Palacký University Olomouc

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Department of Geology

Production prediction of horizontal well from a thin oil rim using Eclipse simulator

Bachelor thesis

Ali Salar Salim

Petroleum Engineering (B0724A330002)

Fulltime study

Supervisor: Dr. Jagar Ali, Ph. D.

Advisor: Barham Sabir Mahmood, MSc.

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Anotace:

Nádrže s tenkým okrajem se obvykle týkají nádrží s platovou tloušťkou menší než 100 stop. Těžba ropy z těchto nádrží představuje problémy především kvůli přítomnosti plynového uzávěru a vodonosné vrstvy, stejně jako umístění vrtů vzhledem ke kontaktům kapaliny. . Dynamika plynového uzávěru a vodonosné vrstvy ovlivňují produkci ropy a pečlivé umístění vrtu je nezbytné pro optimalizaci obnovy a minimalizaci vlivu těchto faktorů. Tento projekt si klade za cíl předpovědět produkční výkonnost horizontálního vrtu v tenkém ropném ráfku pomocí simulátoru Eclipse. K dosažení tohoto cíle byl vytvořen model tenkého olejového ráfku pomocí simulačního softwaru ECLIPSE. Bylo simulováno a analyzováno několik scénářů zahrnujících různé injekční tekutiny, délku horizontálního vrtu, typy vrtů a strategie umístění vrtu. Tyto scénáře byly porovnány se základním případem, aby se vyhodnotila kumulativní produkce ropy, vody a plynu. Zjištění odhalují, že prodloužení délky horizontálního vrtu z 1800 stop na 2700 stop zvyšuje produkci ropy o 17,5 % (z 2745440.5 na 3225610.8 stb). Vstřikování vody horizontálními vrty vykazuje nejvyšší produkci ropy (2786540.8 stb) ve srovnání s vertikálními vrty. Vstřikování plynu dvěma vertikálními vrty však přináší dalších 20 % produkce ropy. Simulační studie navíc ukazuje, že nejúčinnější umístění vrtu nastává v hloubce 36 stop pod kontaktem plyn-olej (GOC) a 26 stop nad kontaktem voda-olej (WOC), což vede k maximální produkci ropy 2920763.5 stb. ve srovnání s jinými scénáři.

Klíčová slova: Okrajový zásobník ropy, horizontální vrt, vstřikování vody a plynu, umístění vrtu

Počet stran: 53

Počet příloh: 2

Annotation:

Thin oil rim reservoirs typically refer to reservoirs with a pay thickness of less than 100 ft. Extracting oil from these reservoirs presents challenges primarily due to the presence of a gas cap and aquifer, as well as the positioning of wells in relation to the fluid contacts. The gas cap and aquifer dynamics affect oil production, and careful well placement is essential to optimize recovery and minimize the influence of these factors. This project aims to predict the production performance of a horizontal well in a thin oil rim reservoir using Eclipse simulator. To achieve this objective, a thin oil rim model was created using the ECLIPSE simulation software. Multiple scenarios involving various injection fluids, length of horizontal well, types of wells, and well placement strategies were simulated and analyzed. These scenarios were compared against a base case to evaluate the cumulative production of oil, water, and gas. The findings reveal that extending the length of the horizontal well from 1800 ft to 2700 ft enhances oil production by 17.5% (from 2,745,440.5 to 3,225,610.8 stb). Water injection through horizontal wells exhibits the highest oil production (2,786,540.8 stb) compared to vertical wells. However, gas injection through two vertical wells yields an additional 20% of oil production. Moreover, the simulation study indicates that the most effective well placement occurs at a depth of 36 ft below the gas-oil contact (GOC) and 26 ft above the water-oil contact (WOC), resulting in a maximum oil production of 2,920,763.5 stb compared to other scenarios.

Keywords: Oil rim reservoir, horizontal well, Water and gas injection, well placement

Number of pages: 53

Number of annexes: 2

Declaration

I declare that I have prepared the bachelor's thesis myself and that I have stated all the used information resources in the thesis.

In Olomouc, June 28, 2023

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Ali Salar Salim

Acknowledgment

I would like to extend my heartfelt gratitude to Palacky University Olomouc for providing me with the opportunity to pursue my BSc project and for the resources and facilities made available to me throughout my research. I am grateful for the academic environment and the learning opportunities that the university has offered me.

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List of abbreviations

GOC	Gas oil contact
WOC	Water oil contact
PV	Pore volume
EOR	Enhanced Oil Recovery
ESP	Electrical submersible pump
FOPT	Field oil production total
FGPT	Field gas production total
FWCT	Field water cut
FPR	Field reservoir pressure

1. Introduction

An oil-rim reservoir is defined as a reservoir that has an oil zone with a significant and active gas cap above it, and a large and active aquifer below it. The shape of the oil rim can be a doughnut or pancake, depending on the configuration of the gas cap and aquifer surrounding the oil zone, as shown in Figure 1. Evaluating and managing oil-rim reservoirs can be challenging and require complex computational analysis due to the varying dynamics of the gas cap and aquifer in the doughnut and pancake oil-rim configurations. Studies by John et al. (2019), Elharith et al. (2019), Fan et al. (2015), Lawal et al. (2010), and Silva and Dawe (2010) have all acknowledged the complexities associated with managing oil-rim reservoirs.

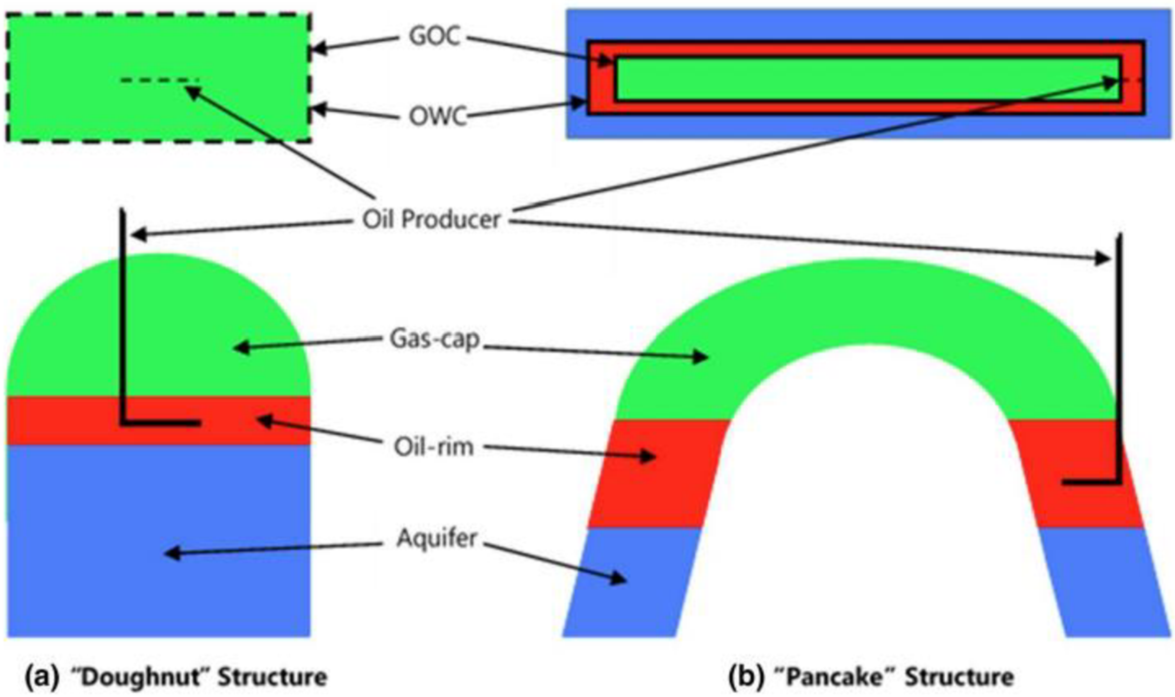

Figure 1 Showing the different shapes of oil-rim reservoirs in both plan view and cross-section (Lawal et al., 2010).

Due to the presence of an active gas cap and aquifer, exploiting oil rims can result in complicated production issues such as early gas and/or water breakthrough (Jaoua and Rafee 2019; John et al. 2019). Coning of gas and water is common in most oil-rim reservoir, causing negative impacts on well productivity and ultimate recovery. The continuous production of these undesired fluids increases operational costs and reduces the project's value. However, since coning rates are typically below economic thresholds, limiting oil production below gas and water coning rates has not been successful in practice (Balogun et al. 2015; Dilib et al. 2015; Lawal et al. 2010).

In terms of planning for development, there are always concerns about the most suitable development plan and type of well for a particular oil rim reservoir. Another issue is determining the optimal timing for initiating dedicated gas development by reducing the pressure on the remaining gas cap after the oil has been extracted up to a certain technological and economic threshold. Since both oil and gas are potential sources of revenue, developers often have extensive debates about the best approach to development at an early stage. They may consider options such as developing oil first and gas later, developing only the gas and ignoring the oil, developing both oil and gas at the same time but intermittently producing gas, or developing and producing both oil and gas concurrently. The justifications and opposing views for these choices are wide-ranging and may differ depending on the particular situation. This highlights the importance of enhancing the existing knowledge on this matter to make more informed decisions (Obidike et al. 2019a, b, Thomas and Bratvold, 2015).

The main mechanisms that drive oil rim reservoirs are gas cap expansion, solution gas expansion, and viscous withdrawal (Figure 2). Therefore, it is important to establish the equivalence of these mechanisms in order to maintain the stability of the oil rim structure. The reinjection of produced gas has been used to control pressure drops in the well and other parts of the reservoir, and this equivalence is greatly influenced by factors such as the strength of the aquifer, the location and distance of the proposed oil layer, and the well perforation. As a result, establishing this equivalency has helped to stabilize the oil and prevent its mobilization (Razmjoo et al., 2017). Despite the difficulties associated with oil rim reservoirs and their unprofitable economic conditions, there has been limited research into recovery techniques for these reservoirs. The primary aim of this project is to use the ECLIPSE simulator to assess various production/injection scenarios under different conditions and determine the optimal scenario.

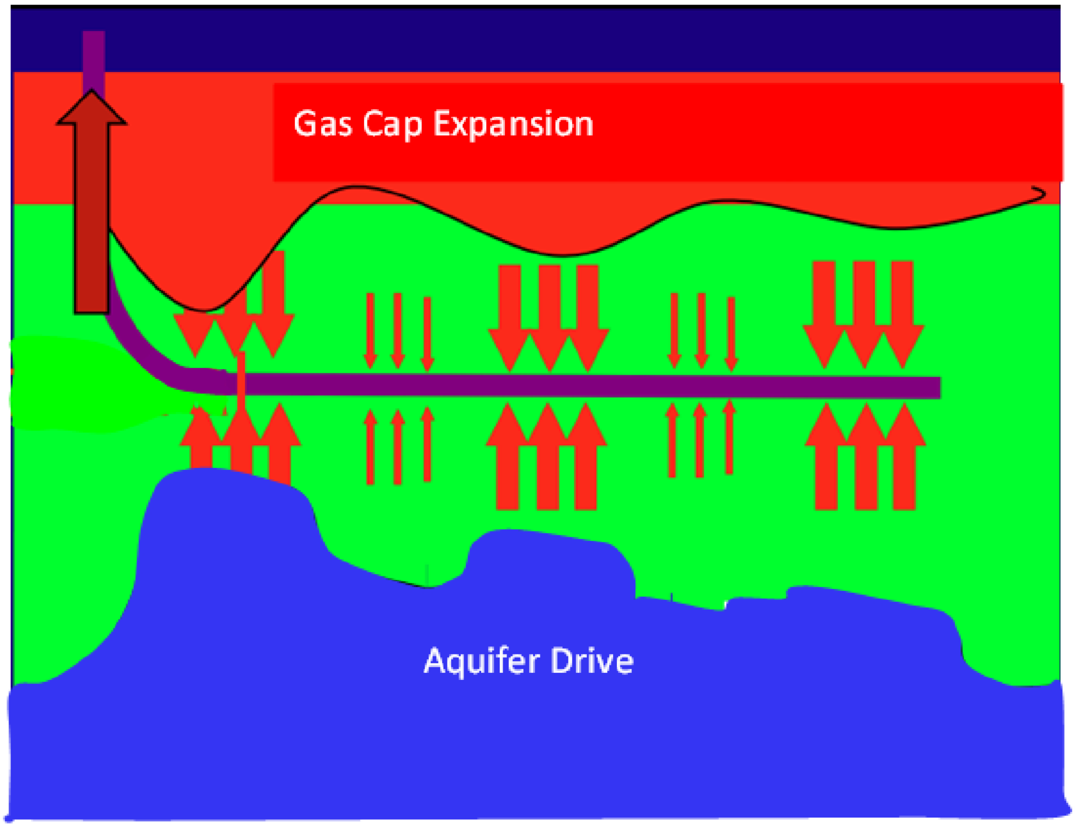

Figure 2 Oil rim reservoir force-balanced mechanisms.

1.1. Problem statement

Extracting oil from thin layers is always considered a costly venture, and it is a contentious issue among oil companies that plan to invest in it. Thin oil rim reservoirs, which are characterized by a thin oil column, pose additional challenges in terms of field development and oil production. Optimizing oil recovery in limited oil rims is also difficult due to the stabilization of the underlying water and overlying gas. The primary objective of field production is to ensure that the entire reserve is extracted, and the desired oil recovery level is achieved at minimum cost. However, meeting this requirement is impossible in a thin oil rim reservoir with a significant gas cap and a strong aquifer. Therefore, it is crucial to recover as much reserve oil as possible before the coning effect occurs for a productive project in this reservoir.

The recovery process of oil rim reservoirs is influenced by various subsurface factors such as oil column size, gas cap volumes/size, permeability, aquifer-strength, and oil viscosity.

Additionally, other factors like reservoir geometry, degree of heterogeneity, and magnitude of bed dip can also have a significant impact. Since these factors are inherent and cannot be changed, the focus has shifted to optimizing operational factors to minimize coning and maximize oil production. The primary operational factors include well trajectory, production rates, and optimizing well placement based on the gas cap sizes and aquifer strength.

1.2. Aim of project

The main aim of this project is to simulate different case scenarios of production from a thin oil rim to obtain:

1. To understand the nature of a thin oil rim
2. To enhance oil production in thin oil rims considering different scenarios of improved oil recovery methods.
3. To simulate a thin oil rim reservoir and production mechanism
4. To identify the most effective improved oil recovery methods.

2. Literature review

2.1. Oil rim reservoir

Thin oil column reservoirs are typically found with water underneath and/or gas on top. The thickness of the oil column in these reservoirs usually ranges from less than 30 feet to 90 feet. In thin oil rim reservoirs, where the oil column is limited in thickness regardless of the rock type and properties, the hydrocarbon column is mostly located in the capillary transition zone (Masoudi et al., 2011). The capillary transition zone has a high saturation of water, along with an underlying aquifer and an overlying gas cap, leading to complex flow dynamics in these reservoirs.

Extracting oil from oil rim reservoirs has always been challenging due to the thinly spread oil resources and the complexities of production mechanisms. When a vertical well is drilled through such a reservoir, the contact length between the well and the oil column is small. This limited contact area, combined with the significant pressure drop associated with flow into a vertical well, makes these wells highly susceptible to coning. The productivity of vertical wells in thin oil column reservoirs is often marginal or uneconomical, especially when the mobility ratio is unfavorable and the permeability is low to moderate (Olabode et al., 2018).

The same issue can arise even if the thin oil reservoir is surrounded by impermeable rock instead of gas or water. In such cases, although a vertical well doesn't encounter coning, its productivity can still be insufficient for economic viability. On the other hand, horizontal wells can significantly increase reservoir contact and greatly improve productivity, sometimes reaching up to five times that of vertical wells in oil rim reservoirs. Oil companies face numerous technical and commercial challenges in developing oil rim reservoirs and extracting resources from the capillary transition zone, which reduces the attractiveness of such field development from both technical and economic perspectives. These challenges include concerns about water/gas coning and breakthrough, dispersed resources, complex production methods, and drive mechanisms (Iyare et al., 2012).

2.2. Challenges of production from thin oil Rim

Oil companies are aware of multiple technical and commercial obstacles when developing oil rim reservoirs and extracting resources from the capillary transition zone. These challenges make such field development less attractive from both technical and economic perspectives. In order to produce oil from thin oil rims, it's necessary to identify and understand these challenges so that effective solutions can be developed. This section will focus on highlighting these challenges, which can be divided into two categories: technical challenges, which are linked to reservoir characteristics and production mechanisms, and business challenges, which relate to the operator company's decisions and costs.

2.2.1. Technical Challenges

Oil rim reservoirs present several technical challenges that need to be addressed during development and production. These challenges arise due to the unique characteristics of oil rim reservoirs, including their limited thickness and the presence of a capillary transition zone (Jaoua and Rafee, 2019).

One of the primary technical challenges is the thinness of the oil column. Oil rim reservoirs have a restricted vertical extent, resulting in thinly spread oil resources. This poses difficulties in reservoir characterization, as it becomes crucial to accurately map and understand the reservoir's properties, such as permeability, porosity, and fluid saturations, within a limited vertical space. The capillary transition zone within oil rim reservoirs presents another significant challenge (Iyare et al., 2012). This zone occurs due to capillary pressure generated when immiscible fluids, such as oil and water, mix. The hydrocarbon column in oil rim reservoirs is mainly situated within this capillary transition zone, regardless of the rock type or properties. Understanding the complex fluid behavior and flow dynamics within this zone is essential for optimizing production and recovery strategies. The presence of water saturation, along with an underlying aquifer and an overlying gas cap, further complicates the flow dynamics within oil rim reservoirs. The high saturation of water in the capillary transition zone, in particular, introduces challenges in managing water/gas coning and breakthrough (Figure 3).

Coning occurs when the lower density fluids override the oil, reducing oil production and recovery rates (Taha and Amani, 2019). Additionally, the heterogeneity of reservoir properties poses technical challenges. Variations in rock types, permeability, and porosity within the limited vertical thickness of oil rim reservoirs can lead to spatial variations in fluid flow. Optimizing production and reservoir management strategies requires a detailed understanding of these heterogeneities and their impact on fluid flow behavior.

Accurate reservoir characterization, development of appropriate production mechanisms, and addressing issues related to coning, breakthrough, and heterogeneity are crucial for successfully developing and producing from oil rim reservoirs (Omeke et al., 2010). These technical challenges require innovative approaches, advanced modeling techniques, and robust production strategies to overcome the inherent complexities and maximize the recovery potential of these reservoirs.

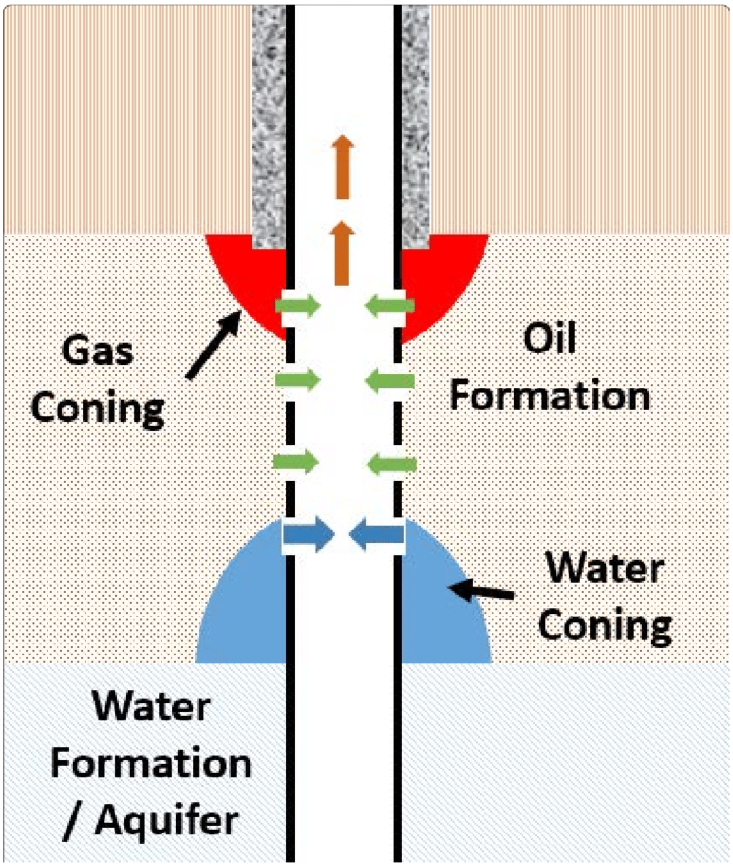

Figure 3 Show the mechanism of water and gas coning in oil rim reservoir (Taha and Amani, 2019).

2.2.2. Business challenges

In addition to the technical challenges, oil rim reservoirs also pose certain business challenges that need to be considered during their development and production. These challenges are related to the decision-making processes and economic aspects of operating in such reservoirs. One of the primary business challenges is the economic viability of developing oil rim reservoirs (Morshedi and Ameri, 2019). The thinly spread oil resources, limited thickness of the reservoir, and complex flow dynamics can impact the overall profitability of the project. The costs associated with drilling and production operations, along with the potential low productivity of vertical wells, need to be carefully evaluated to determine the economic feasibility of extracting oil from these reservoirs. Furthermore, the dispersed nature of oil rim reservoirs and the uncertainties associated with reservoir characteristics and production mechanisms can create additional challenges for oil companies. The uncertainty surrounding the reservoir's behavior and the need for accurate reservoir characterization can increase the financial risks involved in developing and producing from oil rim reservoirs (Abdulraheem et al., 2017).

Another business challenge is the need for specialized expertise and technology. Developing and operating oil rim reservoirs requires specific knowledge and skills due to the unique challenges associated with these reservoirs. Oil companies must have access to advanced technology, reservoir modeling tools, and production techniques that can effectively address the complexities of oil rim reservoirs. Additionally, the market conditions and oil prices play a significant role in determining the commercial viability of oil rim reservoirs (Chauhan et al., 2015). Fluctuating oil prices can impact the profitability and economic attractiveness of developing these reservoirs. Oil companies need to consider market trends, price forecasts, and long-term investment plans to make informed decisions regarding the development and production of oil rim reservoirs. Overall, the business challenges of oil rim reservoirs revolve around the economic viability, financial risks, specialized expertise requirements, and market conditions. Successfully navigating these challenges requires careful economic analysis, risk management strategies, and the adoption of appropriate technologies and practices to ensure the profitability and long-term sustainability of oil rim reservoir projects (Tardieu and Omnes, 2014).

2.3. Technique for enhancing oil production in oil rim reservoir

There are several techniques commonly employed for enhancing oil production in oil rim reservoirs. These techniques aim to improve sweep efficiency, increase the contact between the reservoir and the producing wells, and maximize oil recovery (Al-Enezi et al., 2013; Elkatatny et al., 2015; Zoveidavianpoor et al., 2017). Some of the key techniques include:

1. Selective Completion: Selective completion involves using intelligent well completion techniques to target specific intervals within the oil rim reservoir. This technique allows operators to control and optimize production from different layers or zones, effectively managing the fluid flow and enhancing oil recovery. By selectively completing intervals with higher oil saturation and avoiding zones with water or gas, selective completion can improve overall sweep efficiency.

2. Advanced Reservoir Management: Effective reservoir management strategies play a vital role in enhancing oil production in oil rim reservoirs. This includes monitoring reservoir performance, implementing pressure maintenance techniques, and optimizing production and injection rates. Advanced reservoir monitoring technologies such as surveillance wells, downhole sensors, and reservoir simulation models help operators gain better insights into reservoir behavior, optimize well placement, and adjust operating parameters for improved oil recovery.

3. Artificial Lift Systems: In some cases, artificial lift systems are employed to enhance oil production in oil rim reservoirs. These systems, such as electric submersible pumps (ESPs), rod pumps, or gas lift systems, help overcome the natural pressure decline in the reservoir and lift the oil to the surface. By maintaining reservoir pressure and improving the flow of oil, artificial lift systems can significantly increase production rates and overall recovery.

4. Enhanced Oil Recovery (EOR) Techniques: EOR techniques are employed to further enhance oil production in oil rim reservoirs. Waterflooding, is a common EOR technique where water is injected into the reservoir to displace and push oil towards production wells. Additionally, gas injection (such as carbon dioxide or nitrogen) or chemical

injection (such as polymer or surfactant) can be employed to improve oil displacement and recovery efficiency.

5. Integrated Field Development: Integrated field development involves comprehensive planning and coordination of drilling, production, and reservoir management activities. It takes into account the specific characteristics of the oil rim reservoir and the surrounding formations to optimize well placement, injection patterns, and production strategies. Integrated field development considers factors such as reservoir heterogeneity, fluid behavior, and connectivity, ensuring an integrated approach for maximizing oil recovery.

These techniques are often implemented in combination or tailored to the specific characteristics of the oil rim reservoir to achieve optimal results. Successful application of these techniques requires detailed reservoir characterization, data analysis, modeling, and ongoing monitoring and optimization to adapt to changing reservoir conditions and improve oil production over time.

2.4. Factors effect on the performance of oil rim reservoir

Several reservoir factors significantly influence the performance of oil rim reservoirs. These factors impact fluid flow dynamics, sweep efficiency, and overall oil recovery. Understanding and managing these reservoir factors are crucial for optimizing production and maximizing hydrocarbon extraction. Some key reservoir factors that affect the performance of oil rim reservoirs are reservoir heterogeneity, oil Saturation and thickness, aquifer support and bottom water, reservoir pressure and drive mechanisms and reservoir compartmentalization (Al-Sumaiti et al., 2016).

Oil rim reservoirs often exhibit significant heterogeneity in terms of rock properties, fluid distribution, and reservoir connectivity. Variations in permeability, porosity, and fluid saturations within the reservoir can lead to uneven fluid flow and inefficient sweep efficiency. Characterizing and understanding the reservoir's heterogeneity through techniques such as well logs, core analysis, and reservoir modeling is essential for effective reservoir management and production optimization (Olatunji et al., 2019).In addition, the oil saturation and thickness of the oil rim directly influence the recoverable oil volumes and production rates. Higher oil saturation and thicker oil rims generally result in higher oil recovery factors. Reservoir characterization techniques, including core analysis and well testing, provide valuable insights into the distribution and saturation of oil within the reservoir. Furthermore, the presence of an aquifer or bottom water zone can significantly impact oil rim reservoir performance. Aquifer support can maintain reservoir pressure and provide energy for oil displacement, thereby enhancing oil recovery (Soltanian and Ghotbi, 2019). On the other hand, the influx of bottom water can lead to early water breakthrough, reduced sweep efficiency, and decreased oil production rates. Understanding the dynamics of aquifer support and managing bottom water coning is crucial for optimizing production strategies. Moreover, reservoir pressure and the nature of the drive mechanisms have a direct impact on oil production rates and ultimate recovery. In oil rim reservoirs, the primary drive mechanisms may include solution gas drive, aquifer support, or gas cap expansion. Monitoring and managing reservoir pressure through pressure maintenance techniques, such as water injection or gas injection, can help sustain reservoir energy and improve oil recovery. Finally, oil rim reservoirs may exhibit compartmentalization, where the reservoir is divided into isolated compartments or layers. These compartments can have different fluid properties, connectivity, and pressure regimes. Proper characterization and understanding of reservoir compartmentalization are essential for optimizing well placement, selecting appropriate completion techniques, and designing effective production strategies (Fadaei, 2014).

Understanding and managing these reservoir factors requires a comprehensive approach that combines geological, geophysical, and reservoir engineering techniques. Detailed reservoir characterization, data analysis, and reservoir modeling are essential for optimizing production strategies, implementing enhanced oil recovery techniques, and maximizing oil recovery from oil rim reservoirs.

2.5. Production strategies in oil rim reservoir

Efficient production strategies are crucial to maximize oil recovery from thin oil reservoir. To ensure successful exploitation of oil rim reservoirs, it is necessary to combine technical expertise with a business-oriented and committed approach (Masoudi et al., 2011). Figure 4 illustrates a techno-commercial model that encompasses essential elements and a step-by-step evaluation process to generate a comprehensive plan for field development and management of the oil rim. The foundation of this development pyramid lies in obtaining a reliable reservoir description and understanding the flow dynamics. Subsequently, early production and business commitments, along with contractual agreements, need to be considered to determine the most suitable production and depletion strategies. Once the reservoir potential and production/depletion strategy have been identified, the design and philosophy of well completion and the reservoir management plan (RMP) can be finalized (Elharith et al., 2019).

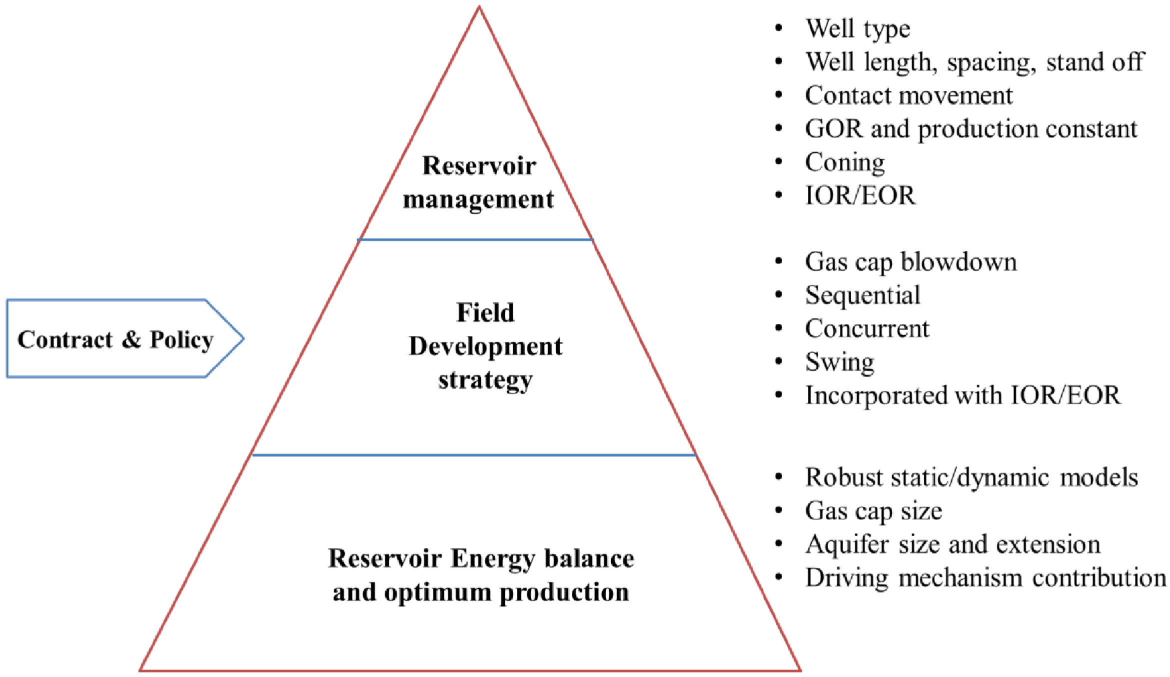

Figure 4 Factors that contribute to the effective management of oil rim reservoirs (Masoudi et al., 2011)

There are varying viewpoints in the literature regarding the optimal strategies for production and depletion in oil rim reservoirs. Olatunji et al. (2019) conducted a study showing that the gas cap to oil volume ratio (M factor) and the thickness of the oil rim can serve as initial criteria for determining the appropriate production and depletion approach.

According to Olatunji et al. (2019), if the thickness of the oil rim is above 30 ft and the M factor is less than 2, a sequential development strategy, where oil is produced first followed by gas, is recommended. However, in cases where the M factor is above 2 and the thickness exceeds 30 ft, a concurrent production strategy for both oil and gas, with controlled rates, can be pursued. Another viable option is the swing method, which involves cyclically shifting between oil and gas production to maintain pressure balance. This approach is particularly suitable for reservoirs with significant gas caps and is considered preferable.

3. Methodology

3.1.Black oil simulator (ECLIPSE 100)

The black oil simulator, Eclipse 100, is a widely used reservoir simulation software package developed by Schlumberger. It is designed specifically for modeling and simulating the behavior of oil reservoirs, particularly those with a substantial amount of dissolved gas and a complex phase behavior. Eclipse 100 allows engineers and geoscientists to analyze and optimize the production of oil and gas fields by predicting fluid flow and reservoir performance over time (Schlumberger Eclipse manual, 2010). The key features of Eclipse 100 are:

1. Fluid Modeling: Eclipse 100 employs a black oil model, which is a simplified representation of fluid behavior in reservoirs. It assumes that oil consists of three main components: live oil, dissolved gas, and water. This model accounts for the thermodynamic interactions among these components and captures phase behavior, including the formation and movement of oil, gas, and water fronts.
2. Grid-based Reservoir Representation: The reservoir is discretized into a grid, dividing the subsurface domain into small cells. Each cell represents a portion of the reservoir, and properties such as permeability, porosity, and initial fluid saturation are assigned to the cells. The simulator can handle structured, unstructured, and corner-point grids, allowing for a flexible representation of complex reservoir geometries.
3. Numerical Solution Methods: Eclipse 100 utilizes numerical techniques to solve the equations governing fluid flow through the reservoir. It employs finite difference methods to discretize the equations and solve them iteratively. Several advanced solution schemes are available to handle various scenarios, including fully implicit, IMPES (implicit pressure-explicit saturation), and other hybrid schemes.
4. Well Modeling: The simulator provides comprehensive capabilities for modeling production and injection wells. Engineers can define well locations, trajectories, completion details, and operational parameters such as flow rates, pressure constraints, and wellbore storage effects. The well models can incorporate various wellbore configurations, including vertical, deviated, multilateral, and completions with hydraulic fractures.

5. Reservoir Management and Optimization: Eclipse 100 facilitates reservoir management by allowing engineers to analyze different development strategies and optimize field performance. It enables the evaluation of enhanced oil recovery (EOR) methods, water and gas injection scenarios, and various well control strategies to maximize oil recovery and reservoir economics. The software also includes tools for history matching, uncertainty analysis, and production forecasting.
6. Visualization and Analysis: The simulator offers visualization and analysis tools to interpret simulation results. Engineers can generate graphical outputs, such as pressure and saturation maps, streamline plots, production profiles, and cross-sectional views of the reservoir. These visualizations help in understanding fluid behavior, identifying flow patterns, and making informed decisions regarding reservoir management.

3.2. Model description

To create a hypothetical oil rim reservoir, the ECLIPSE simulator is employed for static modeling, utilizing pertinent data. The data for the model is derived from the SPE 9^{th} comparative study. The model is constructed using a grid with dimensions of 24 x 25 x 15 in the i, j, and k directions. The grid is symmetrical and has equal width and length, each grid measuring 300 feet. The model has a thickness of 427 feet, and the cell height ranges from 60 feet to 5 feet. Figure (5) shows the oil rim reservoir model in 3D viewer.

In order to make the study more realistic and applicable, various porosities and permeabilities are assigned to individual reservoir grids. The porosity values vary from 8.7% to 17%, while the permeability values range from 0 to 1000 mD. The properties of reservoir model are summarized in table 1. Furthermore, relative permeabilities and capillary pressure for oil, water and gas were assigned to the model, as shown in figures 6, 7, 8 and 9. It's worth to mention that relative permeability data and capillary pressure are critical to this project as it focuses on the flow of each phase and how it influences oil recovery. Moreover, fluid data were taken from SPE 9th comparative study. Reservoir fluid characterization is shown in figure 10a, b, c and d.

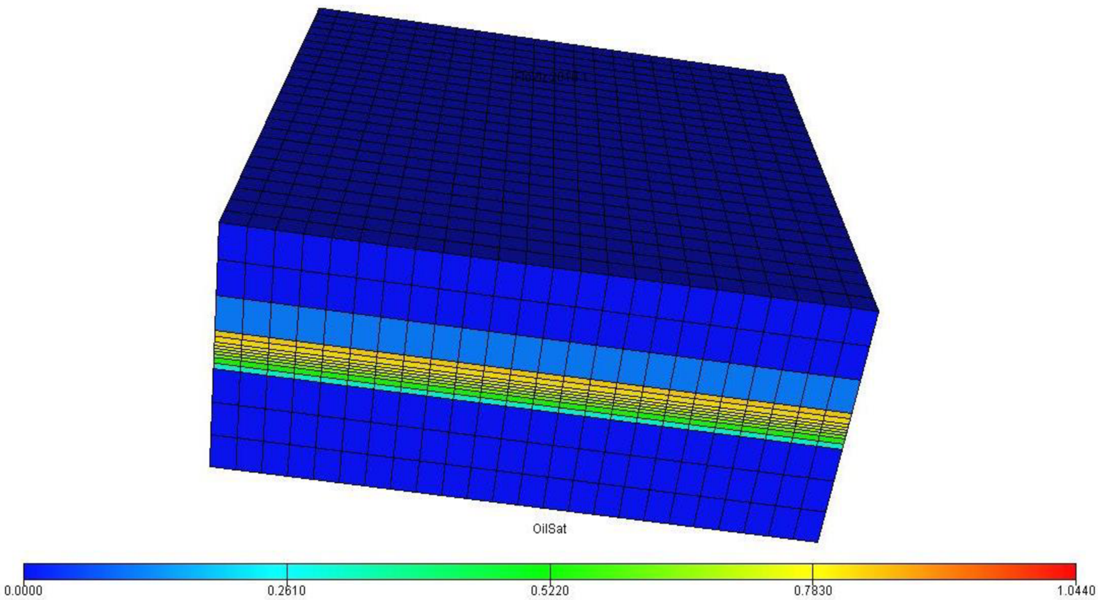

Figure 5 shows the oil rim reservoir model in 3D viewer

Table 1 Oil rim reservoir model parameters

Properties	**Values**
Grid Dimension in I, J and K direction	24x25x15
Hydrocarbon pore volume	482621738 rbbl
Datum (subsurface)	7213.5 ft
Oil rim thickness	67 ft
Water/Oil contact	7247 ft
Gas/Oil contact	7180 ft
Initial pressure at contact	4000 psia
Oil, water and gas gravity	35 API, 1.0096 and 0.75
PV compressibility	4.0×10^{-6} psi $^{-1}$

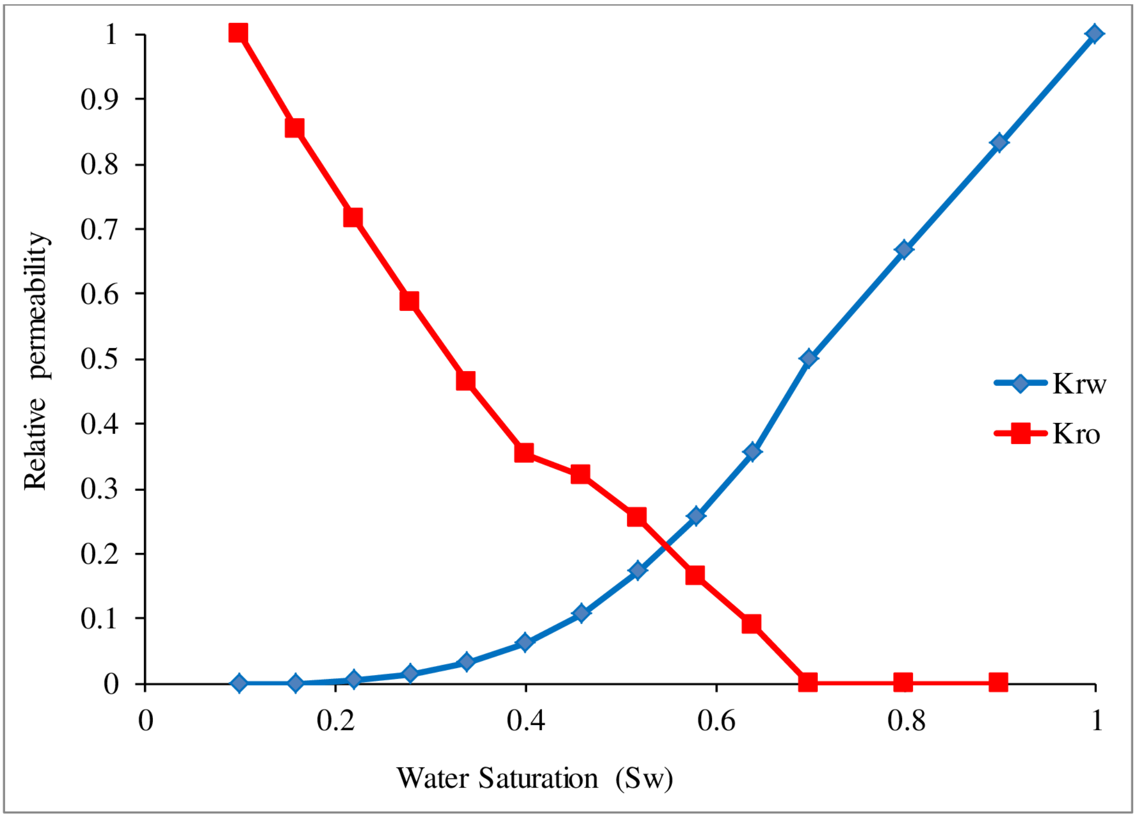

Figure 6 Shows oil and water relative permeability curves.

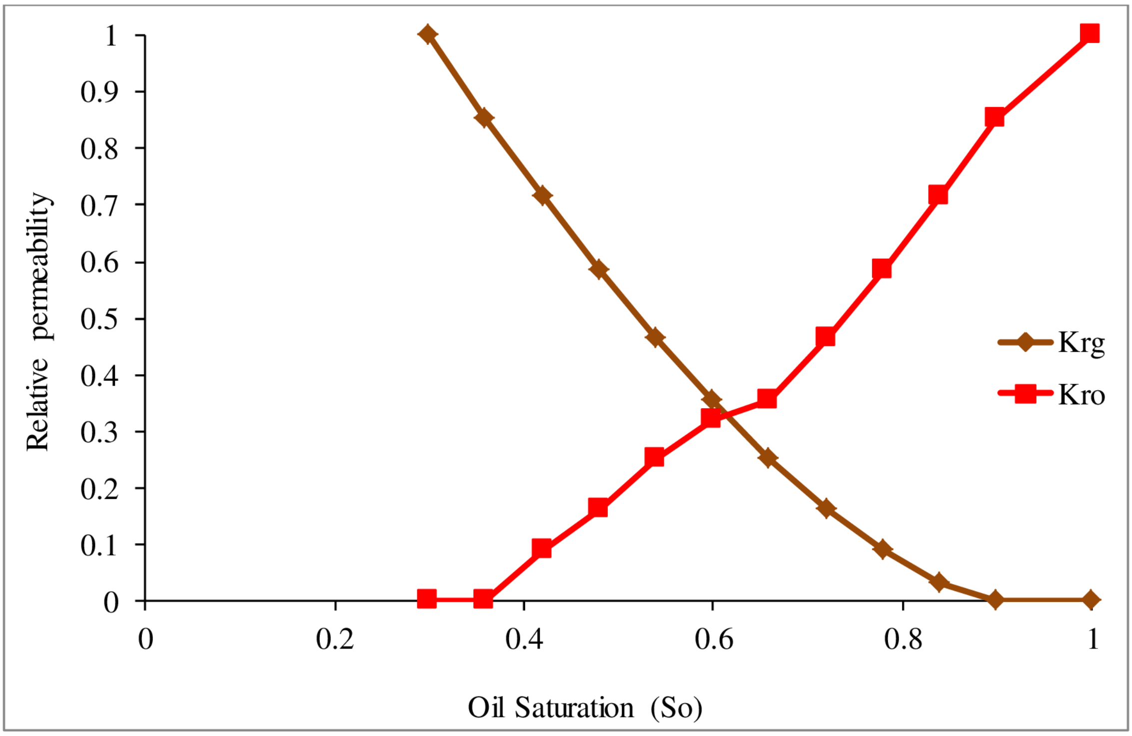

Figure 7 Shows Oil and gas relative permeability curves

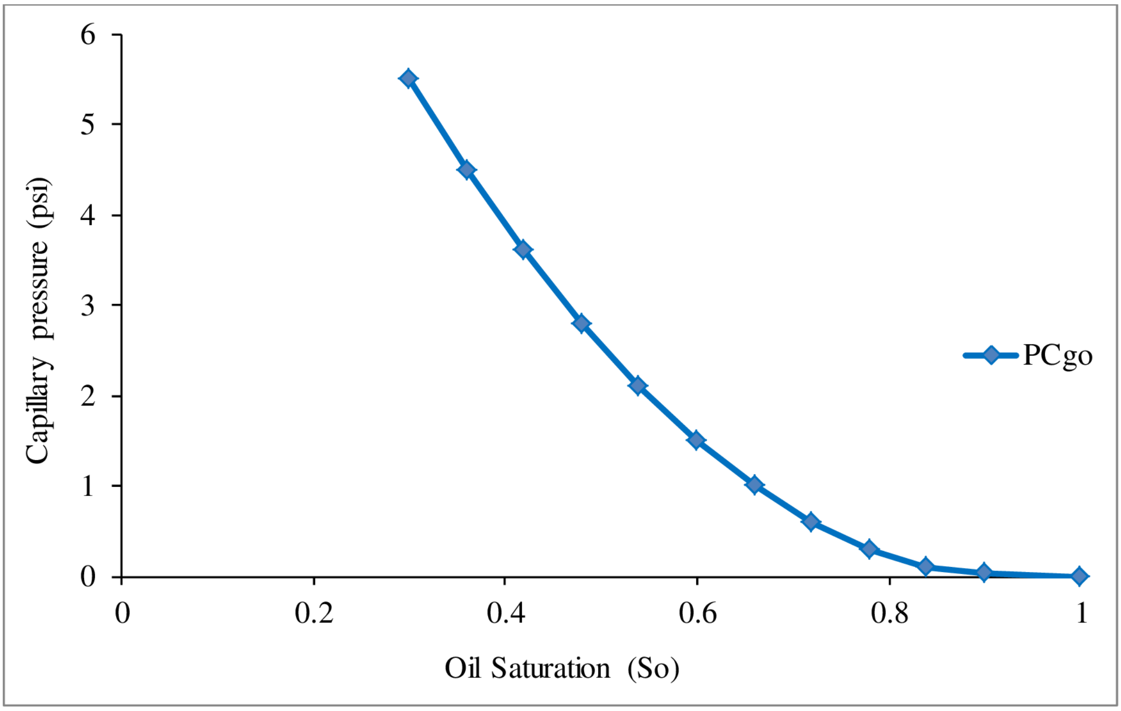

Figure 8 Shows Oil-gas capillary pressure curve.

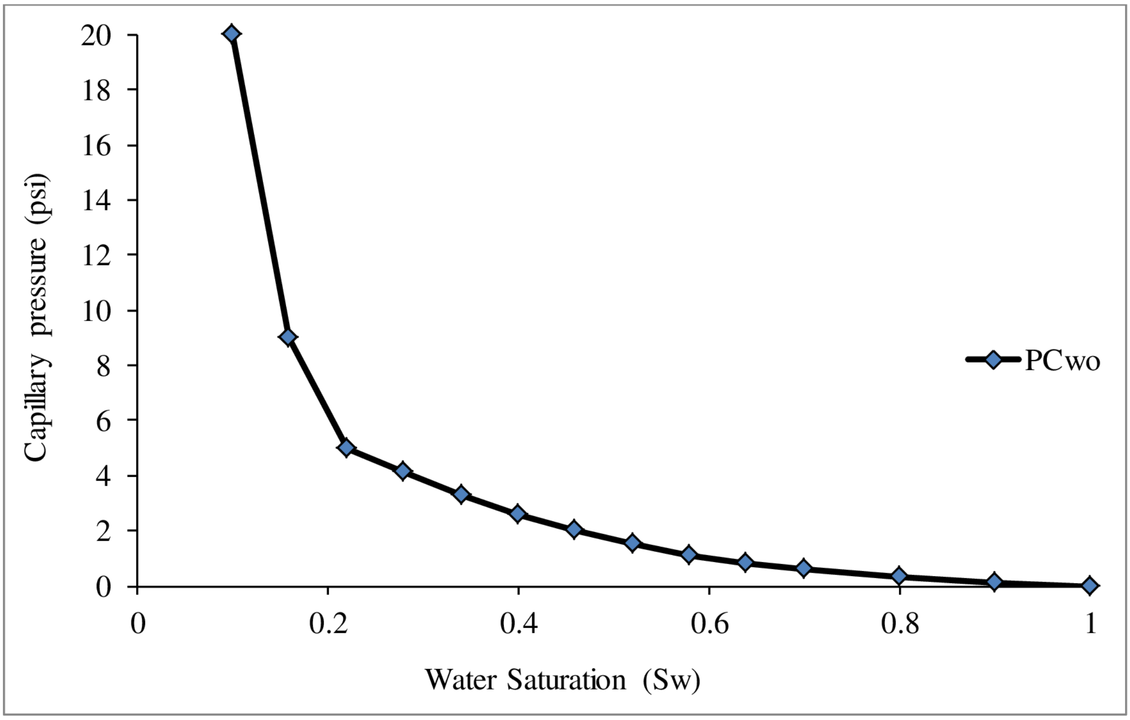

Figure 9 Shows water-oil capillary pressure **curve.**

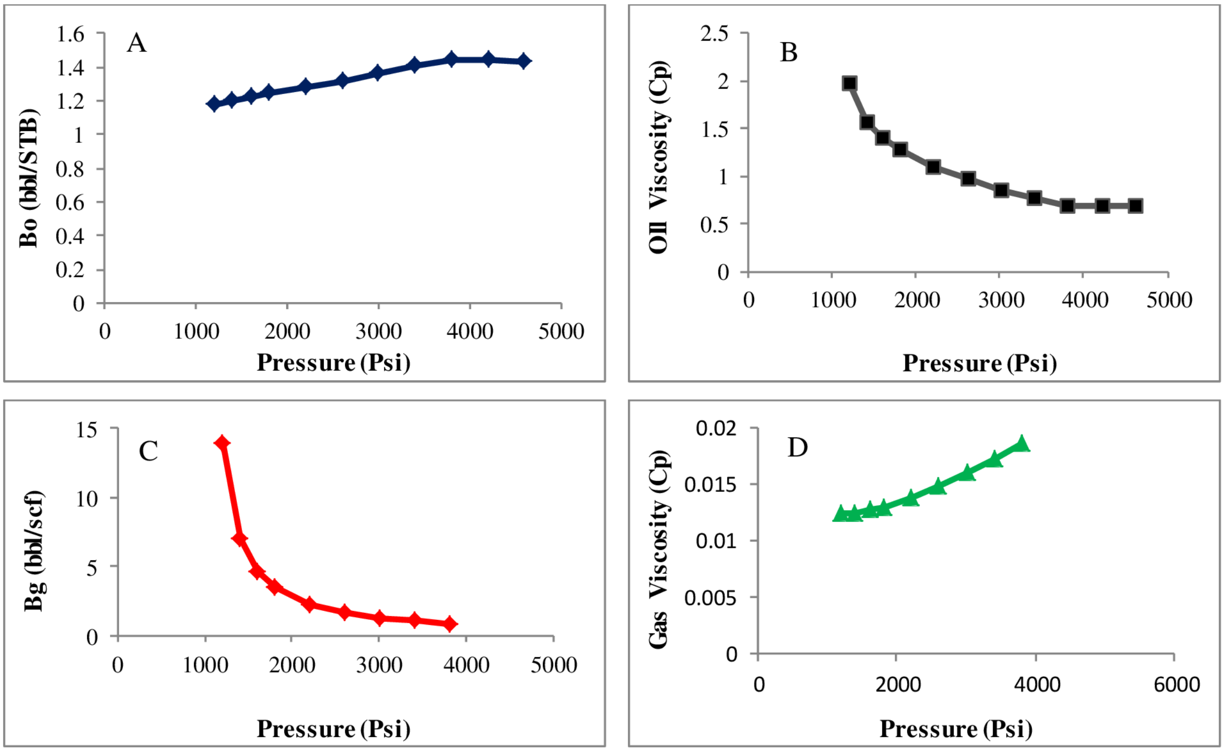

Figure 10 Show reservoir fluid characterization A) oil formation volume factor B) oil viscosity C) gas formation volume factor D) gas viscosity vs. pressure for the base case model.

3.3. Base case Model

After initializing the oil rim reservoir model with all relevant data, dynamic modeling was used to simulate different scenarios based on the project goal. The first scenario, designated as the base case in this study, assumed natural depletion production. The base case included two producers (prod, prod2), both of which were horizontal wells (Figure 11). The first producer (prod) was completed in layer 7 from cell 12 to 18 in the x-direction, while the second well (prod2) was completed in layer 7 from cell 9 to 15 in the x-direction. The wells were controlled by oil rate, and the simulation was conducted for 5 years

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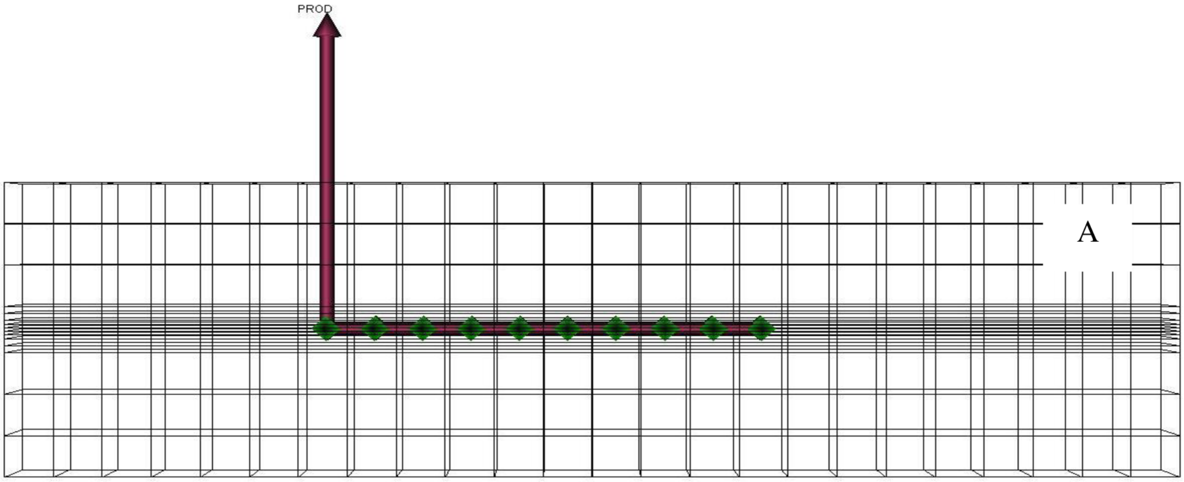

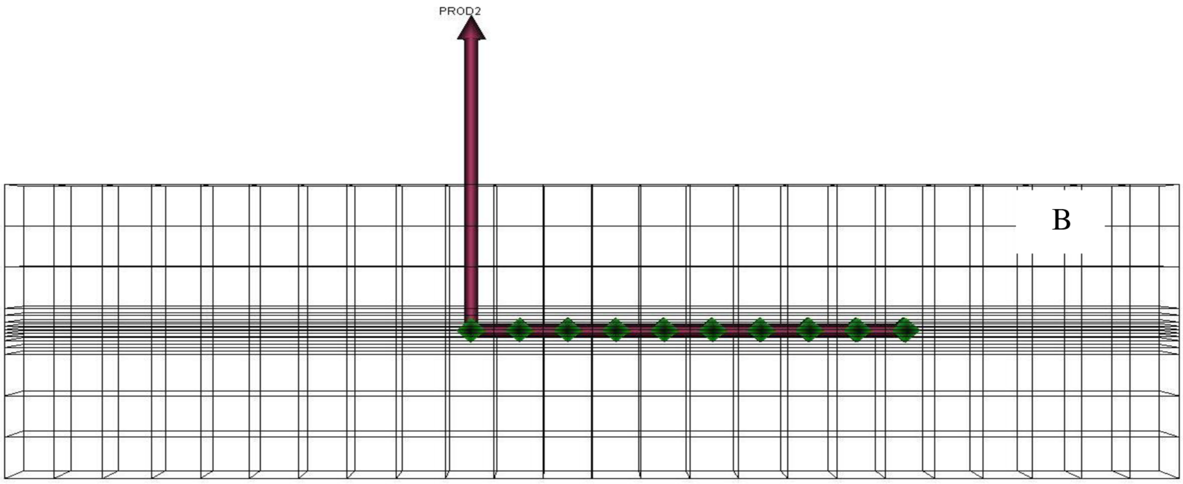

Figure 11 Show the location of horizontal wells in the base case model

3.4. Simulation study

To maximize oil production from an oil rim reservoir, various factors such as the horizontal well length, well type, injection fluid, and the placement of the well with respect to the WOC or GOC are taken into consideration. To achieve this goal, different scenarios were set up, as follows:

- **In the first case**: the toe to heel length of the horizontal well was considered as a key parameter affecting oil production. To investigate this factor, three different scenarios were simulated with lengths of 2100 ft, 2400 ft, and 2700 ft, and the results were compared to the base case, which had a length of 1800 ft (Table 2).

Table 2 Show the simulation scenarios to study the effect of toe to heel length on oil production.

Case Name	**Description**
Base Case	Toe to hell length is 1800 ft
HW_Oil_Producers_2100ft	Toe to hell length is 2100 ft
HW_Oil_Producers_2400ft	Toe to hell length is 2400 ft
HW_Oil_Producers_2700ft	Toe to hell length is 2700 ft

- **In the second and third cases**: the impact of injection water and gas on oil production in the oil rim reservoir was examined using different well types (Table 3 and 4).

Table 3 Show the simulation scenarios to study the effect of water injection on oil production.

Case Name	**Description**
Base Case	2 horizontal well oil producers
2HW_Producers+1VW_WINJ	2 horizontal well oil producers with 1 vertical water injector
2HW_Producers+2VW_WINJ	2 horizontal well oil producers with 2 vertical water injectors
2HW_Producers+1HW_WINJ	2 horizontal well oil producers with 1 horizontal water injectors

Table 4 Show the simulation scenarios to study the effect of gas injection on oil production.

Case Name	**Description**
Base Case	2 horizontal well oil producers
2HW_Producer+1VW_GINJ	2 horizontal well oil producers with 1 vertical gas injector
2HW_Producer+2VW_GINJ	2 horizontal well oil producers with 2 vertical gas injectors
2HW_Producer+1HW_GINJ	2 horizontal well oil producers with 1 horizontal gas injector

- **In the fourth case**: the distance between the horizontal well completion and the WOC and GOC was studied (Table 5).

Table 5 Show the simulation scenarios to study the effect of well placement with respect to WOC and GOC on oil production.

Case Name	Description
Base Case	26 ft below GOC and 36 ft above WOC
GOC_20ft_WOC_41ft	20 ft below GOC and 41 ft above WOC
GOC_31ft_WOC_31ft	31 ft below GOC and 31 ft above WOC
GOC_36ft_WOC_26ft	36 ft below GOC and 26 ft above WOC

In all cases, cumulative oil production, gas production and water cut were recorded, and the results were analyzed and compared.

4. Results and discussions

4.1. Affect the length of horizontal well on oil production.

Drilling a longer horizontal wellbore results in a higher yield of oil production. This advantage is unique to the horizontal well, as opposed to the vertical well. However, drilling a horizontal wellbore is more expensive than drilling a vertical well, and therefore, for the horizontal well to be economically viable, the wellbore must be long enough. This means that optimizing the length of the horizontal wellbore is necessary in order to achieve greater economic efficiency.

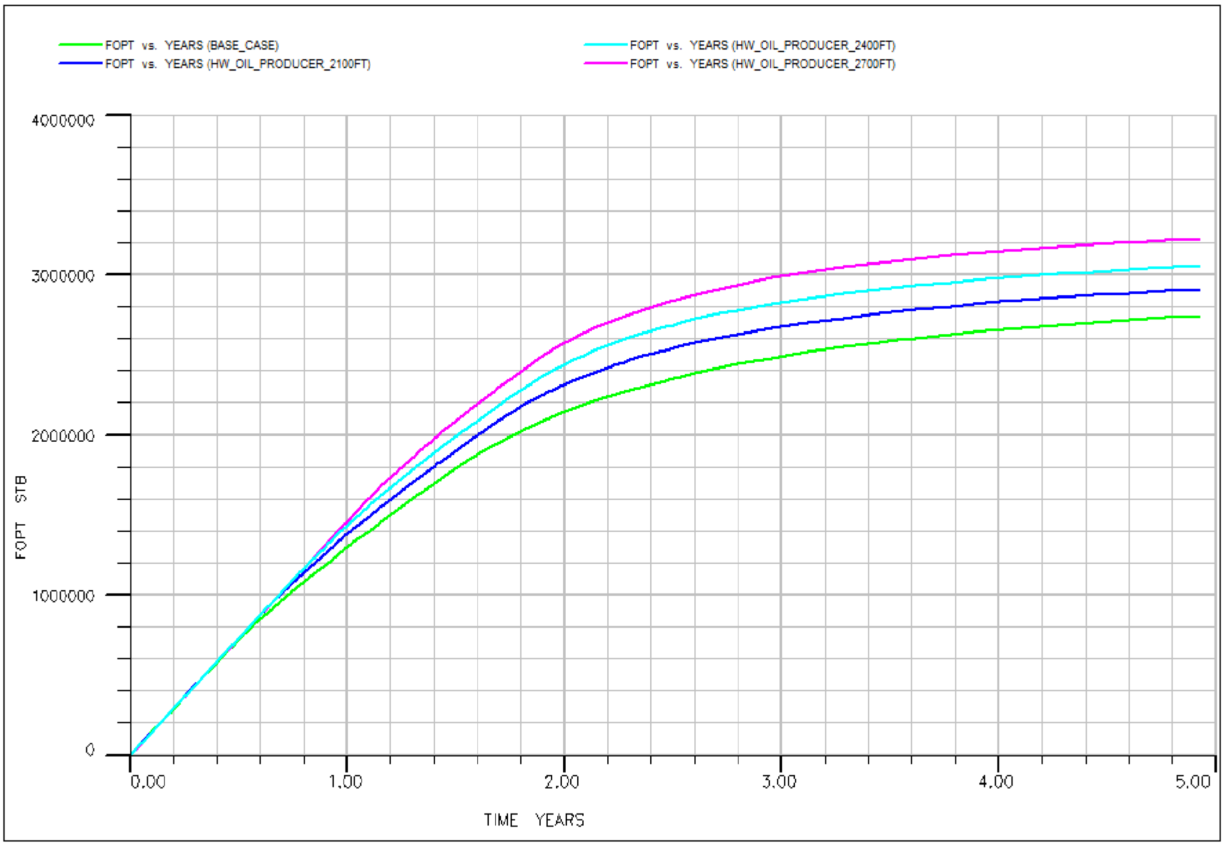

Figure 12 Cumulative oil production vs time for different horizontal well length.

Figure 12 illustrates that increasing the length of a horizontal well from the base case of 1800 ft to 2700 ft resulted in a 17.5% increase in oil production, from 2745440.5 STB to 3225610.8 STB. This is because a longer wellbore allows for a greater contact area with the reservoir, compared to the base case. Additionally, increasing oil production leads to expansion of the gas cap, resulting in increased gas production. Figure 13 demonstrates that a horizontal well with a length of 2700 ft produces 1.5x10^{11} scf of gas, while shorter well lengths result in decreased gas production.

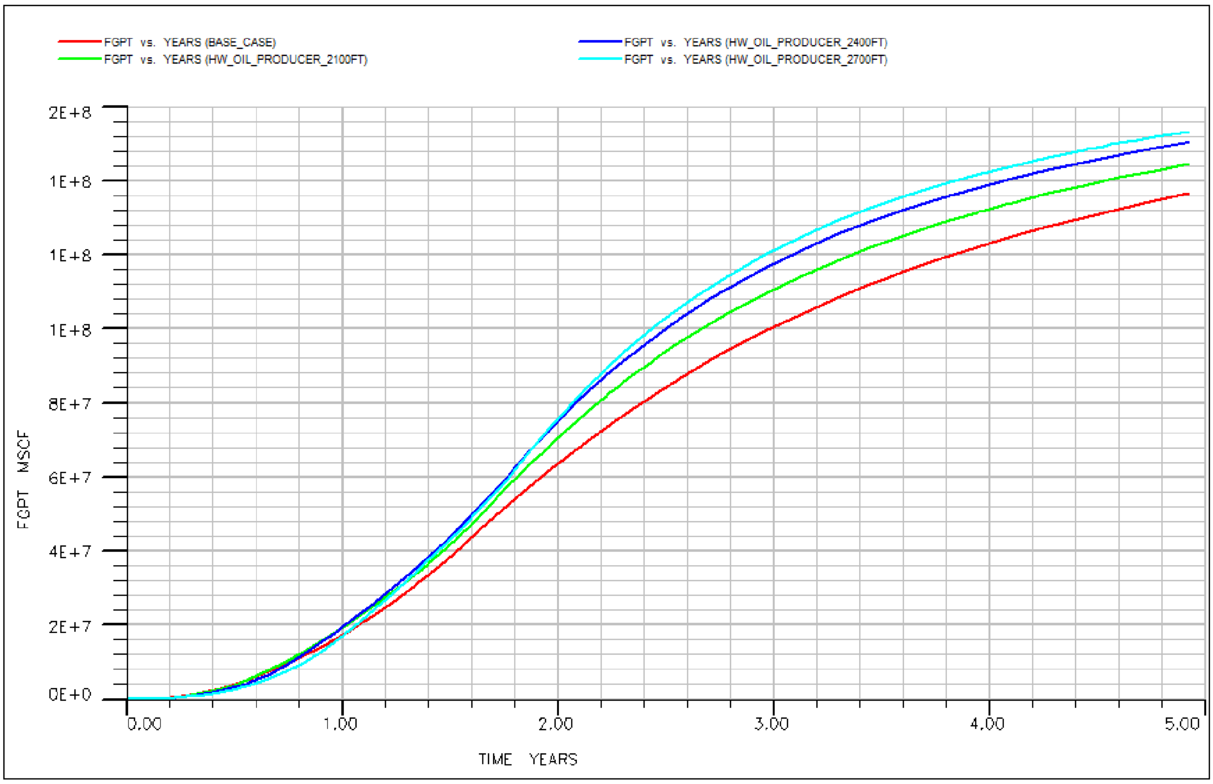

Figure 13 Cumulative gas production vs time for different horizontal well length

Figure 14 displays the relationship between water cut (FWCT) and time. It should be noted that because of completing the wells at the same distance above the WOC, the amount of produced water for all cases was nearly identical, at approximately 81%.

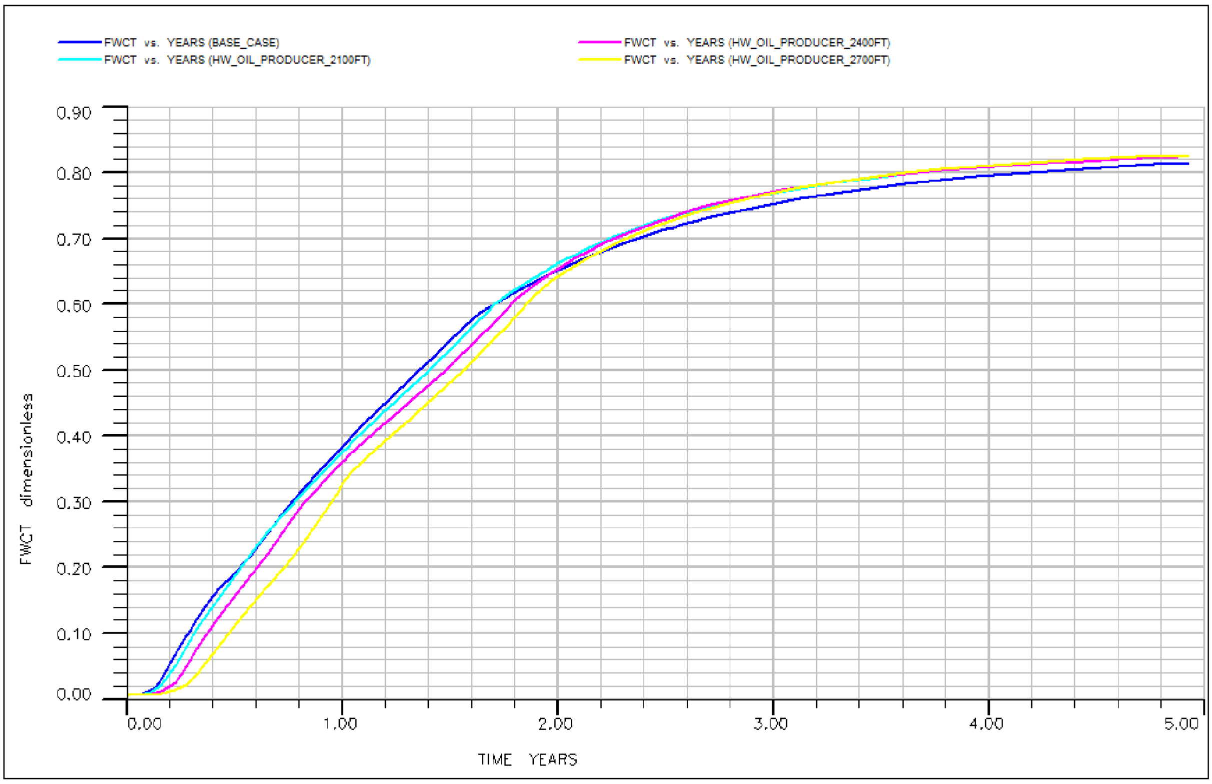

Figure 14 Field water cut vs time for horizontal well length.

4.2. Effect of water injection on oil production

In an oil rim reservoir, water injection can be particularly effective as it helps to maintain the gas cap and prevent its depletion. As the water is injected into the reservoir, it pushes the oil towards the production wells, while the gas cap above the oil remains intact. This ensures that the pressure in the gas cap is maintained, which helps to keep the oil production rate high.

The graph presented in Figure 15 shows the cumulative oil production over time for various water injection strategies. It is apparent from the graph that injecting water via horizontal wells yields the highest amount of oil production (2786540.8 stb) when compared to the other injection methods. This is due to the fact that horizontal wells can reach a larger area of the reservoir, which enhances oil recovery and postpones the occurrence of water breakthrough (Figure 16). In addition, it is worth mentioning that even though the total amount of gas produced in all the scenarios was similar, injecting water into the reservoir helps maintain the pressure in the gas cap. This, in turn, helps to maintain a high rate of oil production (Figure 17).

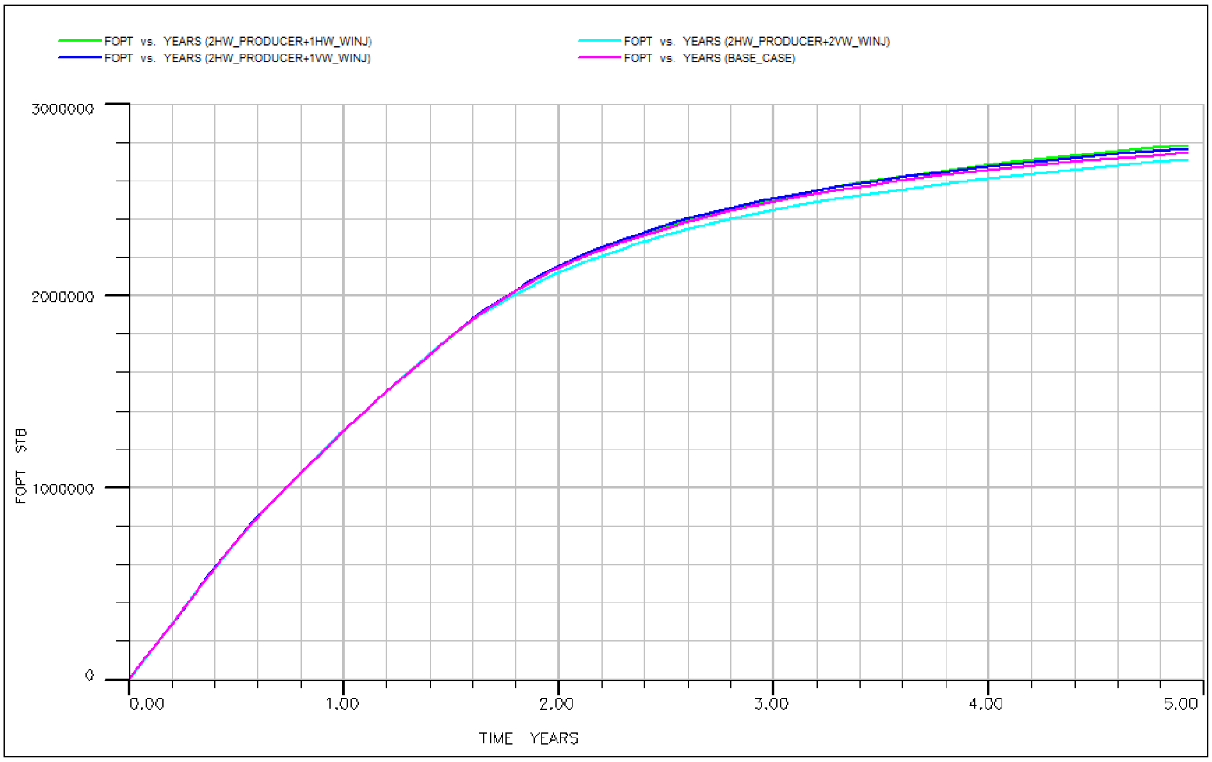

Figure 15 Cumulative oil production vs time for different water injection scenarios.

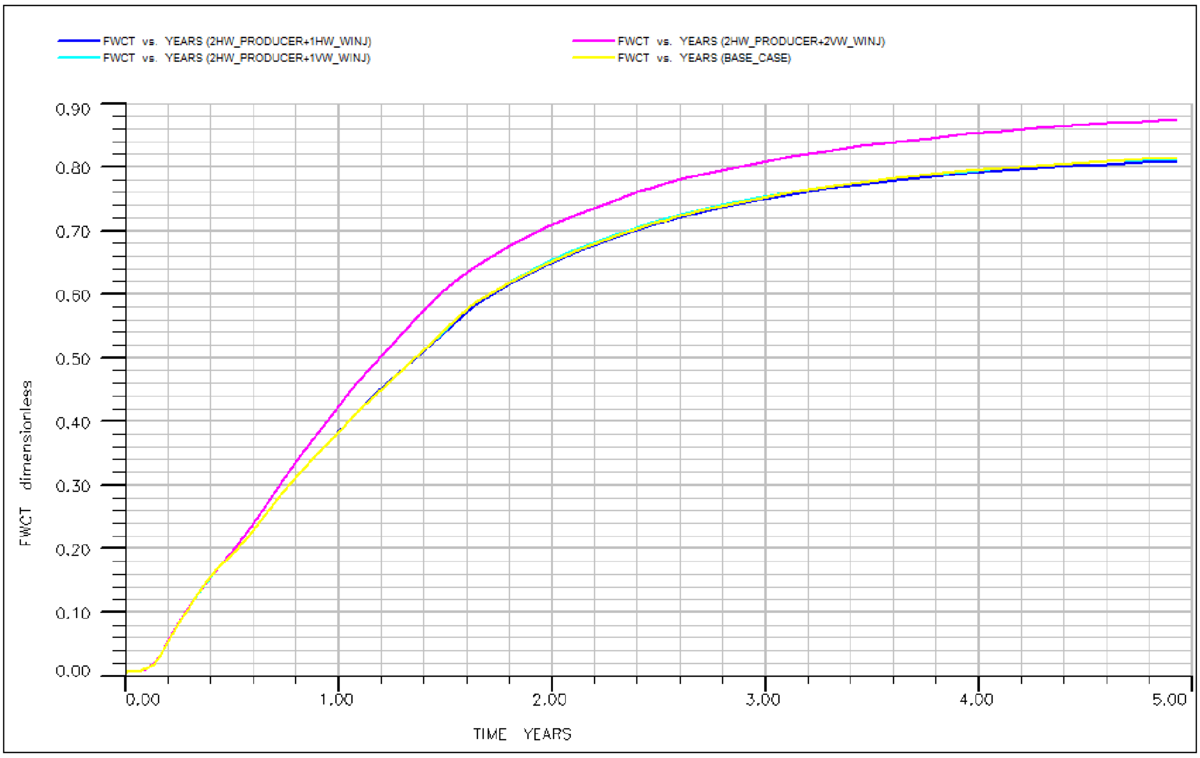

Figure 16 Field water cut vs time for different water injection scenarios.

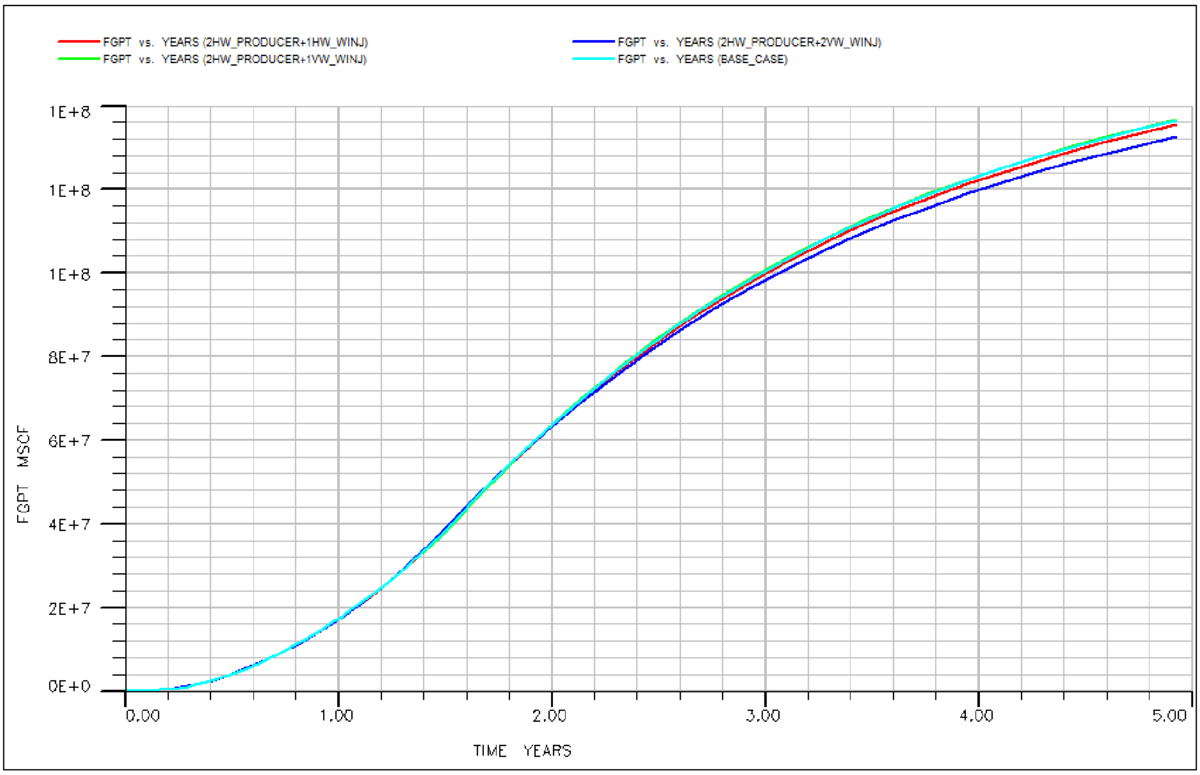

Figure 17 Cumulative oil production vs time for different water injection scenarios.

4.3. Effect of gas injection on oil production

Gas injection is another commonly used secondary recovery technique in oil reservoirs, and it can also be effective in increasing oil production in an oil rim reservoir. In gas injection, gas (usually natural gas) is injected into the reservoir to increase the reservoir pressure and displace oil towards production wells.

When the reservoir is relatively thin, vertical wells may be more suitable than horizontal wells for gas injection, as they can lead to more efficient injection and improved sweep efficiency. According to the figure 18, it is apparent that the maximum oil production can be achieved by injecting gas through two vertical wells and producing oil from two horizontal wells, compared to other scenarios. Over a 5-year period, the cumulative oil production for the two-vertical-well injection case was 4026142.5 stb, whereas the cases of one vertical and one horizontal injector, and the base case yielded 3359492.3, 3539930.3, and 2745440.5 stb of cumulative oil production, respectively.

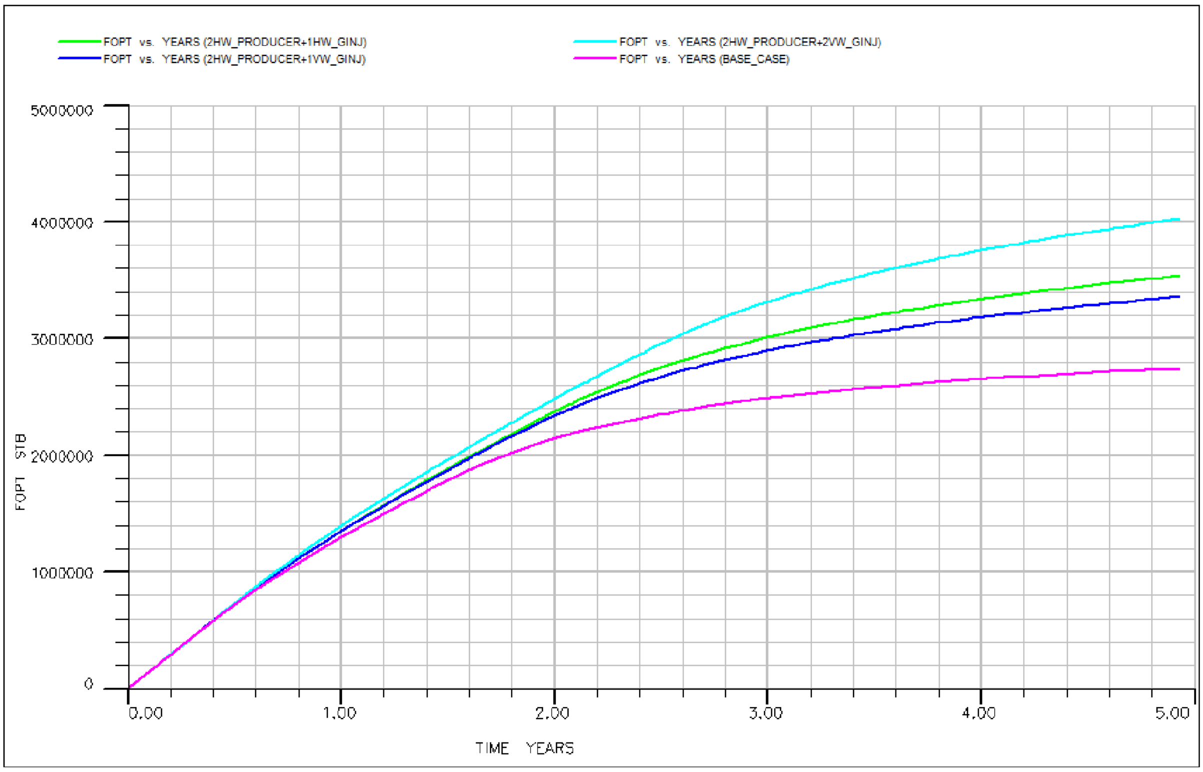

Figure 18 Cumulative oil production vs time for different gas injection scenarios**.**

In an oil rim reservoir, injecting gas can help to sustain reservoir pressure and prevent water from intruding into the oil zone, thereby reducing the amount of water produced. This pressure maintenance is clearly evident from the data presented in figure 19. Furthermore, figure 20 demonstrates that using two vertical injectors (depicted by the purple line) resulted in the lowest water cut percentage (%79) compared to other scenarios. Conversely, gas injection resulted in an increase in the gas oil ratio, as evidenced by the figure 21. The injection gas injection through two vertical wells caused gas production to increase by 20% (from 1.3647 x1011 to 4.069x1011 scf).

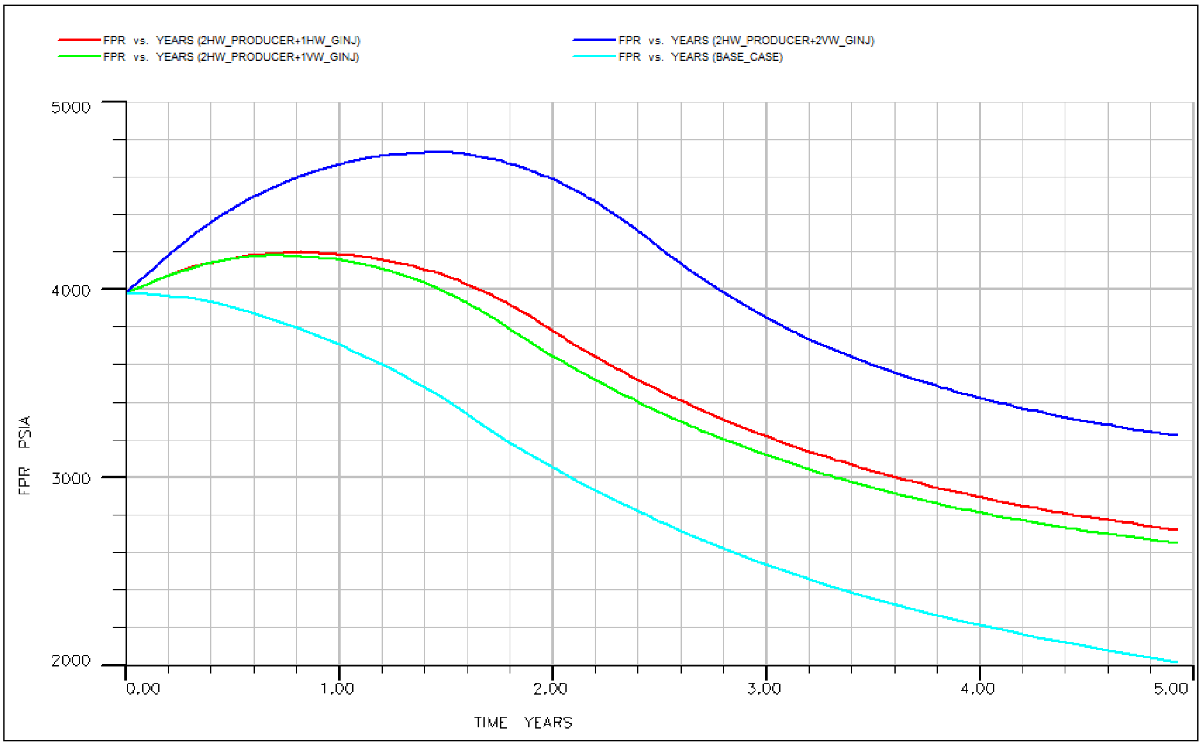

Figure 19 Field reservoir pressure vs time for different gas injection scenarios.

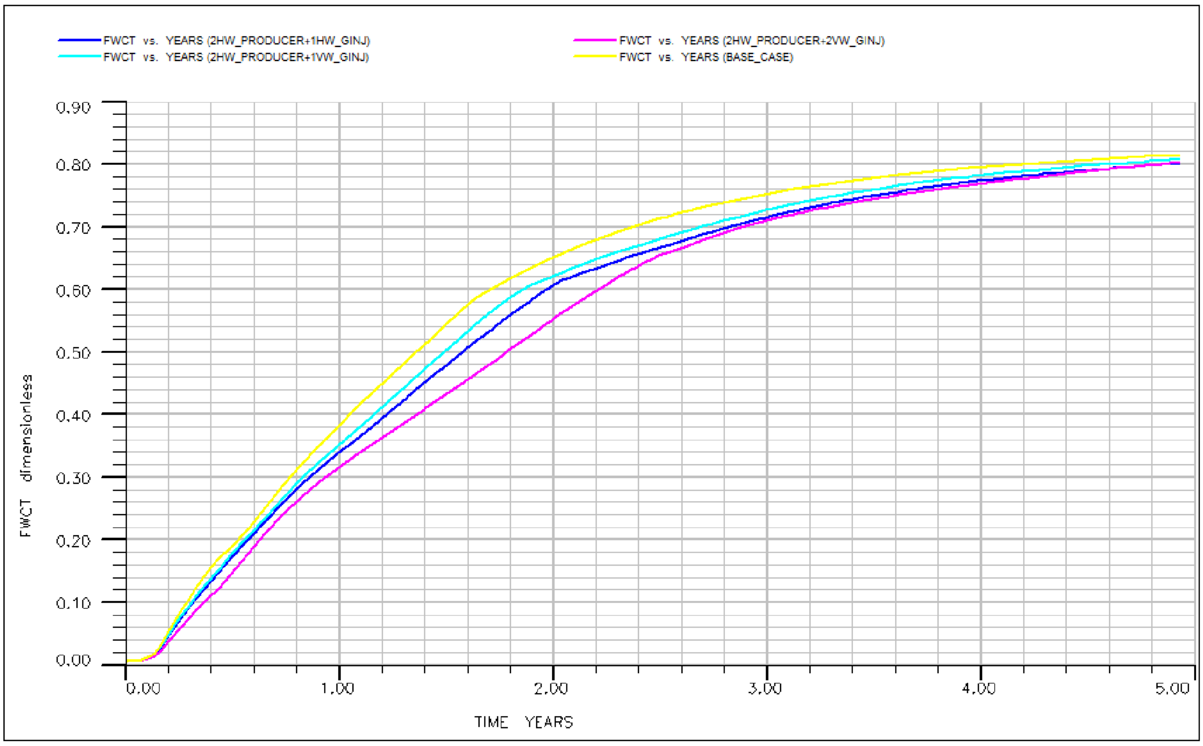

Figure 20 Field water cut vs time for different gas injection scenarios.

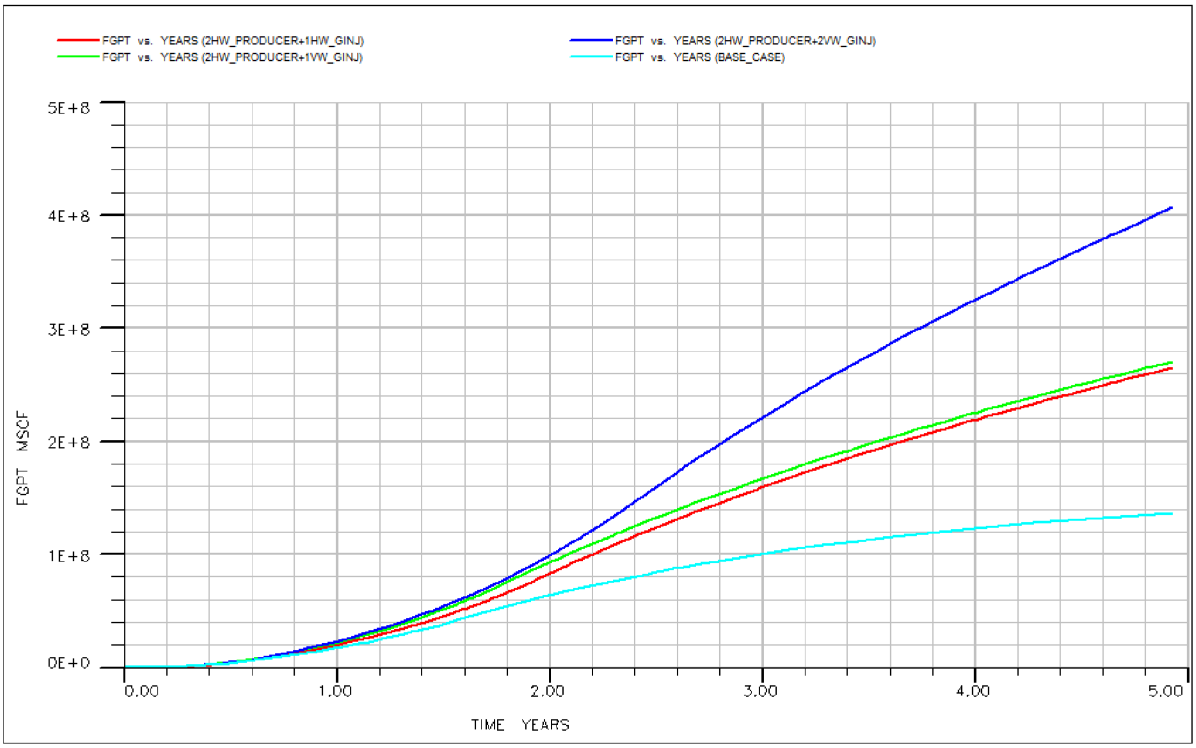

Figure 21 Cumulative gas production vs time for different gas injection scenarios.

4.4. Effect of well placement on oil production

Well placement with respect to the water-oil contact and gas-oil contact can have a significant impact on oil production in oil rim reservoirs. Placing the well too low can result in early water breakthrough, while placing it too high can lead to premature gas breakthrough, reducing oil recovery. Figure 22 show cumulative oil production vs time for different well placement with respect to WOC and GOC. As gas and water have different viscosities, gas tends to move faster than water. Hence, it is more beneficial to place the well away from the gas-oil contact (GOC) to increase oil production. From Figure 22, it is evident that when the well is placed closer to the GOC, the oil production reduces. The most effective placement is at a depth of 36 feet below the GOC and 26 feet above the water-oil contact (WOC), which results in a maximum oil production of 2920763.5 stb compared to the other scenarios. In term of water gas production, it's obvious in figures 23 and 24 that the closer to the contacts the sooner breakthrough will occur. Therefore, placement of wells in relation to the water-oil and gas-oil contacts is crucial for optimizing oil recovery in oil rim reservoirs. Proper placement can enhance sweep efficiency, delay gas and water breakthrough, and maintain pressure in the reservoir, all of which can improve oil production.

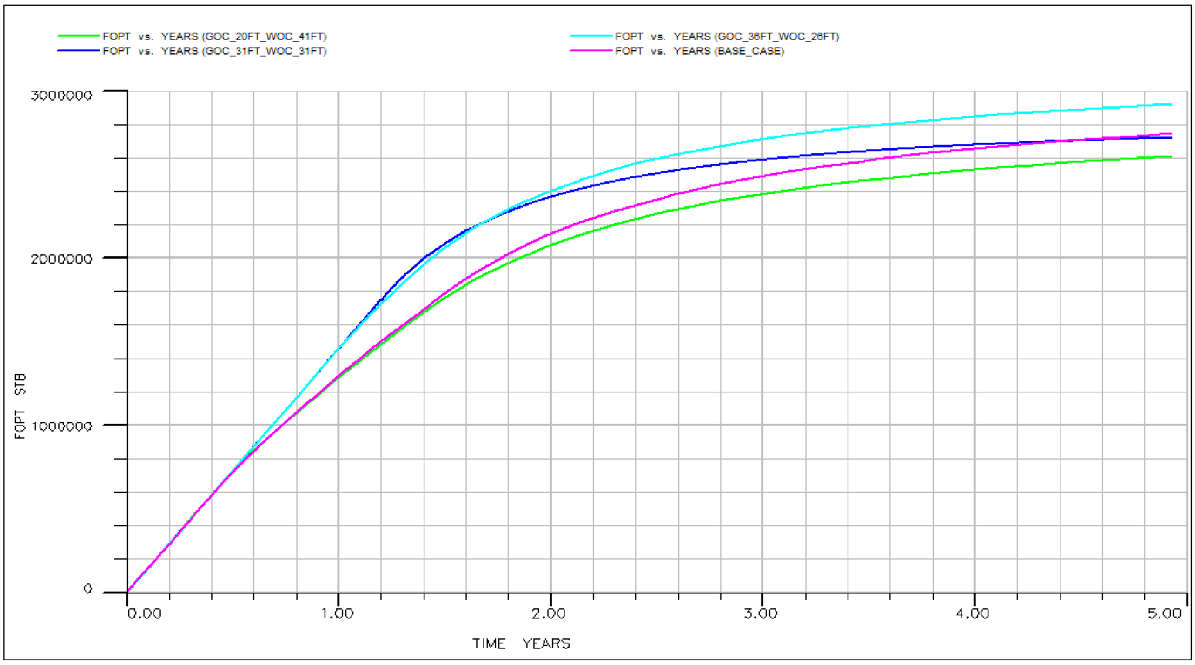

Figure 22 Cumulative oil production vs time for different well placement with respect to WOC and GOC.

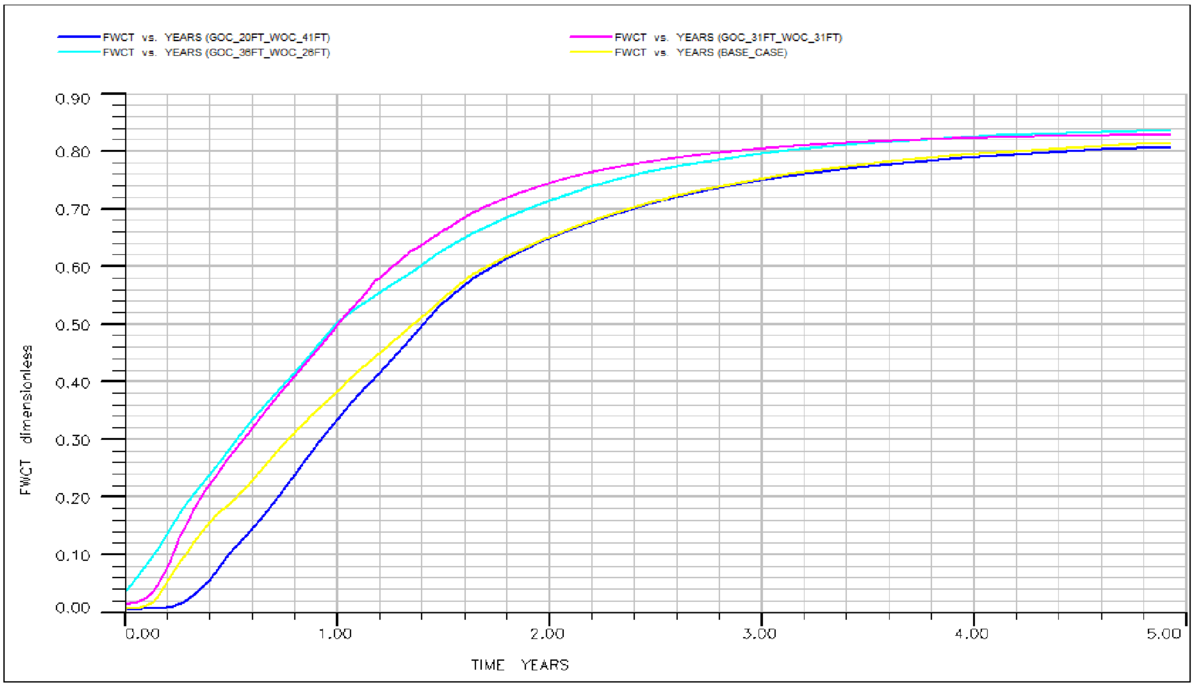

Figure 23 Field water cut vs time for different well placement with respect to WOC and GOC

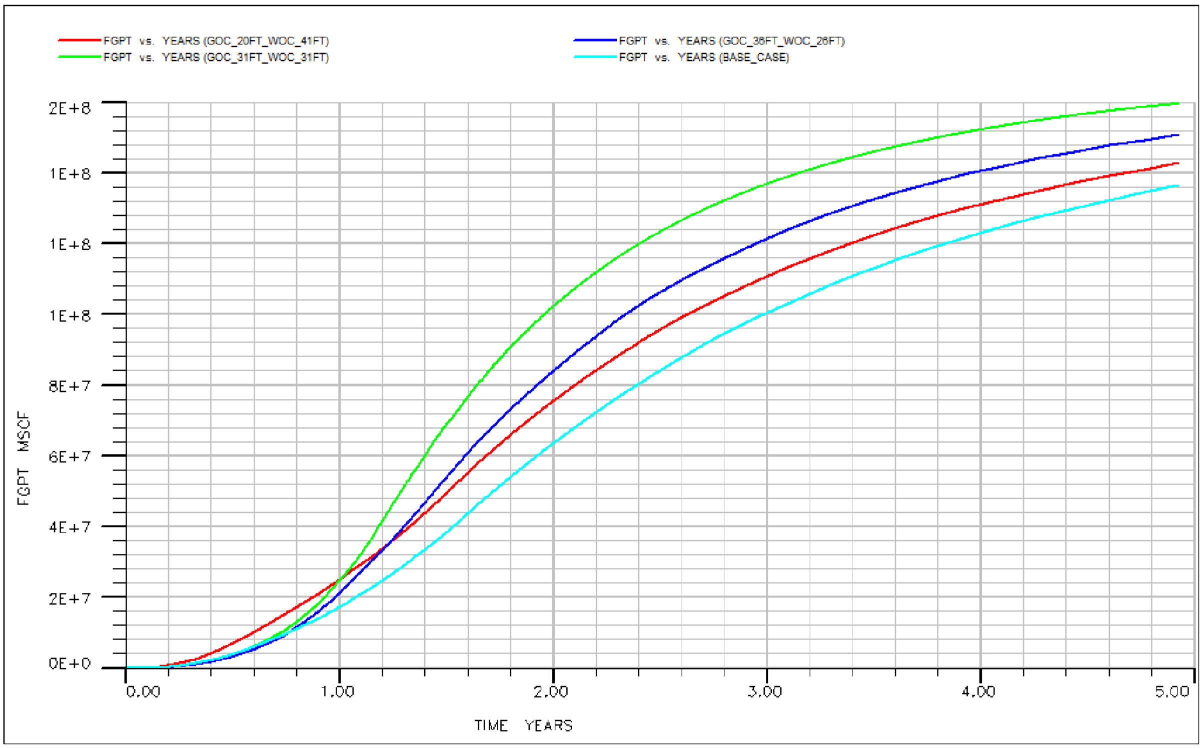

Figure 24 Cumulative gas production vs time for different well placement with respect to WOC and GOC.

5. Summary

The work aimed to optimize oil production from an oil rim reservoir by considering several key factors, including the length of horizontal wells, the type of wells employed, the injection fluid used, and the strategic placement of wells relative to the water-oil contact (WOC) or gas-oil contact (GOC).

In summary, the project highlighted the benefits of drilling longer horizontal wellbores, including increased oil production and subsequent gas production expansion. The findings emphasized the significance of optimizing the length of wellbores to achieve maximum economic efficiency in oil production operations. Furthermore, water injection in oil rim reservoirs proved highly effective in preserving the gas cap and sustaining high oil production rates. Additionally, the simulation study revealed that vertical wells are particularly well-suited for efficient gas injection in thin reservoirs, contrasting with horizontal wells. Moreover, the study demonstrated the substantial impact of well placement relative to the water-oil contact (WOC) and gas-oil contact (GOC) on oil production in oil rim reservoirs.

6. Conclusions and recommendations

6.1. Conclusions

The successful development of oil rim reservoirs can be challenging and may result in low oil recovery if the various factors that determine field development are not thoroughly understood. The objective of this project was to predict the production performance of a horizontal well in oil rim reservoir using the Eclipse simulator. Through multiple simulations and analyses, different scenarios were examined, including injection fluids, well length, types of well and well placement strategies. The main conclusions drawn from the study are:

- Comparisons with a base case revealed that increasing the length of the horizontal well from 1800 ft to 2700 ft led to a 17.5% improvement in oil production.
- Water injection through horizontal wells yielded the highest oil production compared to vertical wells.
- Gas injection through two vertical wells generated an additional 20% of oil production.
- The simulation study identified the optimal well placement depth to be 36 ft below the gas-oil contact (GOC) and 26 ft above the water-oil contact (WOC), resulting in maximum oil production compared to other scenarios.

6.2. Recommendations

- Perform a comprehensive economic analysis to evaluate the viability and profitability of horizontal well production in thin oil rim reservoirs. Consider factors such as drilling and completion costs, operational expenses, oil price forecasts, and return on investment to assess the economic feasibility of implementing this production strategy.

- Investigate upscaling techniques to accurately represent the behavior of thin oil rim reservoirs at the field scale. This can help in transferring simulation results from small-scale models to full-field reservoir models, enabling more accurate production predictions and optimization strategies.

- Develop optimization strategies for horizontal well placement, completion design, and production operations specific to thin oil rim reservoirs. This may involve investigating innovative completion techniques, artificial lift methods, or water and gas injection strategies to maximize oil recovery and improve overall production performance.

- Well Placement Optimization: Investigate different well placement strategies, including variations in horizontal well lengths, distances from the water-oil contact, and gas-oil contact, to optimize the location of horizontal wells in thin oil rim reservoirs. This optimization can be performed using algorithms or artificial intelligence (AI).

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Appendix A

Relative permeability and capillary pressure data used in the reservoir model

Table 1. Show gas relative permeability and capillary pressure data for the oil-gas system

Gas Saturation (Sg)	Gas relative prem (Krg)	Oil/gas capillary pressure (Pc_{go})
0.00	0	0
0.05	0	0.03
0.09	0.032	0.1
0.18	0.089	0.3
0.27	0.164	0.6
0.36	0.253	1
0.45	0.354	1.5
0.54	0.465	2.1
0.63	0.586	2.8
0.72	0.716	3.6
0.81	0.854	4.5
0.90	1	5.5

Table 2. Show Water relative permeability and capillary pressure data for the oil-water system

Water Saturation (Sw)	Water relative prem (Krw)	Oil/water capillary pressure (Pc_{wo})
0.1	0	20
0.16	0.0005	9
0.22	0.004	5
0.28	0.0135	4.1
0.34	0.032	3.3
0.4	0.0625	2.6
0.46	0.108	2
0.52	0.172	1.5
0.58	0.256	1.1
0.64	0.356	0.8
0.7	0.5	0.6
0.8	0.667	0.3
0.9	0.833	0.1
1	1	0

Table 3. Show oil relative permeability data

Oil Saturation (So)	Oil relative prem (Kro)
0.3	0
0.36	0.32
0.42	0.089
0.48	0.164
0.54	0.253
0.6	0.354
0.66	0.465
0.72	0.586
0.78	0.716
0.84	0.854
0.9	1

Appendix B

Base case data file

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WATER
GAS
DISGAS
FIELD
EQLDIMS
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EQLOPTS
'QUIESC'                    'MOBILE'   /
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WELLDIMS
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NSTACK
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/
MULTIPLY
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  0.13700 1214.70 1.17200 1.97000 /
  0.19500 1414.70 1.20000 1.55600 /
  0.24100 1614.70 1.22100 1.39700 /
  0.28800 1814.70 1.24200 1.28000 /
  0.37500 2214.70 1.27800 1.09500 /
  0.46500 2614.70 1.32000 0.96700 /
  0.55800 3014.70 1.36000 0.84800 /
```

```
  0.66100 3414.70 1.40200 0.76200 /
  0.77000 3814.70 1.44700 0.69100
          4214.70 1.44050 0.69400
          4614.70 1.43400 0.69700 /
/
PVTW
 3814.7000   1.02310    3.10E-06   0.94000    0.00E+00 /
GRAVITY
 35.0000  1.00960  0.75000 /
ROCK
 3214.70       0.40E-05 /
SGFN
   0.0000 0.0000 0.0000
   0.0500 0.0000 0.0300
   0.0900 0.0320 0.1000
   0.1800 0.0890 0.3000
   0.2700 0.1640 0.6000
   0.3600 0.2530 1.0000
   0.4500 0.3540 1.5000
   0.5400 0.4650 2.1000
   0.6300 0.5860 2.8000
   0.7200 0.7160 3.6000
   0.8100 0.8540 4.5000
   0.9000 1.0000 5.5000
/
SOF3
   0.3000 0.0000 0.0000
   0.3600 0.0320 0.0010
   0.4200 0.0890 0.0080
   0.4800 0.1640 0.0275
   0.5400 0.2530 0.0640
   0.6000 0.3540 0.1250
   0.6600 0.4650 0.2160
   0.7200 0.5860 0.3430
   0.7800 0.7160 0.5120
   0.8400 0.8540 0.7290
   0.9000 1.0000 1.0000
/
SWFN
   0.1000 0.0000 20.000
   0.1600 0.0005 9.0000
   0.2200 0.0040 5.0000
   0.2800 0.0135 4.1000
   0.3400 0.0320 3.3000
   0.4000 0.0625 2.6000
   0.4600 0.1080 2.0000
```

```
   0.5200 0.1720 1.5000
   0.5800 0.2560 1.1000
   0.6400 0.3650 0.8000
   0.7000 0.5000 0.6000
   0.8000 0.6670 0.3000
   0.9000 0.8330 0.1000
   1.0000 1.0000 0.0000
/
RPTPROPS
   'PVTO' 'PVDO' 'PVTW' 'PVTG'  'PVDG' 'DENSITY'  'GRAVITY'  'SDENSITY'  'MLANG'
   'MLANGSLV'  'TRACER'
/
SOLUTION
==================================================================
RSVD
   6000.0  0.7700
   8000.0  0.7700
/
EQUIL
 7213.5 4000.00 7247.00 0.00000 7180.00 0.00000     1      0      10 /
DATUM
  7000.000 /
RPTSOL
'SWAT' 'SGAS' 'RESTART=2'  'FIP=1' /

SUMMARY
==================================================================
SEPARATE
FOPR
FWCT
FGOR
FOE
FOPT
FWCT
FPR
FGPR
FWPR
WOPR
  'PROD2'    /
WGPR
  'PROD2' /
ALL
MSUMLINS
MSUMNEWT
TIMESTEP
TCPU
```

```
TCPUDAY
SCHEDULE
=========================================================================
RPTSCHED
FIP=1 CPU=2 WELLS  SUMMARY  NEWTON /
DRSDT
  1.000E+20 /
WELSPECS
'prod    ','G       ',  18,  1,7213.5,'OIL'
   1*  ,'STD','STOP','YES',1*  ,'SEG',   /
'prod2    ','G       ',  18,  1,7213.5,'OIL'
   1*  ,'STD','STOP','YES',1*  ,'SEG',   /
/
COMPDAT
'prod    '   18   6    7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod    '   17   6    7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod    '   16   6    7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod    '   15   6    7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod    '   14   6    7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod    '   13   6    7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod    '   12   6    7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod2    '   15   18   7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod2    '   14   18   7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod2    '   13   18   7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod2    '   12   18   7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod2    '   11   18   7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod2    '   10   18   7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
'prod2    '   9    18   7    7 'OPEN'  1*    1*    1.0200   1*      1*      1*     'X' /
/
WCONPROD
'PROD*' 'OPEN' 'ORAT' 2000  4*  1500   /
 'PROD2*' 'OPEN' 'ORAT' 2000  4*  1500   /
/
RPTSCHED
  'RESTART=2'  'FIP=1' 'WELLS=1'  'SUMMARY=1'  'CPU=2' 'WELSPECS' 'NEWTON=1'
/
TSTEP
   30*60
/
END
```