Enhancing Oil Recovery in a Carbonate Reservoir through Polymer Injection

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***Abstract*— Enhancing oil recovery in carbonate formations with significant remaining reserves is challenging due to inherent obstacles such as natural fractures and heterogeneity of the rock. These factors are crucial in selecting the most effective approach for enhanced oil recovery (EOR). Among various options, polymer injections have demonstrated high efficiency and are considered a favorable choice for EOR in carbonate reservoir deployment. The main objective of this study is to identify the optimal polymer injection scenario that maximizes oil recovery. To achieve this, the research employs the black oil modeling and simulation technique to evaluate the sensitivity of specific scenarios. Multiple polymer concentrations are introduced into the simulator, and the resulting oil and gas production responses are documented.**

Keywords—carbonate formations; natural fractures; reservoir heterogeneity; polymer injection; simulation

I. Introduction

In reservoirs driven by solution gas drive or gas cap drive, water or chemical injections can have a positive effect. However, in the case of significant gas injection, it can overpower the fluid being displaced. Whether the reservoir operates under a combined driving mechanism or not, it is crucial to monitor its connection with the aquifer. The introduction of polymer injections can be employed to selectively block the entry of gas into naturally fractured reservoirs, thereby maintaining reservoir pressure and stabilizing oil production. In contrast, the impact of polymer or water injections is minimal, and if a substantial gas cap exists, gas injection alone will not significantly enhance oil production.

A. Naturally Fractured Formation

Naturally fractured reservoir has unique properties, namely having two flow media that occur in the production mechanism. The McNaughton & Garb method is a method commonly used to classify naturally fractured reservoirs. Reservoir classification using the McNaughton & Garb method is quite easy to determine based on core analysis and interpretation of well testing data.

According to the McNaughton and Grab categorization, reservoir types A, B, and C are classified based on their characteristics related to matrix storage capacity, fracture porosity, recovery aspect, and flow rate. Let's break down each type:

- Reservoir Type A: Possesses a substantial matrix storage capacity, meaning that the rock matrix itself has the ability to store a significant amount of fluid. Fracture porosity contributes only around 10% of the total porosity, indicating that the fractures in the rock are not the primary storage spaces for fluid. During drilling operations, this type of reservoir frequently causes lost circulation issues. Lost circulation refers to the situation where drilling fluids escape into the formation instead of circulating back to the surface, which can lead to difficulties in maintaining the drilling process. This type of reservoir tends to have a low recovery aspect, especially if the matrix permeability (the ability of fluid to flow through the rock matrix) is high. It means that extracting a significant amount of fluid from this type of reservoir can be challenging.

- Reservoir Type B: The fluid in this type of reservoir can be stored in both the matrix of pores and fractures. The fractures contribute to a portion of the fluid storage. If this type of reservoir is supported by a high matrix permeability, meaning that the rock matrix has good fluid flow characteristics, it can result in a reservoir with an elevated rate of flow and recovery. In other words, fluid extraction from this type of reservoir can be more efficient compared to Type A.

- Reservoir Type C: In this type of reservoir, fractures play a crucial role in holding nearly all of the fluid. The matrix storage capacity is relatively low compared to the other types. Initially, a reservoir of this type can provide a high flow rate due to the presence of fractures that allow fluid to flow easily. However, over time, the flow rate might decline dramatically to a critical point or become inefficient. This decline can be attributed to factors such as reservoir pressure depletion or the presence of inefficient fractures that restrict fluid flow.

According to the Mc Naughton and Grab categorization, reservoir type A is going to possess a substantial matrix storage capacity, with fracture porosity contributing only around 10% of total porosity. During drilling operations, this sort of reservoir frequently causes lost circulation issues. This sort of reservoir will also have a low recovery aspect, especially if the matrix permeability is high. The fluid can be stored in the matrix of pores and almost balanced fractures are seen in the reservoir of type B. If this is supported by a high matrix permeability, a reservoir having an elevated rate of flow and recovery will result. The fractures will hold nearly all of the fluid in a reservoir of type C. This sort of reservoir can initially give a high flow rate, but in a short period of time, the flow rate might decline dramatically to a critical point or become inefficient.

B. Polymer Injection

Polymer injection is indeed a method used to enhance oil recovery by improving the characteristics of the injected fluid. The primary objective is to increase the efficiency of water flooding, which is a common technique for reservoir pressure maintenance and secondary oil recovery. I'll address your points below:

- Polymer injection as increased water injection: Polymer injection can be seen as a form of enhanced water injection. By incorporating polymers into the injection water, the fluid's properties are modified to enhance its effectiveness in displacing and recovering oil from the reservoir. The polymer additives serve various purposes such as increasing viscosity, altering mobility control, and improving sweep efficiency.
- Improved oil recovery: Compared to conventional water injection, polymer injection has the potential to significantly improve oil recovery. The use of polymers alters the flow behavior of the injected water, making it more favorable for displacing oil and increasing the sweep efficiency in the reservoir. The viscosity increase provided by polymers can help reduce water channeling and fingering effects, leading to better conformance and displacement of oil.
- Complexity and lack of understanding: The process of polymer injection for enhanced oil recovery is indeed complex and not fully understood. The interaction between polymers and reservoir fluids, as well as the rock matrix, is intricate and can vary depending on the specific conditions of the reservoir. Factors such as polymer selection, concentration, and injection strategy need to be carefully considered and optimized for each reservoir to achieve the desired results.
- Water permeation and polymer benefits: In reservoirs where water tends to permeate the oil, leading to water production and reduced displacement efficiency, polymer injection can be beneficial. When polymers are dissolved in the injection water, they act as thickening agents, reducing water mobility and restricting its access to the oil phase. This helps to mitigate water breakthrough, increase the displacement efficiency of oil, and improve the overall recovery.
- Reservoir heterogeneity and mobility ratio: Reservoir heterogeneity, which refers to variations in rock properties and fluid distribution within the reservoir, is an important factor to consider when implementing polymer injection. The presence of permeability variations and high permeability channels can affect the success of polymer flooding. Additionally, the mobility ratio, which compares the mobility of injected water to that of the reservoir oil, should be carefully evaluated to ensure that polymer injection is an appropriate and effective technique for a given reservoir.

C. Drive Mechanism

The primary force or mechanism that propels the hydrocarbons through the reservoir and towards the production wells. It plays a crucial role in determining the overall recovery efficiency of the reservoir. The three main drive mechanisms in oil and gas reservoirs are:

- Solution Gas Drive: This mechanism relies on the expansion of gas dissolved in the oil as pressure decreases. The gas expansion creates a driving force that helps push the oil towards the production wells.
- Gas Cap Drive: In reservoirs with a natural gas cap, the pressure of the gas cap acts as the driving force, pushing the oil towards the production wells.
- Water Drive: In reservoirs containing an aquifer, the water influx from the aquifer creates pressure that displaces the oil towards the production wells. This mechanism is commonly referred to as a water drive.

D. Mobility Ratio

The mobility ratio is a dimensionless parameter that quantifies the relative mobility of the displacing fluid (e.g., water or gas) compared to the displaced fluid (e.g., oil). It is calculated as the ratio of the viscosity of the displacing fluid to the viscosity of the displaced fluid. The mobility ratio is an indicator of the ease with which the displacing fluid can move through the reservoir compared to the oil.

When the mobility ratio is less than one, it means that the displacing fluid is more viscous or less mobile than the oil. This situation is often referred to as a favorable mobility ratio, as it indicates that the displacing fluid will tend to sweep the oil effectively and improve the overall oil recovery.

On the other hand, when the mobility ratio is greater than one, it means that the displacing fluid is less viscous or more mobile than the oil. This situation is often referred to as an unfavorable mobility ratio, as it indicates that the displacing fluid may override or bypass the oil, resulting in poor oil recovery.

E. Determination of The Location of The Injection-Production Well

Determining the location of injection-production wells is a critical step in optimizing oil recovery from a reservoir. Several considerations are taken into account to determine the placement of these wells:

- Utilization of Existing Wells: Prior to considering new wells, the capacity of the existing wells is maximized during the injection phase. This means that the injection process makes use of the available production wells to their full extent.
- Distribution Map of Remaining Reserves: A distribution map of the remaining crude oil reserves is used to identify areas in the reservoir that have significant amounts of untapped oil. The focus is on locating additional production wells in areas with large residual oil reserves, as these locations offer the potential for higher oil recovery.
- Iso-Permeability Maps: Iso-permeability maps are used to assess the permeability distribution within the reservoir. These maps provide insights into the flow direction of fluids, including the injected fluid and the displaced oil. By analyzing the iso-permeability maps, the flow patterns can be determined, and efforts can be made to prevent premature breakthrough, where the injected fluid bypasses the target oil zone and reaches the production wells too soon.

By considering the distribution of remaining reserves and using iso-permeability maps to understand flow dynamics, the location of injection-production wells can be strategically determined. This approach aims to maximize oil recovery by targeting areas with significant untapped reserves while optimizing fluid flow patterns to enhance sweep efficiency within the reservoir.

F. Determination of The Injection-Production Well Pattern

When determining the injection-production well pattern, the goal is to design an efficient sweeping pattern that can enhance the oil recovery factor. Several factors need to be considered in this process:

- Formation Homogeneity: The homogeneity of the formation, which refers to the distribution of permeability in the lateral and vertical directions, plays a crucial role in selecting the well pattern. The level of homogeneity influences the flow paths and the effectiveness of fluid displacement.
- Reservoir Rock Structure: The structure of the reservoir rock, including faults, slopes, and size, needs to be taken into account. These factors affect the placement and arrangement of injection and production wells to ensure optimal fluid flow and sweep efficiency.
- Existing Wells: The location and distribution of existing wells in the reservoir should be considered when designing the well pattern. The new injection and production wells should complement the existing ones to maximize oil recovery.
- Topographic Features: The topography of the area surrounding the reservoir may influence the well pattern design. The presence of hills, valleys, or other physical features can affect the placement and alignment of injection and production wells.
- Economic Variables: Economic considerations, such as drilling costs and operational feasibility, also play a role in determining the well pattern. The selected pattern should be cost-effective and practical to implement.

Commonly used injection-production well patterns include:

- Direct Line Drive: Injection and production wells are arranged in a straight line, with each injection well positioned opposite a production well. The spacing between similar wells (a) and different wells (d) is important in this pattern.
- Staggered Line Drive: Injection and production wells are arranged in a line, with equal distances between them. The line is typically shifted laterally by a distance of a/2.
- Four Spot: This pattern consists of three injection wells arranged in a triangular shape, with a single production well located at the center.
- Five Spot: The five-spot pattern is widely used in waterflooding. It involves injection wells arranged in a rectangular shape, with a single production well positioned at the center.

- Seven Spot: In the seven-spot pattern, injection wells are placed at the corners of a hexagonal shape, and the production well is positioned at the center.

G. *Determination of Injection Rate*

The determination of the injection rate plays a crucial role in the success of water injection operations. The following factors are considered when determining the injection rate:

- Closed Well Pattern and Mobility Ratio: The injection rate mentioned here pertains to wells arranged in a closed pattern and assumes a mobility ratio (R) of one. The mobility ratio represents the ratio of the viscosity of the displacing fluid (water) to the viscosity of the displaced fluid (oil).
- Pressure Difference: The injection rate is determined by the pressure difference between the injection pressure at the bottom of the well and the reservoir pressure. This pressure difference drives the flow of water into the reservoir.
- Optimal Injection Rate: The optimal injection rate is the amount of water injected that compensates for reservoir drainage while maintaining a stable reservoir pressure. The injection rate is designed to sustain a reasonably steady and high reservoir pressure.
- Reservoir Characteristics: The initial water injection rate is influenced by factors such as effective permeability, viscosity of oil and water, sand thickness, well radius, reservoir pressure, and applied water pressure. These characteristics determine the behavior of the injection well as water enters the reservoir.
- Resistance to Flow and Water Quality: As water spreads into the reservoir, the resistance to flow increases. The quality of the injection water is also a consideration. Both factors impact the injection well's performance and efficiency.
- Profit Maximization and Fracture Pressure: The injection pressure is chosen to maximize profitability, with a lower limit of injection pressure ensuring oil production. The upper limit of injection pressure is associated with the pressure that initiates fracturing in the reservoir.

The determination of the injection rate requires careful consideration of these factors to ensure optimal reservoir performance, maximize oil recovery, and maintain the stability of the reservoir pressure.

H. *Reservoir Simulation Concept*

This study utilizes tNavigator software, developed by Rock Flow Dynamics, for reservoir simulation. Reservoir simulation plays a crucial role in understanding and predicting the behavior of a reservoir under various production scenarios. It involves the use of specialized software to create models that accurately represent the reservoir's chemical, physical, and thermal properties and behavior. These models aid in simulating reservoir performance and evaluating different production conditions.

Reservoir modeling can be categorized into two types: physical models and mathematical models. Physical models utilize tangible objects or systems to observe and analyze reservoir behavior, while mathematical models rely on mathematical formulas and equations to represent the reservoir's characteristics.

The main objective of reservoir modeling is to assess the reservoir's behavior and performance under different production conditions. This is achieved by inputting relevant data into the reservoir simulation software, which processes the information and generates simulation results. Reservoir simulation serves several purposes, including:

- Estimating Initial Reservoir Reserves: Reservoir models help determine the initial hydrocarbon volume present in the reservoir, providing vital information for field development planning.
- Analyzing Fluid Movements: Simulation models enable the examination of fluid flow patterns within the reservoir, facilitating the understanding of fluid distribution and displacement during production.
- Developing Production Schedules: Reservoir simulation assists in designing optimal production schedules by evaluating various production strategies and identifying the most effective approach.
- Assessing Injection Effects: Simulation models help assess the impact of fluid injection on crude oil production, enabling engineers to optimize injection strategies for enhanced oil recovery.
- Evaluating Reservoir Constraints: Reservoir simulation aids in estimating reservoir limitations and drainage areas, supporting informed decision-making in reservoir management.

Reservoir modeling heavily relies on specialized software called reservoir simulators. These simulators have become standard tools for developing field development plans across primary, secondary, and tertiary recovery stages. Prior to implementing a field development plan in an actual reservoir, reservoir simulation software allows for performance estimations and optimization studies, contributing to an enhanced overall field development process.

II. Research Methodology

The research methodology for this study involved the following methodologies:

- Reservoir Simulation: The primary methodology employed in this study was reservoir simulation. The tNavigator software by Rock Flow Dynamics was utilized to simulate the behavior of the carbonate reservoir under different scenarios.

- Screening Criteria for Polymer Selection: Screening criteria were established to determine the most suitable polymer for injection. Factors such as viscosity, compatibility with reservoir fluids, and potential for adsorption were considered in the selection process.
- Polymer Data Processing from Rocks: Data obtained from rock samples, including core analysis and laboratory experiments, were processed to obtain essential polymer properties. This data was incorporated into the reservoir simulation model to accurately represent the behavior of the polymer in the reservoir.
- Well Injection Constraints: Constraints were set for the injection wells to ensure the optimal placement and control of injection fluids. These constraints considered factors such as well location, perforation intervals, and injection rates.
- Variation in Injection Fluid Concentration: The concentration of the injection fluid, specifically the polymer, was varied in the simulation model. Different levels of polymer concentration were tested to evaluate their impact on oil recovery.
- Forecasting and Analysis: The simulation results were used to generate forecasts and evaluate various scenarios. The behavior of the reservoir, including fluid flow patterns, pressure distribution, and oil recovery, was analyzed under different conditions. This analysis provided insights into the effectiveness of polymer injection for enhancing oil recovery in the carbonate reservoir.

The combination of reservoir simulation, screening criteria development, polymer data processing, well constraints, concentration variation, and forecasting and analysis allowed for a comprehensive evaluation of the polymer injection technique in the carbonate reservoir. These methodologies facilitated a deeper understanding of the reservoir behavior and the potential for improving oil recovery through polymer injection.

III. Finding and Discussion

This polymer input is utilized to transfer the reservoir's adsorption and polymer products to the polymer. Furthermore, the input is accomplished by filling up the viscosity table against the polymer concentration. The injection constraint is used to establish a well restriction, and the constraint used in this work is directed at injection wells with three variables, where the two fixed variables are injection rate and bottom hole pressure (BHP), and the variable injection is polymer concentration.

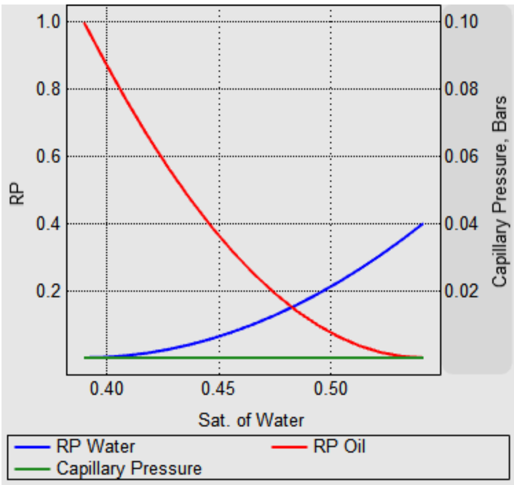


Fig. 1 Water Saturation

Fig. 1 displays a plot or diagram representing water saturation values in a reservoir. Based on the information provided, the plot indicates that the water saturation is 0.4827 which is less than 0.5 throughout the reservoir. This means that in the given reservoir, less than half of the pore space is filled with water, while the remaining pore space is occupied by other fluids, such as oil or gas.The plot likely consists of data points or a curve representing different locations or depths within the reservoir. The water saturation values associated with each data point or depth are below 0.5, indicating that the reservoir is predominantly composed of hydrocarbons rather than water. A water saturation below 0.5 suggests that the reservoir has a significant amount of hydrocarbons in place, which can be of economic interest for oil and gas production. It implies that there is potential for extracting and recovering the hydrocarbons from the reservoir.

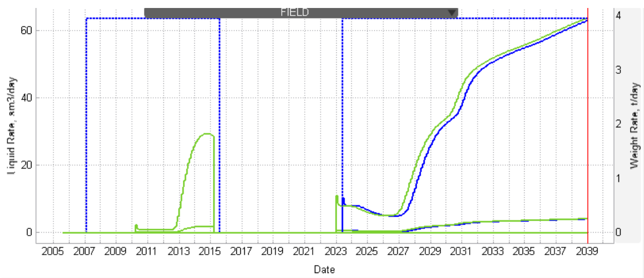


Fig. 2 Rate Production of Water in Various Scenarios

Fig. 2 illustrates the production rate of water in different scenarios, including waterflood and polymer injection at concentrations of 500 ppm, 750 ppm, and 1000 ppm. The data presented in the figure indicates that there is no significant difference in the production rates of water among these scenarios. In the base case scenario, the water production rate is reported as 4.041 m^3/day. The other scenarios involving polymer injection at concentrations of 500 ppm, 750 ppm, and 1000 ppm yield water production rates of 25.74 bbl/day. The incremental increase in polymer concentration (from 500 ppm to 1000 ppm) does not result in a noticeable difference in the water production rates compared to the base case. This suggests that the polymer injection scenarios evaluated in this study do not significantly impact the production rate of water in the reservoir.

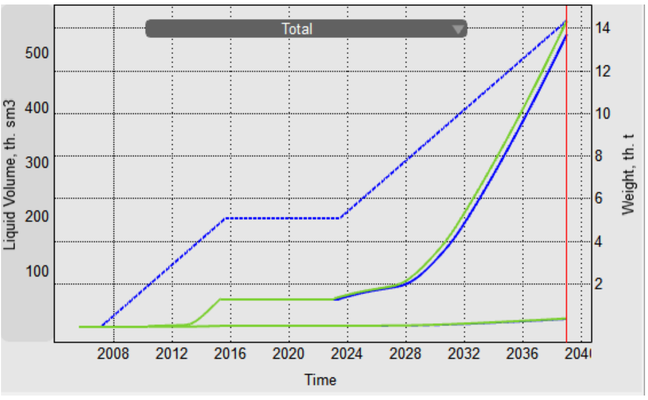


Fig. 3 Cumulative Production of Water in Various Scenarios

Fig. 3 depicts the cumulative production of water in different scenarios, including waterflood and polymer injection at concentrations of 500 ppm, 750 ppm, and 1000 ppm. The figure shows the following cumulative water production values:

- Base case cumulative water production: 89,512.529 bbl
- Cumulative water production in other scenarios: 93,666.157 bbl

This indicates that the cumulative water production in the other scenarios is about 4.6% higher compared to the base case scenario. From these results, it can be observed that the cumulative water production in the other scenarios (with polymer injection) is higher compared to the base case scenario. The increase in cumulative water production in the polymer injection scenarios suggests that the presence of polymers in the injected fluids has affected the displacement and extraction of water from the reservoir. The polymer injection, at concentrations ranging from 500 ppm to 1000 ppm, has likely improved the sweep efficiency and contributed to enhanced water recovery from the reservoir. The cumulative water production values demonstrate the effectiveness of polymer injection in mobilizing and displacing water from the reservoir over the production period considered in the study. This suggests that the polymer injection scenarios have positively impacted the overall water recovery from the reservoir compared to the base case scenario.

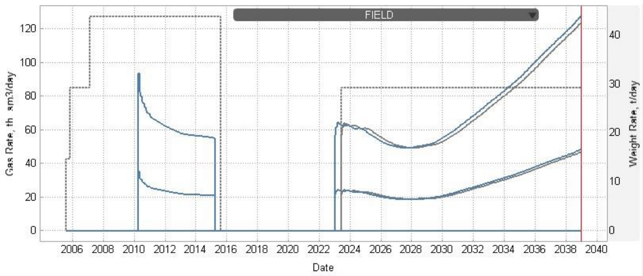


Fig. 4. Rate Production of Gas in Various Scenarios

Fig. 4 represents the rate of gas production in different scenarios, including waterflood and polymer injection at concentrations of 500 ppm, 750 ppm, and 1000 ppm. The data provided in the figure indicates the following gas production rates:

- Base case gas production rate: 1,645,381.672 SCF/day
- Gas production rates in other scenarios: 1,699,710.141 SCF/day

From these results, it can be observed that the gas production rates in the other scenarios (with polymer injection) are higher compared to the base case scenario. The increase in gas production rates in the polymer injection scenarios suggests that the presence of polymers in the injected fluids has positively influenced the displacement and extraction of gas from the reservoir. The addition of polymers, at concentrations ranging from 500 ppm to 1000 ppm, has likely improved the sweep efficiency and facilitated enhanced gas recovery from the reservoir. The higher gas production rates in the polymer injection scenarios indicate that the polymer injection technique has been effective in mobilizing and displacing gas from the reservoir. This suggests improved gas recovery compared to the base case scenario, where no polymers or water were injected.

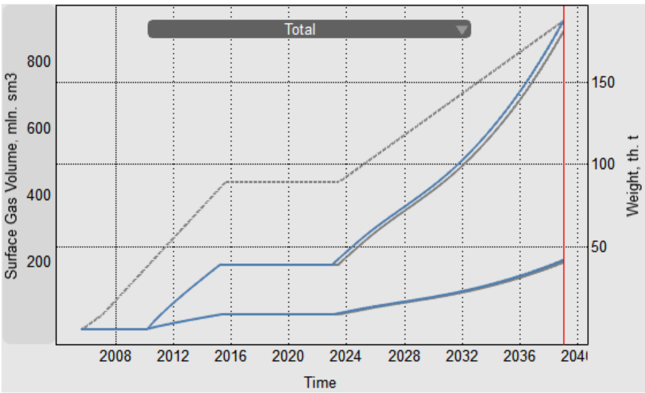
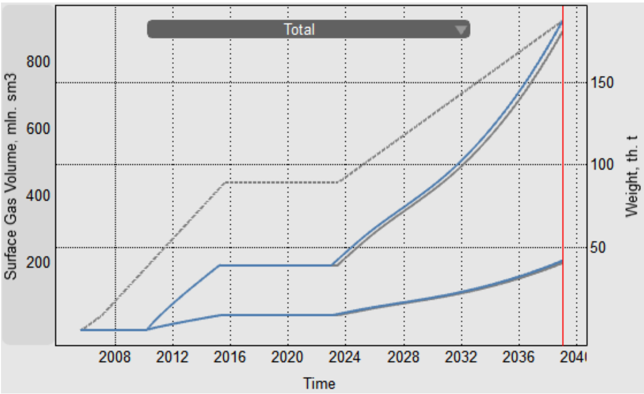


Fig. 5. Cumulative Production of Gas in Various Scenarios

Fig. 5 represents the cumulative production of gas in different scenarios, including waterflood and polymer injection at concentrations of 500 ppm, 750 ppm, and 1000 ppm. The figurer indicates the following cumulative gas production values:

- Base case cumulative gas production: 5.64 BSCF
- Cumulative gas production in other scenarios: 5.83 BSCF

This indicates that the cumulative gas production in the other scenarios is about 3.5% higher compared to the base case scenario. From these results, it can be observed that the cumulative gas production in the other scenarios (with polymer injection) is higher compared to the base case scenario. The increase in cumulative gas production in the polymer injection scenarios suggests that the presence of polymers in the injected fluids has positively influenced the displacement and extraction of gas from the reservoir. The addition of polymers, at concentrations ranging from 500 ppm to 1000 ppm, has likely improved the sweep efficiency and facilitated enhanced gas recovery from the reservoir. The higher cumulative gas production values in the polymer injection scenarios indicate that the polymer injection technique has been effective in mobilizing and displacing gas from the reservoir over the production period considered in the study. This suggests improved gas recovery compared to the base case scenario, where no polymers were injected.



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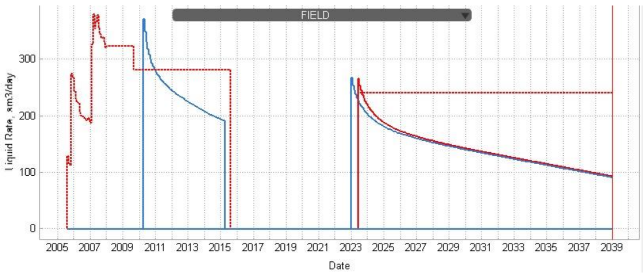

Fig. 6. Rate Production of Oil in Various Scenarios

Fig. 6 shows the rate of oil production in different scenarios, including waterflood and polymer injection at concentrations of 500 ppm, 750 ppm, and 1000 ppm. The provided data indicates the following oil production rates:

- Base case oil production rate: 585.871 bbl/day
- Oil production rates in other scenarios: 572.987 bbl/day

From these results, it can be observed that the oil production rates in the other scenarios (with polymer injection) are slightly lower compared to the base case scenario. The decrease in oil production rates in the polymer injection scenarios suggests that the presence of polymers in the injected fluids may have influenced the fluid dynamics and flow behavior in the reservoir. This could result in slightly reduced oil production rates compared to the base case scenario. The impact of polymer injection on oil production rates can be influenced by various factors, including reservoir characteristics, polymer properties, injection strategies, and the specific behavior of the reservoir fluids. While polymer injection can enhance oil recovery by improving sweep efficiency and displacement, there might be trade-offs that can affect the production rates.

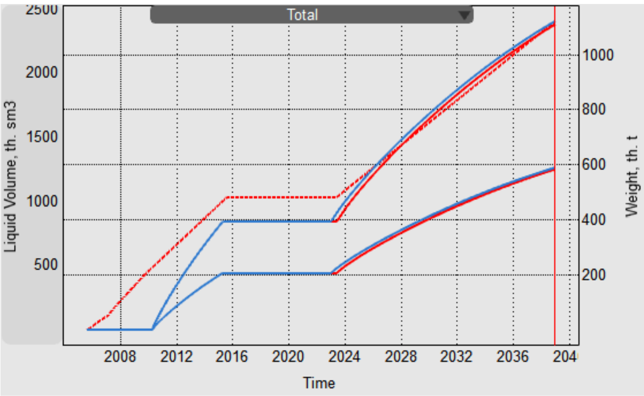

Fig. 7. Cumulative Production of Oil in Various Scenarios

Fig. 7 illustrates the cumulative production of oil in different scenarios, including waterflood and polymer injection at concentrations of 500 ppm, 750 ppm, and 1000 ppm. The provided data indicates the following cumulative oil production values:

- Base case cumulative oil production: 7.820452 MMbbl
- Cumulative oil production in other scenarios: 7.913736 MMbbl

This indicates that the cumulative oil production in the other scenarios is about 1.1% higher compared to the base case scenario. From these results, it can be observed that the cumulative oil production in the other scenarios (with polymer injection) is slightly higher compared to the base case scenario. The increase in cumulative oil production in the polymer injection scenarios suggests that the presence of polymers in the injected fluids has positively impacted the displacement and extraction of oil from the reservoir. The addition of polymers, at concentrations ranging from 500 ppm to 1000 ppm, has likely improved the sweep efficiency and facilitated enhanced oil recovery from the reservoir. The higher cumulative oil production values in the polymer injection scenarios indicate that the polymer injection technique has been effective in mobilizing and displacing oil from the reservoir over the production period considered in the study. This suggests improved oil recovery compared to the base case scenario, where no polymers were injected.

The base case scenario for the field involved producing wells from July 2005 to December 2027. However, due to a decrease in oil flow rate and an increase in gas flow rate around 2015, the decision was made to close the field. The re-production of the field is planned for June 2023 to June 2039, during which waterflood and polymer injection will be employed. In the base case scenario, the total oil output was 197.636 BSTB (Billion Standard Barrels), with a recovery factor of 1.1%. This means that 1.1% of the original oil in place (OIP) was recovered during the production period. Additionally, the gas generated during the production was reported to be 7.306 BSCF (Billion Standard Cubic Feet).

The natural fracture highlights a characteristic behavior of production rates in certain reservoirs. Initially, when production begins, the fracture contains both petroleum fluid (oil) and gas. As a result, the production rate is high due to the presence of both phases. However, over time, as production continues, the petroleum fluid in the fracture is gradually depleted, leaving only gas behind. As the petroleum fluid is used up in the initial phase of production, the proportion of gas in the fracture space increases. This leads to a significant reduction in the production rate since gas has a much lower flow rate compared to liquid phases. The diminishing availability of liquid petroleum in the fracture causes the production rate to decline substantially. Additionally, as production progresses towards the end, the reservoir pressure in the vicinity of the fracture decreases. This decrease in reservoir pressure can reach a point where it becomes insufficient to push the remaining liquid back up to the surface. Consequently, the production rate near the conclusion of production becomes very low or ceases entirely.

The optimal STW (Surface to Wellbore) constraint or injection flow rate refers to the amount of water injection that can effectively compensate for the drainage of the reservoir while maintaining stable reservoir pressure. It is important to find the right balance between injection rate and reservoir pressure to maximize oil recovery. The ideal injection pressure is typically achieved when the reservoir pressure approaches, but does not exceed, the bubble point pressure (Pb). At this pressure range, the oil in the reservoir becomes less viscous, resulting in increased oil mobility. This enhanced mobility optimizes the displacement of oil by the injected polymer solution, leading to improved oil recovery. Regarding the BHP (Bottom Hole Pressure) constraint, it is applied when the reservoir pressure is either excessive but does not exceed the initial reservoir pressure or when it is equal to the current reservoir pressure. This constraint aims to prevent excessive pressure in the wellbore, which could cause an increase in oil viscosity. Higher oil viscosity can hinder the optimization of pressure effects on oil displacement and recovery. The optimal STW constraint considers the injection flow rate, injection pressure, and bottom hole pressure to achieve an effective balance between oil recovery and reservoir stability.

Prior to reservoir modeling, it is important to conduct laboratory tests to examine the deliverability and concentration of polymers. These tests help assess how the polymers will react under reservoir conditions, taking into account rock properties and reservoir fluids. One such test involves determining the mobility ratio between the injected fluid and the reservoir fluids. This helps evaluate how the polymer's characteristics may change upon contact with the formation water or hydrocarbon fluids. The selection of polymer concentration and the arrangement of production and injection wells also play a crucial role in achieving an effective sweeping pattern within the reservoir. The goal is to ensure that the injected polymer solution efficiently displaces and sweeps the oil towards the production wells.

Based on the scenario, the polymer injection at a concentration of 500 ppm is recommended for the EOR (Enhanced Oil Recovery) Chemical Polymer technique in the "SA" field. This scenario shows the highest increase in the recovery factor (RF) compared to other scenarios, reaching 1.1%. Additionally, the total gas produced in this scenario is relatively low at 3.5%. The reduction in gas production suggests that the pressure drop within the reservoir is minimal, indicating the potential for long-term production from this field.

According to the simulation's projection, the oil production rate will reach its peak in June 2023 immediately after the well is reactivated, reaching 572.987 barrels per day (bbl/day). This peak production is attributed to the presence of fractures, which have a significant impact on the early stages of production and become more pronounced during the reactivation phase.

IV. Conclusion and Further Research

Based on the simulation results, several conclusions and suggestions can be made:

- Waterflood injection is more efficient: The research findings indicate that waterflood injection, which is a conventional method, yields similar results to various polymer injection scenarios in this carbonate reservoir. This suggests that waterflood injection can be considered a more efficient approach compared to polymer injection, as it achieves comparable oil recovery without the additional complexity and potential decrease in recovery associated with polymer injection.

- Polymer injection slightly decreases oil recovery: The simulation results show that polymer injection scenarios result in a slight decrease in oil recovery compared to the base case or waterflood injection. This suggests that the application of polymers may not provide a significant improvement in oil recovery in this particular carbonate reservoir. It is important to carefully evaluate the potential benefits and drawbacks of polymer injection, considering factors such as reservoir properties, fluid characteristics, and economic considerations.

Based on these conclusions, the further research can be made:

- Focus on optimizing waterflood injection: Since waterflood injection yields similar results to polymer injection, it is recommended to focus on optimizing the waterflood strategy. This can include optimizing injection rates, well placement, and sweep efficiency to maximize oil recovery while maintaining operational efficiency.
- Further evaluate the potential benefits of polymer injection: While the simulation results show a slight decrease in oil recovery with polymer injection, it may still be worthwhile to conduct further studies and evaluations to fully understand the potential benefits and limitations of polymer injection in this carbonate reservoir. This could involve conducting additional laboratory tests and considering variations in polymer concentrations, injection strategies, and reservoir conditions.
- Consider other enhanced oil recovery (EOR) techniques: In addition to waterflood and polymer injection, it may be beneficial to explore other EOR techniques that have shown promising results in carbonate reservoirs. This could include methods such as gas injection, chemical flooding, or thermal methods like steam injection or in-situ combustion. Evaluating alternative EOR techniques can provide a more comprehensive understanding of the reservoir's response and identify the most effective approach for maximizing oil recovery.

Acknowledgment

We would like to express our sincere gratitude for the invaluable support and assistance provided by the Petroleum Engineering Department of the Faculty of Mineral Technology at Universitas Pembangunan Nasional Veteran Yogyakarta. Their guidance and expertise have greatly contributed to the success of this study.

We would also like to extend our appreciation to Rock Flow Dynamics Kuala Lumpur, Malaysia for their support and collaboration. Their contributions in providing access to the tNavigator software and sharing their knowledge in reservoir simulation have been instrumental in the execution of this study.

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