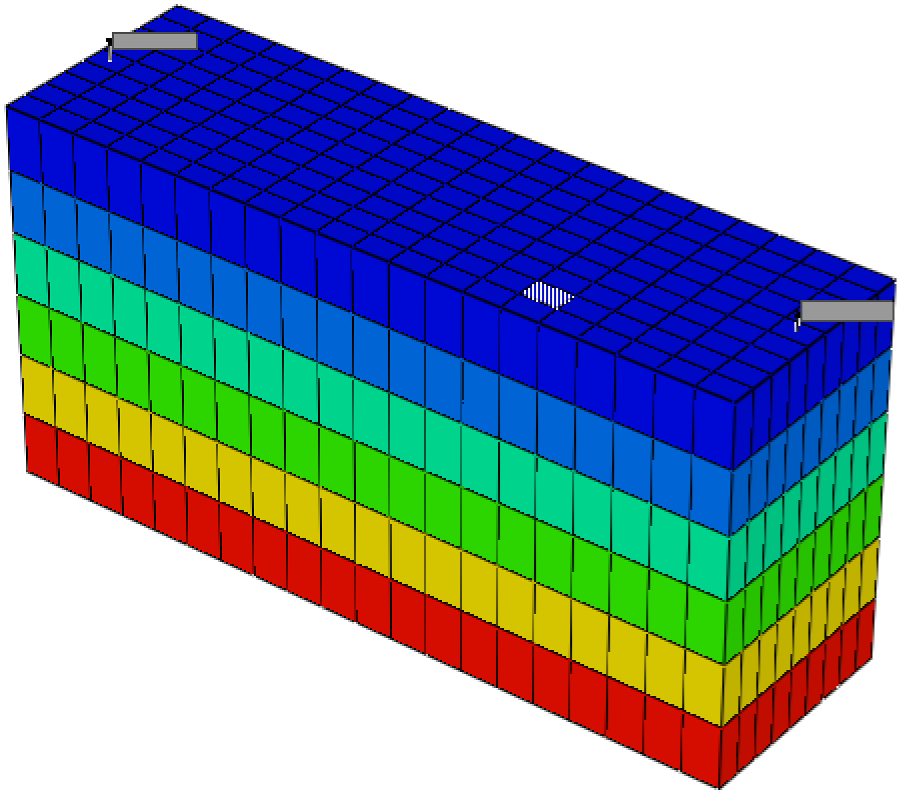
APPENDIX



App 1 Reservoir model