

Optimization of Infill Well Placement in Clastic Reservoirs of Toma South Oilfield

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Research Article

Keywords:

Posted Date: September 10th, 2026

DOI: <https://doi.org/10.21203/rs.3.rs-10728707/v1>

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Additional Declarations: No competing interests reported.

OPTIMIZATION OF INFILL WELL PLACEMENT IN CLASTIC RESERVOIRS OF TOMA SOUTH OILFIELD

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ABSTRACT

The Toma South oilfield which located in the Muglad Basin of South Sudan has been producing oil since its discovery in early 1999 from two main clastic reservoirs namely, Bentiu and Aradeiba formations. Although it has a good recovery factor of about 50.2%, it is believed that a significant volume of bypassed oil has remained untapped due to its reservoir heterogeneity coupled with the issues of compartmentalization and lack of infill well drilling since the field was put in production. This study will therefore aim to optimize infill well placement in clastic reservoirs of Toma South Oilfield to maximize oil recovery while also accessing the economic viability of the infill well placement since there are some challenges posed by the geological complexities and operational constraints.

To achieve the objectives of this study, a comprehensive reservoir simulation model was therefore developed using PETREL and T-Navigator software for simulating the model developed to mimic the behavior of the reservoir by integrating the geological, geophysical, petrophysical and production data of the field. The model then underwent rigorous validation process through history matching the reservoir pressure, water cut trends and cumulative productions to ensure accuracy in representing the field conditions. Production forecasts and scenarios analysis were done for Base case scenario (do-nothing) and other optimization cases like drilling vertical, horizontal and directional wells as well as artificial lift optimization.

The simulation results later revealed that horizontal wells were able to offer the highest incremental recovery, hence improving the recovery factor by 4.8%, giving a cumulative oil production increase of 17.3 MMstb by 2028. Horizontal wells also proved economic superiority compared to scenarios by having a NPV of \$215.46 million, IRR of 29% and the shortest payback period of 2.5 years. Vertical wells showed moderate recovery improvements of 3.5% and economic viability in thicker zones like Bentiu 1A and 1D while directional wells provided flexibility in targeting bypassed hydrocarbon near fault achieving recovery improvement of 4.2%. artificial lift, however, showed limited economic benefits due to its high operational cost associated with increased water handling.

The key recommendation in this study is therefore to drill six (6) horizontal wells in Toma South Oilfield with ESP optimization in the existing wells. The study therefore highlights the importance of integrating the advanced reservoir simulation, economic analysis and innovative well design to optimize field development. These findings and recommendations provide a roadmap for maximizing recovery and profitability in Toma South oilfield hence contributing to South Sudan economic growth objectives.

MANUSCRIPT CONTENT

title

Abstract

Keywords

1. Introduction

2. Literature Review

3. Methodology

4. Results and Discussion

5. Conclusions and recommendations

Declarations

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1: INTRODUCTION

1.1 OVERVIEW

In maturing oilfields, tertiary recovery methods such as waterflooding and gas flooding are employed to maintain reservoir pressure and sustain production levels. However, these methods often fail to extract all the oil between producing wells, prompting the drilling of infill wells to capture otherwise unreachable hydrocarbons. Despite the rising availability of alternative energy sources like solar energy, global demand for hydrocarbon fuels remains high. Infill wells play a crucial role in enhancing reservoir drainage amidst challenges in reservoir heterogeneity, compartmentalization, porosity, and permeability, thus optimizing production and minimizing economic risks associated with infill well drilling.

The Toma South Oilfield, located southwest of Block 1A in the Greater Pioneer Operating Company (GPOC) concession within the Muglad Basin of South Sudan, has been significant for the country's oil production, commencing production in October 1999. The field has relied on approximately 25 active oil producers with no new infill wells drilled since inception. The active water drive mechanism has resulted in a recovery factor of about 56%, indicating considerable potential hydrocarbon reserves.

Past studies highlight that improper placement of infill wells leads to suboptimal oil recovery, necessitating a thorough investigation into well placement strategies in this thesis. A reservoir simulation using Petrel models and Eclipse models will be conducted to evaluate the performance of infill wells at various locations within the field's two main reservoirs: Aredeiba and Bentiu, which exhibit different productive indices due to pressure variances.

1.2 PROBLEM STATEMENT

Despite years of production, significant hydrocarbons remain unrecovered in the Toma South oilfield, facing several challenges:

- Declining production rates attributed to natural depletion and inefficient drainage.
- Water breakthroughs in existing wells that diminish sweep efficiency.
- Economic constraints impacting drilling strategies with a need for cost-effective in-fill placements.
- Reservoir heterogeneity in clastic formations causing uneven fluid movement and bypassed production zones.

The primary challenge lies in determining optimal infill well locations for maximum recovery while ensuring economic viability amid fluctuating oil prices. Thus, a robust in-fill well placement strategy addressing geological uncertainties, dynamic reservoir performance, and economic aspects is critical.

1.3 RESEARCH AIM AND OBJECTIVES

This study aims to:

1. Develop a predictive reservoir simulation model for various production scenarios based on different infill well placements.
2. Evaluate current reservoir performance to identify areas with untapped hydrocarbon potential.
3. Determine optimum well spacing and completion strategies tailored to identify infill well locations.
4. Assess the impact of geological reservoir heterogeneity on infill well production.
5. Conduct economic analyses to validate the feasibility of the proposed infill drilling program and its effects on overall recovery factors.

The study will explore questions regarding factors affecting infill well drilling success in heterogeneous reservoirs, economic viability of optimized drilling programs, and geological characteristics hindering performance.

1.4 SIGNIFICANCE OF THE STUDY

This research is significant for multiple reasons:

- It will propose methods to enhance oil recovery in Toma South by identifying optimal infill well locations.
- The methodologies can serve as reference points for similar studies within the Muglad Basin and South Sudan.
- It supports economic decision-making by providing comparative insights between drilling expenses and recovery benefits.
- The study aligns with South Sudan's national goals to maximize oil recovery for economic stability.

Scope and limitations include a focus on clastic reservoirs specifically within Toma South Oilfield, employing Numerical Reservoir Simulation via oil and gas industry software, and conducting economic analysis using Microsoft Excel to evaluate Net Present Value (NPV) and Internal Rate of Return (IRR). Limitations arise from restricted data availability reliant on historical production logs and assumptions in reservoir simulations regarding specific locational parameters.

1.5 THESIS ORGANIZATION

To achieve the stated aims and objectives, this dissertation is structured as follows:

- 1: Introduction,
- 2: Literature Review,
- 3: Methodology and Data Summary,
- 4: Results and Discussions,
- 5: Conclusions and Recommendations.

2: LITERATURE REVIEW

2.1 OVERVIEW OF CLASTIC RESERVOIRS

Clastic reservoirs are common types of hydrocarbon reservoirs that are usually found in Muglad basin where Toma South Oilfield is located. They are a type of sedimentary rocks that are made up of particles of pre-existing rocks that have been transported by either wind or water and deposited which then lithified over a long period of time. The behavior and properties of critical reservoir are very important to study for successful hydrocarbon exploration. according to the study done by [1]they emphasized that reservoir heterogeneity is the major cause of uneven fluid distribution resulting in bypassing of some oil hence poor sweeping of oil to the producing well. this section will focus on discussion of the formation of clastic reservoirs, their characteristics and challenges while relating them to Toma South Oilfield.

2.1.1 FORMATION AND DEPOSITIONAL ENVIRONMENTS OF CLASTIC RESERVOIRS

The formation of the clastic reservoirs is through erosion, transportation, deposition and then the lithification of the sediments that had been formed from the pre-existing rocks. The various environments in which these sediments are deposited are the major factors which contribute to the uniqueness of the reservoir.

The formation process of clastic reservoirs involves the following processes.

It begins with the weathering and erosion of rocks which are then transported by transportation agents like winds, water and glaciers, until at the point when the transportation agents lost energy and it then deposited at that point. It is a depositional environment that has much influence on the reservoir heterogeneity and its architecture. These sediments deposited are then compacted and cemented by the reaction of the minerals in a process called lithification forming a sedimentary rock like sandstones, conglomerate and siltstones which are good reservoir rocks.

The common depositional environments of clastic reservoirs are as follows:

Fluvial system whereby rivers deposits sediments in their channels, floodplains and deltas. These depositional environments are usually associated with high heterogeneity of their reservoirs due to the differences in flow energy of the river depositing sediments and sediment supply. according to the studies done by [2]. The Bentiu formation, which is one of the oil reservoirs of Toma South was deposited by the braided fluvial system that gave rise to thick sand bodies that are interbedded with impermeable shale while shale is one of the geological features that hinders uniform drainage of the reservoir. If the fluvial system was created by braided rivers that usually results into well sorted sands, then it will have an advantage of having a high porosity of up to 30% and a disadvantage of a

lateral discontinuity due to channel migration. However, if the fluvial system was created by a meandering river, it will result in fine grained pointed bar usually with a floodplain deposit with advantage of having sediments that have a good vertical stacking potential and a disadvantage of creating a shale drape that usually acts as flow barriers in a reservoir.

The deltaic system that is formed where rivers meet standing water bodies like seas and lakes. This system usually forms a reservoir that has a complex distribution of facies and a reservoir with different compartments. The delta front sands usually result in a high-quality reservoir that is made up of sheet-like geometry while the distributary channels usually result in a high permeable reservoir that is always prone to mud clogging.

The shallow marine systems are sediments that are deposited on a coastal area resulting in the formation of reservoirs that have a uniform and laterally large extensive sand bodies.

The aeolian systems result from sediment deposits that were transported and deposited by wind. They characteristic of aeolian systems is that it forms reservoirs which have high porosity and permeability but with a limited lateral continuity.

The reservoirs of Toma South oilfield are predominantly composed of fluvial-deltaic sandstones which are characteristics of clastic reservoirs. Such depositional environments as discussed above are very heterogeneous reservoirs that have a high varying degree of porosity, permeability and connectivity that usually have notable influence on hydrocarbon recovery and infill well optimization.

2.1.2 GEOLOGICAL PROPERTIES OF CLASTIC RESERVOIRS

The ability of clastic reservoirs to trap, store and flow hydrocarbon in the reservoir is majorly determined by its geological properties mentioned below.

Porosity being the percentage of void space in the reservoir that can store the hydrocarbons. This geological property has serious effects on the productivity of the hydrocarbons reservoirs as the reservoirs with high porosity values always give high productivity rates compared to the reservoirs that are very tight with low porosity values. Clastic reservoirs usually have a porosity range of 10 to 30% in most cases (Wells et al., 2019).

Permeability is another geological property that has an impact on the production of clastic reservoirs. It is the ability of the reservoir rock to transmit fluid. This property is mostly influenced by the grain size, sorting and the cementation in clastic reservoirs. Reservoir rocks with well sorted like sandstones mostly exhibit higher permeability.

The heterogeneity as one of the geological features of clastic reservoirs refers to the variation of reservoirs properties as a function of space. It largely affects the recovery of

hydrocarbon and well placement in the reservoir because high heterogeneity results in bypassed oil zones that require drilling infill well to produce that bypassed oil. Vertical heterogeneity results from the variations in porosity and permeability against depth due to the layering of different types of sediments like sandstones and shales while lateral heterogeneity results from the differences in reservoir properties across the field mainly due to the changes in the depositional environment.

The connection between the sand bodies of the reservoir or reservoir compartments is very important for the fluid flow. Other geological properties like the shale barriers, fault and low permeability zones can create compartments in the reservoir which usually has effect on the efficiency of primary and secondary recovery methods of hydrocarbons [4].

The distribution of the reservoir fluids such as oil, gas and water is based on the geological structure, permeability of the reservoir and its capillary pressure. Water-oil contacts and gas-oil contacts that are usually seen in clastic reservoirs which mostly influence well performance.

2.1.3 IMPLICATIONS FOR INFILL WELL PLACEMENT IN TOMA SOUTH OILFIELD

It is important to note that the geological and petrophysical properties of clastic reservoirs always have challenges that directly affect well placement in Toma South Oilfield. The following geological and petrophysical properties have been identified to have implications for infill well placement in clastic reservoirs.

Some compartments in the field may be isolated by the faults and shale barriers hence care should be taken to correctly locate these infill wells to access the untapped reserves in the field.

Due to the high degree of heterogeneity in Toma South's Fluvial -deltaic reservoirs, there is a need for clear detailed reservoir characterization so that zones that have bypassed oils can be identified.

There is a need for integrating production data with the geological model of the field so that dynamic factors like water breakthrough and pressure depletion can be studied.

Determination of the optimal well spacing in the reservoir so that the infill wells does not interfere with the existing wells is very important to ensure maximum recovery from the field.

In summary, the clastic reservoirs of Toma South oilfield are sedimentary rocks by origin that are heterogeneous with compartmentalization. The heterogeneity and compartmentalization make efficiency recovery of hydrocarbons challenging hence making optimized infill drilling the only alternative to produce the bypassed oil. Understanding the geological and petrophysical characteristics of Toma South reservoirs

is important so that effective strategies for efficiently recovering hydrocarbons can be developed. The main goal of this study is to address the challenges of placing infill wells in clastic reservoirs by identifying the best location for these infill wells in Toma South Oilfield.

2.2 INFILL WELL PLACEMENT IN MATURE OILFIELDS

2.2.1 DEFINITION AND OBJECTIVE OF DRILLING INFILL WELLS

Drilling infill wells refers to the process of drilling additional wells in the field between the existing production or injection wells with the purpose of increasing hydrocarbons recovery from the reservoir. They are drilled in the field that has been producing for a long time to address issues like inefficiencies in reservoir drainage. It is one of the critical strategies in the development of most mature oilfields like Toma South for efficient hydrocarbons recovery. Mature oil fields are always faced with lot of problems like the decline in production rates, uneven in reservoir drainage and bypassed hydrocarbon zones. Strategic placement of the infill wells can solve the above-mentioned problems by targeting the upswept hydrocarbon zones hence increasing the production of the field. The main purpose of this section is to explore the concept of infill drilling, their importances, challenges usually experienced in infill well drilling and similar case studies on infill well placement in mature oilfield with focus on how they can apply in clastic reservoirs like those of Toma South oilfield. The full field review (FFR) done on Toma South in 2006 identified that there is 12 MMstb of bypassed oil in sealed fault compartment which can only be extracted by drilling infill wells in it. Below are the primary objectives of infill well placement in most mature oilfields:

The first major objective of infill well placement is to maximize hydrocarbon recovery by being able to access bypassed oil and gas that was not produced by the primary and secondary recovery methods.

Infill well drilling has an advantage of reducing the average distance between the wells. This hence improves the reservoir sweep efficiency, leading to an increase in production of the field.

They can enhance the production rates of the field for a short to midterm period if they are strategically placed to tap zones with remaining hydrocarbons (Lumley, 2001).

They help to mitigate the declining production rates of the field since most mature fields are faced with problems of decline due to pressure decline and rising high water cuts.

The decline in production rates of Toma South oilfield makes infill well placement at strategic locations in the field a viable option for production optimization. The complex geological and petrophysical properties like heterogeneity and compartmentalization require critical analysis while placing the infill wells. the selection criteria for placing the

infill wells will be based on geological area with high remaining oil saturation, good porosity and high permeability.

2.2.2 IMPORTANCES OF INFILL WELLS IN CLASTIC RESERVOIRS

Being heterogeneity with faults, shale barriers and compartments makes extraction of hydrocarbons challenging in clastic reservoirs. Drilling infill wells in this reservoir is important because of the following:

1. The lateral and vertical variations in reservoir properties that are usually created by the fluvial and delta depositional environments of clastic reservoirs can be easily minimized since drilling infill wells allow the operating company to tap the isolated sand bodies that were impossible to produce using the existing wells.
2. Due to the heterogeneity of the clastic reservoirs, some zones containing good volume of hydrocarbons can be poorly swept by both primary and secondary recovery methods due to may be a variation in the permeability of the reservoir or shale barriers so infill well can easily tap these zones.
3. Drilling infill wells in clastic reservoirs helps to improve sweep efficiency by mitigating uneven hydrocarbon fluid movement in the reservoir that is caused by heterogeneity as per [6]
4. Infill drilling helps to enhance the recovery factor of the clastic reservoir since they have lower recovery factors compared to carbonate reservoirs because of their geological complexity. A study done by [7] concludes this finding.

There are two types of infill wells that can be used Toma South oilfield, the vertical wells can be used to tap the Aradeiba formation that is thin with discontinued sand bodies while the horizontal wells can be ideal for Bentiu formation that has a high permeability channel.

2.2.3 CHALLENGES MOSTLY FACED IN INFILL WELL PLACEMENT

Although infill wells usually have better rewards after drilling them in the reservoir, their placement in mature field like Toma South with clastic reservoir do have some challenges as outlined below:

1. There is a problem of pressure depletion and production interference if infill wells are placed too close to the already existing wells in the field.
2. Due to the heterogeneous nature of clastic reservoirs, it is usually difficult to identify the best locations to place the infill wells. big variation in permeability, porosity and fluid saturation make it difficult to choose the best location for the infill wells (Arinkoola et al., 2016).
3. The full field review study done on Toma South oilfield presents geological uncertainty since there is limited data on the subsurface geology of the field

which can result in misplacement of the well that can miss the isolated sand bodies containing hydrocarbon.

4. In some cases, the drilling and completion of infill wells is economically more than the existing wells so operating companies in most cases must justify that the cost of drilling an infill well is lower than the expected economic gain from it.
5. Another big challenge with mature fields is that they do exhibit dynamic in reservoir pressure, flow pattern and fluid saturation with time making the placement of infill wells challenging.
6. Misplacement of infill well in a water zone can result in early water breakthroughs in the nearby well which therefore reduces hydrocarbon recovery and brings a problem of high cost of handling produced water.

2.2.4 STRATEGIES FOR EFFECTIVELY OPTIMIZING INFILL WELL PLACEMENT

Various strategies and methodologies have been developed to optimize infill well placement in the reservoirs

1. Advanced reservoir simulations allow petroleum engineers to be able to predict the performance of reservoirs at different infill well locations under various infill well scenarios. Integration of geological, petrophysical data and production enables the models to be able to identify the un-swept zones in the reservoir. The simulator will then be able to evaluate the impact of proposed infill well on the overall reservoir performance as per the study done by [9]
2. Geophysical mapping by using a high-resolution seismic survey coupled with geophysical studies helps to provide detailed insights into the reservoir structure and its heterogeneity. The time-lapse (4D) data which is acquired from this study is very useful since it is used to track the movement of fluid and identification of bypassed oil zones in the reservoir as per the study done by Lumley, 2001.
3. Advance in machine learning and artificial intelligence have led to invention of advanced techniques like artificial neural networks (ANNs) which are currently being used in some companies to predict the production potential and optimize well placement in the reservoir [10]. These techniques have an advantage of being able to handle large datasets and ability of high prediction accuracy. Xinwei Xiong, 2019 and [11] used artificial neural networks coupled with reservoir simulation for optimization of injection well placement in heterogeneous reservoir while [12] used neural networks to optimize well placement in heterogeneous reservoirs.
4. Determination of the optimal distance between the infill wells and the existing wells is very important as it helps to minimize the interference between the wells and maximize the reservoir recovery factor. Sensitivity analysis to evaluate the impact of different well location and well spacing shall be done in this study to determine the productivity of the proposed infill wells at various locations in the

- reservoir [13]. The locations that shall give the best production rate in the simulation shall be chosen for placing the infill wells.
5. Economic analysis shall be conducted so that the cost-benefit analysis proves the incremental recovery from drilling infill wells justify placing the infill well in the reservoir. Possible associated risks shall be quantified using probabilistic approaches like monte Carlo simulation to account for unseen uncertainties like production forecast, changes in economic factors and reservoir properties. These will help with decision-making so that possible economic risks are mitigated.

2.2.5 SOME CASE STUDIES ON INFILL WELL PLACEMENT

Several case studies have done on infill drilling, and they have shown that infill drilling in mature oilfields particularly in clastic reservoirs is economically feasible if good analysis has been done prior to the drilling. Below are a few examples of case studies on infill drilling so that they can illustrate the challenges faced, methodologies applied and the outcomes of the studies. They also highlighted the best practices that should be followed and the lessons learned which are very important for placing infill wells in Toma South Oilfield.

1. case study 1: North Sea clastic reservoir

This reservoir is in the North Sea composed of fluvial-deltaic sandstones with both lateral and vertical heterogeneity. This field was experiencing a problem of decline in production caused by bypassed hydrocarbons in poorly swept zones of the reservoir. The reservoir pressure of this field was supported by water injection. The main objective of the study was to improve the reservoir drainage and enhance the recovery factor of the field. The first methodology used was a reservoir simulation approach whereby a detailed numerical simulation model was built using seismic data, well logged with the historical production data. The simulation result was able to identify the zones that have not been swept in the reservoir while the 3D seismic data was integrated into the simulation model which was then used to map the sand bodies distribution and help in the identification of the connected sand bodies that have untapped hydrocarbon. The outcome was that four infill wells were successfully placed in high potential zones with good remaining hydrocarbon which was identified by the reservoir simulation. This increased the recovery factor of the field by more than 20% by tapping the bypassed oil zones. This case study highlights the importance of integration of seismic data with simulation model for correct placement of wells.

2. case study 2: Middle East thick clastic reservoir

This is a type of reservoir in middle east that has shown high heterogeneity with stacked sand bodies that are mostly separated by the shale layers like the one of Toma South oilfield. This reservoir had been producing for over 20 years but is currently facing a problem of decline in total production rate due to uneven reservoir sweeping. The main objective of this case study was to optimize well spacing for efficient drainage of the

reservoir. The first methodology used was reservoir monitoring and data integration whereby tracer studies and pressure build-up tests were used to know the fluid flow patterns in the reservoir. Then the integration of well-log and seismic data helped in mapping of the reservoir connectivity and identification of the poorly swept zones in reservoir. The second methodology was all about optimization of the well spacing whereby sensitivity was done to determine the optimal well spacing between the existing wells and the proposed infills well in the reservoir. Sensitivity was then done on many well spacing scenarios using reservoir simulation models to determine the optimal spacing. The result of this case study was that five infill wells were successfully drilled with optimal spacing that were able to target the bypassed oil in the isolated sand bodies. The incremental oil recovered from the infill wells was found to be above 15% more than that of the base case scenario. This study was able to highlight the importance of understanding reservoir dynamics and optimization of well spacing for efficient well drilling.

3. Case study 3: South Sudan Muglad basin reservoir.

This is a common sandstone reservoir found in South Sudan especially in block 3 and 7 being operated by Dar Petroleum Operating Company. It is mostly characterized by lateral heterogeneity made up of complex fault system. The historical production data from this field showed that it has a poor sweep efficiency due to heterogeneity with declining production rates. The objective of this case study was to evaluate the feasibility of infill drilling as a method to enhance the recovery of hydrocarbons in that challenging geological setting. The methodology used was an integration of seismic and production data whereby the 3D seismic data was analyzed to help in mapping of faults and understanding of the compartmentalization of the reservoir while the history matching was performed on the production data to identify the areas that have bypassed hydrocarbons. An economic viability assessment was performed before implementing the program to evaluate the return on investment (ROI) on the proposed infill wells. The result of this case study was that two infill wells were successfully drilled in high-potential zones containing hydrocarbons with an increase in oil recovery factor of the field up to 12%. This study therefore highlights the importance of the integration of historical production data with seismic data to help in strategic optimization of infill wells placement in the oilfield.

Having gone through those case studies discussed above, many vital lessons can be learned from them as follows:

- It has been proven that in all those case studies above that data integration is critical for the successful implementation of infill drilling campaigns. Integration of geological, geophysical and historical production data of the field is very important for correct identification of high-potential zones containing hydrocarbons for infill wells.

- Advanced techniques like reservoir simulations and geostatic have helped in the precision of well placement especially in heterogeneous reservoirs like the one discussed above.
- A rigorous economic analysis to ensure that the project is feasible is vital before the implementation of the project to avoid loss. The cost benefit analysis is very important to ensure that incremental recovery from the infill drilling justifies the project. Conducting pilot projects has shown that it mitigates big losses whereby a risk foreseen in pilot projects can be easily mitigated in the actual project.

The findings from the above studies are like those of Toma South oilfield. Being a mixture of fluvial-deltaic clastic reservoirs, it therefore shows similar challenges such as heterogeneity, compartmentalization, isolated sand bodies and bypassed hydrocarbons reservoir. By integrating techniques like reservoir simulation and geostatic, the operating company in Toma South Oilfield can successfully optimize the placement of infill wells that will enhance the recovery of the field leading to an improved production efficiency.

2.3 OPTIMIZATION TECHNIQUES FOR INFILL WELL PLACEMENT

Optimization of infill wells placement is one of the critical tasks for maximizing hydrocarbon recovery in mature oilfields, especially in clastic reservoirs which pose challenges like those discussed above. The complexity of the subsurface conditions necessitates integration of techniques that can combine geological, geophysical and production data with the computational tools [14]. There are therefore various methods that can be used to optimize infill well placement.

2.3.1 THE TRADITIONAL METHODS

Traditional methods have been from the onset of the infill drilling idea in the oil and gas industry for optimizing wells placement. They rely primarily on the geological models, geostatic analyses and the reservoir simulations to determine the best location for placing the infill wells. My thesis will use this method to optimize the placement of infill wells in Toma South Oilfield.

2.3.1.1 RESERVOIR SIMULATION

This traditional method is the most used method for optimizing infill well placement. It involves creating a reservoir model that shall mimic (predict) fluid flow while evaluating performance under various reservoir scenarios. To create a representative reservoir model, there is a need to start by building a detailed geological model using well logs, seismic surveys and core samples. Dynamic data like the production history and pressure measurements are then incorporated into model to calibrate the model. The model is then simulated under various well placement scenarios in the reservoir until the high potential zones that contain bypassed hydrocarbons are chosen for infill wells [15]. This method has the advantage of providing a detailed understanding of fluid flow and reservoir

dynamics. This simulation can be used to evaluate the impact of infill wells on recovery factors of the field and the total field production rates. Its limitations are that it requires high quality data that is free of errors which may not be possible and the computationally intensive which is always time consuming. A typical example of this is a North Sea clastic reservoir whereby reservoir simulation identified unswept zones that have low sweep efficiency which led to successful placement of infill wells at the target zones.

2.3.1.2 GEOSTATISTICAL ANALYSIS

Geo-statistical analysis involves the uses of statistical methods to model spatial variability in reservoir properties like porosity, saturation and permeability. These properties when properly study help to identify regions that have high hydrocarbon potential. There are two techniques that are widely used in this method. The first one is Kriging method which involves interpolation to estimate reservoir properties at unsampled locations while the other techniques is sequential gaussian simulation which is a simulation technique that creates multiple realizations of reservoir properties that account for uncertainty in the data provided. Its limitations are that it depends on the quality and density of the input data, and it does not capture dynamic reservoir behavior. An example of this method application was in a west African sandstone reservoir whereby geo-statistical analysis helped in the mapping of the bypassed zones which gave a result of around 20% increase in the recovery factor of the field by drilling the infill wells.

2.3.2. THE ADVANCED DATA-DRIVEN TECHNIQUES

The advanced data driven techniques use computational algorithms and machine learning to optimize the placement of the infill wells in the reservoir. These methods have an advantage of handling large datasets while also capturing complex and non-linear relationships in the behavior of the reservoir [16].

2.3.2.1 ARTIFICIAL NEURAL NETWORKS (ANNs)

Artificial neural networks are a type of machine learning models that have been inspired by the human brain (What Is a Neural Network? - Artificial Neural Network Explained - AWS, n.d.). They can identify patterns and relationships in complex datasets making them highly desirable for use in reservoir applications. The process involves the input of data such as permeability, water saturation, porosity and production history in the model. The ANN model is then trained by using historical data to predict the production rates for potential locations (Stihec, 2025). The trained model can now be used then to evaluate the various scenarios of well placement to choose the best scenario. ANN has the advantages of capturing non-linear relationships between the reservoir properties and production performance of the reservoir while also able to handle large multi-dimensional datasets. Its limitations are that it requires extensive training data to give accurate

prediction, and the results can be difficult to interpret which needs expertise. An example of this type of is in a middle east mature oilfield whereby an ANN model that was built predicted the production rates for potential infill well locations in the reservoir which resulted in an optimized drilling plan that increase the recovery factor of the field to 25%.

2.3.2.2 MACHINE LEARNING ALGORITHMS

There are other types of machine learning algorithms like random forest, gradient boosting and support vector machines that can also be used for efficient well placement optimization in the oilfield. They can be applied to predict unswept zones based on the analysis of the reservoir and production data of the reservoir. They can also be used to classify well locations into high zones and low zones containing hydrocarbons [17].

They have an advantage of being flexible and adaptable to different types of data and they incorporate uncertainty through probabilistic models. Their major limitations are that they require always expertise that is well verse with data science and reservoir engineering. They also computationally demand large datasets. A typical example of this was on South American fluvial whereby a random forest algorithm helped in identification of the key features that influences production like the proximity of the well to the faults hence enabling the location of infill wells in high potential areas [18].

2.3.2.3 BIG DATA ANALYTICS

The big data analytics involves the application of advanced computational tools that can process and analyze large volumes of reservoir data in real-time. This method is gaining popularity due to the advent in technology of the oil and gas industry (New Technology in the Oil and Gas Industry - Optical Cable Corporation, 2013). They can apply in real time monitoring of the performance of the reservoir and for dynamic optimization of well placement based on the analysis of the real time data. They have the advantage of being helpful in proactive decision making and dynamic well placement. They also have another advantage of being able to reduce uncertainty by frequently updating simulations models with new data [19]. Their major challenges are that they require advanced tools for data collection and processing. A typical example of this was in North American Oilfield whereby big data analytic was used to integrate seismic, production and seismic data that resulted in the real time optimization of the infill well placement.

2.3.3 THE HYBRID APPROACHES

The hybrid approaches are a combination of traditional methods with advanced data driven techniques that are integrated to achieve the optimization of infill well placement.

2.3.3.1 INTEGRATION OF RESERVOIR SIMULATION AND MACHINE LEARNING

This is a type of hybrid whereby reservoir simulation is used to generate synthetic training data for machine learning models. The machine learning algorithms will then

learn and analyze the simulation results to identify the patterns and help in predicting the optimal well locations. A typical example of this was in the middle East with a clastic reservoir whereby a hybrid approach was used to predict the production performance of various well placement scenarios which resulted in over 15% improvement in the recovery of the field.

2.3.3.2 GEO-STATISTICS AND ARTIFICIAL NEURAL NETWORKS

In this type of hybrid, the geo-statistics models help to provide high-resolution maps of the reservoir properties while the ANN will predict production performance based on the provided maps. An example of this case was in west African field whereby a geo-statical analysis and ANN models were used to optimize infill drilling which help to produce the bypassed oil.

2.3.4 LIMITATIONS OF OPTIMIZATION TECHNIQUES

Despite their numerous advantages discussed above, optimization techniques have some limitations in their applications as follows:

- The accuracy of the result of the optimization technique applied depends on the quality and the availability of the input data
- Some optimization techniques need significant computational resources and a high level of expertise.
- There is a problem of geological and production uncertainties that can affect the reliability of model predictions.
- Implementation of advanced techniques usually involves high costs, so the incremental gain from infill drilling must overcome the drilling cost.

The optimization techniques discussed above are directly applicable to Toma South Oilfield. Toma South Oilfield fluvial-deltaic reservoirs require detailed characterization with advanced reservoir modelling to successfully identify their bypassed zones. There is a need for integration of seismic, well log and production to achieve accurate reservoir models. The economic analysis will be carried out and integrated into the optimization process so that the project grantee economically viability before implementation.

Optimization techniques for infill well placed have evolved mostly from the traditional reservoir simulation and geo-statistics to advanced machine learning and hybrid approaches that can provide a robust solution for addressing the complexities that arise in clastic reservoir [20]. Some of these techniques will be used in this study to optimize infill well placement in Toma South Oilfield to maximize recovery by identifying optimal infill well locations in a cost-effective manner.

2.4 APPLICATIONS AND LIMITATIONS OF OPTIMIZATION TECHNIQUES

The success of the optimization techniques in their application for infill well placement has revolutionized the oil and gas industry since most of these techniques integrate the geological, geophysical and production data which help to provide efficient, cost-effective solutions for well placement. These techniques as discussed earlier have some limitations despite their potential. This section will therefore examine the applicability of these optimization techniques in the clastic reservoirs while highlighting their limitations with much focus on their relevance to Toma South Oilfield. mentioned below are some of the examples where optimization techniques had been applied on clastic reservoirs.

2.4.1 ENHANCED IDENTIFICATION OF THE BYPASSED OIL

Applications of modern optimization methods like reservoir simulation and geo-statistical analysis have helped in precise targeting of unswept hydrocarbon zones in heterogeneous reservoirs. These methods work by integrating the geological and production data to map out the poorly drained areas that have bypassed oil hence infill wells are drilled in these high potential areas. Due to compartmentalization and heterogeneity in clastic reservoir, a good volume of hydrocarbons might be bypassed during the primary and secondary recovery. Reservoir simulation models can predict fluid flow paths while also identifying areas of bypassed oil. An example of this kind was in a fluvial-deltaic clastic reservoir whereby reservoir simulation was used to identify zone with bypassed oil near the shale barriers. An increase of about 15% was achieved due to the success of infill wells placement in this field.

2.4.2 OPTIMIZATION OF WELL SPACING

There is a need for determination of the optimal well spacing between the proposed infill wells and the existing wells in the field to minimize interference while also maximizing reservoir drainage. Geostatistical models and sensitivity analysis are used to design well spacing strategies that can balance recovery efficiency with operational costs. Clastic reservoirs that have high anisotropy with improper well spacing can lead to either uneven drainage of the reservoir or rapid water breakthrough. This technique was used in a South American clastic reservoir to optimize well spacing which resulted in over 10% increase in production efficiency.

2.4.3 PREDICTION OF WELL PERFORMANCE

Some machine learning techniques such as artificial neural networks (ANNs) are commonly used to predict the performance of proposed infill wells which are based on the historical production data and reservoir characteristics. The input variables like permeability, porosity, water saturation and well spacing are analyzed by the ANNs to predict the production rates of wells and recovery factors for the proposed well locations.

An example of this scenario is a west African sandstone reservoir whereby ANN model was used to predict production rates for much infill well locations to choose the best.

2.4.4 real-time decision making

Big data analytics and real-time monitoring tools have advantages of adjusting the well placement when new data becomes available. This is very important in reservoirs with constant dynamic production behavior like those clastic reservoirs with active water or gas drive mechanisms. Real-time data from sensor were used in North American Oilfield to reduce water breakthrough in a clastic reservoir to dynamically adjust well placement in the drilling phase.

2.4.5 COST-EFFECTIVE FIELD DEVELOPMENT

Integration of cost benefit analysis in the optimization process will first confirm whether drilling infill wells is economically viable before it becomes technically feasible [21]. Methods like Net present value analysis and internal rate of return on investment can be used to evaluate the profitability of the proposed infill wells drilling campaign. This is because mature clastic reservoirs like the one of Toma South usually have declining production rates hence economic evaluation is needed for them to grantee economic feasibility. Prior Economic feasibility that was done on Southeast Asian Clastic reservoir showed that drilling two infill wells in high-potential zones was good as it yields 30% of Internal Rate of Return (IRR).

It is therefore clear that optimization techniques discussed above are very effective in placement of infill wells in clastic reservoirs, but they have limitations in applications like geological uncertainty, computational complexity, data quality and the economic constraints due to the cost attached to it. Tailored approaches have been done to optimize the placement of infill well in Toma South with proven economic viability.

2.5 GAPS IN EXISTING RESEARCHS (gaps addressed in this study)

There are many knowledge and methodological gaps in the current studies on infill wells optimization especially on clastic reservoirs like the one of Toma South oilfield.

- There is a limited application of advanced optimization techniques in clastic reservoirs whereby techniques such as reservoir simulation and Artificial Neural Network (ANNs) and machine learning have been successfully applied in the types of reservoirs. This research will apply reservoir simulation in Toma South oilfield to optimize infill well placement.
- This research will try to bridge the gap between geological, production and economic data since the previous studies focused only on individual parts of the reservoir management like reservoir production performance and geological modelling. This research will therefore integrate geological, production and

economic data for developing a comprehensive optimization strategy for placement of infill wells. This is good for Toma South Oilfield whose operational budget for drilling infill wells is financially constrained.

- Most of existing research focused much on the areas that has developed oil and gas industries like the middle East, North America and Europe while Neglecting oilfields in developing countries like South Sudan. This research will therefore bridge the knowledge gaps by tailoring appropriate techniques that are specific to the geological and operational conditions of Toma South.
- Fluctuations in oil and gas prices globally may impact the economic viability of the proposed infill drilling program, so this research will simulate the performance of the infill wells at different oil prices to ensure the cost-benefit ratio analysis ensures positive return on this investment.

By dressing the above-mentioned Research gaps, this research therefore seeks to contribute to the global knowledge on infill well optimization that is more specific to Toma South oilfield according to its geological and reservoir conditions.

In summary, this chapter has discussed extensively the previous studies on infill well placement and the optimization techniques with emphasis on their relevance to the clastic reservoir like those of Toma South. It can be seen that a big progress has been made in applications of the techniques mentioned above in optimization of the infill wells. However, many challenges such as the geological complexity of the field like Toma South, data limitations and economic feasibility of the infill drilling program have posed difficulties in their application. The research gaps identified above made it reasonable to come up with this research that is more innovative and field-specific to Toma South oilfield. This research will also help to contribute to the body of knowledge on infill well placement in clastic reservoirs especially in Muglad Basin where Toma South Oilfield is located in.

3: METHODOLOGY

3.1 RESEARCH DESIGN

This research focuses on creating a comprehensive reservoir model for the Toma South Oilfield by integrating geological, geophysical, petrophysical, and reservoir engineering data. The chapter outlines a structured approach that involves several key stages: data gathering and preparation, static and dynamic model construction, history matching, and sensitivity analysis of the reservoir model. This partitioning facilitates the evaluation of reservoir behaviors and aids in identifying potential locations for infill wells. The research adopts a quantitative philosophy, employing numerical modeling and computational simulations through software tools such as T-navigator, Petrel, Eclipse, and Prosper. It aims to predict reservoir performance under varying conditions, following a problem-driven methodology tailored to the specific challenges faced in the Toma South Oilfield.

3.2 DATA PREPARATION AND INTEGRATION

3.2.1 Data Collection

The research utilizes data from the Toma South fully field review (FFR), focusing on several key categories. Geological data encompasses structural maps, fault interpretations, stratigraphic sequences, reservoir thickness, depositional environments, and facies distribution. Isopach maps accompanied by cross-sections highlight reservoir layers such as Bentiu and Aradeiba main sand.

Geophysical data includes a 3D seismic interpretation, comprising time and depth structural maps, and seismic inversion data that aids in predicting reservoir properties like porosity and lithology. Additionally, records of fault patterns and variance cube analysis were employed to discern the structural compartments of the reservoir.

Petrophysical data is derived from well logs of 18 existing drilled wells, along with core analysis reports evaluating permeability, porosity, and relative permeability. Critical metrics such as volume of shale, formation water saturation, and average cut-off parameters for net pay calculations were also documented.

Production data consists of historical production rates from current producing wells, cumulative oil production, and water cut trends. Important parameters like bottomhole flowing pressures (BHP), static fluid level (SFL), and dynamic fluid level (DFL) have been recorded, alongside the artificial lift parameters for wells, including the intake depth of the pumps.

Lastly, fluid and reservoir properties were characterized through PVT analysis of oil, gas, and water samples. Additional data on rock compressibility, water compressibility, oil viscosity, aquifer parameters, and historical pressure insights are included for comprehensive material balance analysis.

3.2.2 DATA VALIDATION AND QUALITY CONTROL

The data from the Toma South Oilfield underwent a comprehensive quality control (QC) process to ensure accuracy, consistency, and reliability, critical for minimizing errors in simulation outcomes. The validation process encompassed several key steps:

1. Verification of well logs was conducted, rectifying discrepancies by correlating them with a fixed datum point. This alignment facilitated uniformity for geological and petrophysical analyses across all wells.
2. The seismic inversion results were validated against well logs data to confirm the consistency of predicted rock properties such as porosity and lithology. Additionally, seismic time maps were aligned with depth-converted structural maps to ensure coherent data integration.
3. Core-derived permeability and porosity values were systematically compared with log-derived estimates to verify their equivalency. PVT data, including bubble point pressure and formation volume factor, were matched against regional field analogs to ensure their reliability.
4. Production data from existing wells was meticulously validated by comparing historical production data with formation tester trends, allowing for the identification of inconsistencies. Furthermore, the results from field production back-allocation were reconciled with well test results to affirm their validity.

3.3 GEOLOGICAL MODEL CONSTRUCTION

The validated data was integrated into a unified reservoir model framework by combining static and dynamic data for enhanced accuracy. Seismic interpretation data was utilized within Petrel software to create a structural framework. Concurrently, well tops, isopach maps, and facies distribution were incorporated to construct a comprehensive 3D geological model. The distribution of porosity and permeability was generated via sequential Gaussian simulation, constrained by well log data and seismic inversion results. Additional petrophysical properties, including Net-To-Gross ratio, water saturation, and shale volume, were also integrated into the model. Calibration of the geological model was performed using historical production rates and dynamic data like reservoir pressure trends. Furthermore, PVT data and fluid properties were incorporated to characterize reservoir fluid behavior. Initial conditions such as reservoir pressure, fluid contacts, and saturation profiles were assigned to finalize the model. A simulation grid was established, and geological properties were upscaled accordingly into this grid to prepare for simulation.

3.4 RESERVOIR SIMULATION MODEL

This section will outline the steps that are involved, from building the model, initializing it and calibrating it. The static and dynamic reservoir data were integrated for

representation of reservoir behavior to predict the future performance of the field under different operating conditions.

3.4.1 MODEL CONSTRUCTION

The construction of the simulation model involves constructing a grid-based 3D representation of the Toma South Oilfield.

3.4.1.1 GRID DESIGN

Below is the grid design of the model

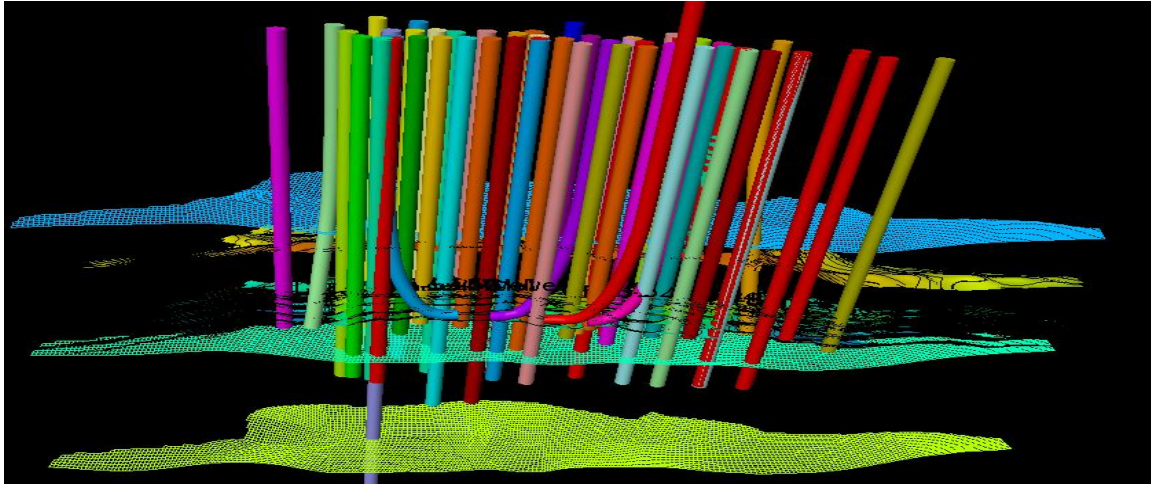


Fig. 1: grid of the model (Source: Author's own analysis.)

3.4.1.2 RESERVOIR LAYERS

The model created partitioned the reservoir into multiple layers based on their depositional environments and their characteristics. 2 distinct formations can be seen namely Bentiu formation having its own sublayers like 1A, AB, 1C, 1D and Bentiu 2A. The other formation is Aradeiba main sand.

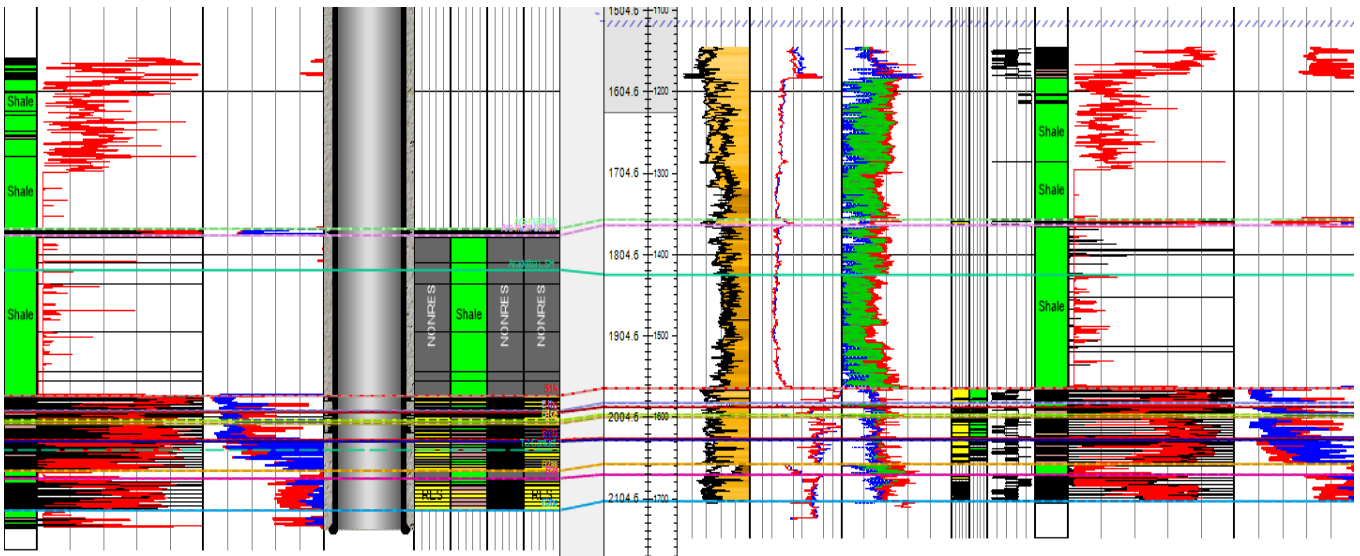


Fig. 2: reservoir layers (source: Author's own interpretation of Toma South Logs)

3.4.1.3 FAULT REPRESENTATION

Below are the faults identified

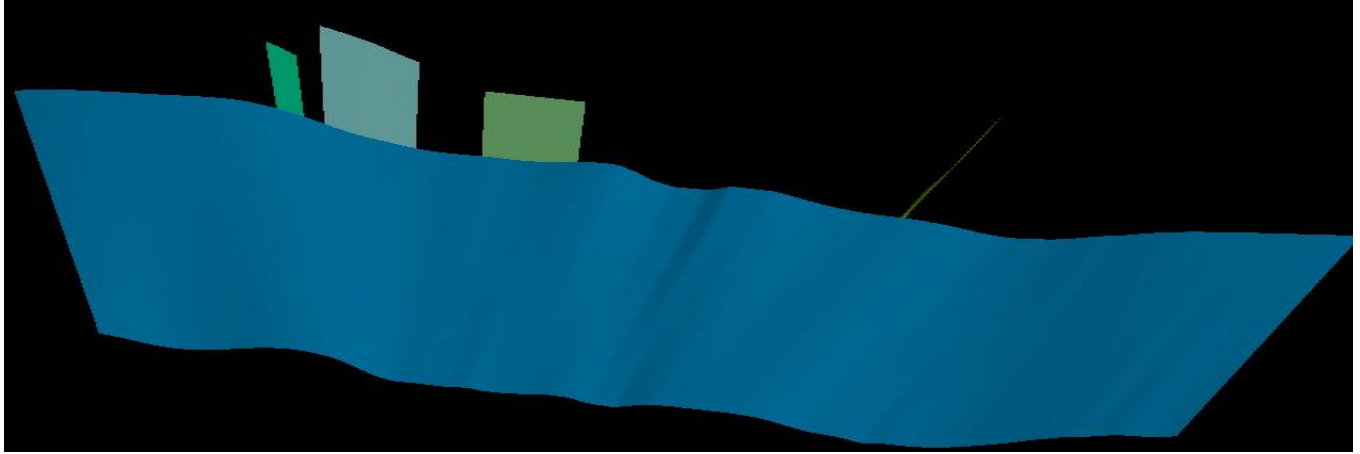


Fig. 3: faults identified (source: Author's reservoir simulation analysis)

The simulation model was then initialized after incorporating initial conditions, fluid saturation, fluid contacts, fluid properties, rock properties and pressure trends. The reservoir has exhibits aquifer support so aquifer modelling using Carter-Tracy Aquifer model was used. The aquifer model was then validated against historical pressure trends and water cut data. History matching was then done to replicate the observed performance in the future.

The model was checked with the independent estimates that was done for STOIIP comparison and production trend validation. The final reservoir simulation model was able to provide the pressure profile, saturation profile and production rates profile for each reservoir layer. The model was able to forecast the future production profile while also identifying the bypassed oil zones.

3.5 OPTIMIZATION OF INFILL WELLS

The optimization process of infill well has been designed to be guided by a well-defined objective function that will integrate technical, economic and operational feasibility. The primary goal of this optimization process is to maximize recovery factors of the field, enhance the economic viability of the project and operational feasibility.\

3.5.1 SCENARIO DESIGN

Multiple design scenarios have been developed to evaluate the impact of various well strategies aimed at testing and validating a simulation model in oil recovery. Each scenario incorporates distinct variables such as location, well trajectory, and completion strategies.

1. Base Case (Do Nothing Case): In this scenario, no new wells are drilled, and existing

wells continue production until they reach an economic limit marked by a 99% water cut. This serves as a benchmark for comparison against other strategies.

2. Artificial Lift Case: This scenario explores the potential of increasing oil recovery by optimizing artificial lift methods like the electrical submersible pump (ESP). Adjustments to parameters such as the pump's intake depth were tested; however, results were disappointing due to poor reservoir deliverability and significant amounts of bypassed oil remaining in the reservoir.

3. Infill Well Case: This scenario focuses on drilling new infill wells aimed at tapping into the bypassed oil not accessed by existing wells. The study examines various well types, including conventional vertical wells aimed at specific reservoirs, as well as directional and horizontal wells designed to reach reservoirs that are otherwise difficult to access. This case represents the primary objective of the research, with multiple techniques applied to enhance oil recovery from bypassed zones.

4. Well Completion Strategies: This scenario assesses whether to employ commingled production from identified reservoirs or to isolate each zone using packers or other isolation techniques (إتمام بئر, n.d.). The findings indicate that neither approach yielded significant results, primarily due to the pressure differentials between the reservoirs hampering the production of bypassed oil zones, regardless of the method used for completion.

The various scenarios thus highlight the complexities and challenges involved in optimizing oil recovery strategies while illustrating the importance of targeted well drilling and completion techniques to improve overall production efficiency.

3.5.2 SENSITIVITY ANALYSIS

Sensitivity analysis was conducted on several parameters that have an impact on infill well performance as discussed below.

Well spacing was analyzed to determine its impact on the recovery factor. Sensitivity was done well spacing scenarios such as 500m and 1000m. saturation maps and simulation results were used to identify areas with remaining oil saturation. The artificial lift parameters such as the number of stages, frequencies and intake depths were evaluated to determine their effect on the overall field performance. Water cut limits were assessed from 93% to 99% on the economic viability of the infill well drilling.

3.5.3 PERFORMANCE METRICS

Each infill well scenario was evaluated using quantitative metrics to assess their performance. Cumulative oil production, expressed as Estimated Ultimate Recovery (EUR), measures the total oil volume produced throughout the economic lifespan of the field. The recovery factor (RF) indicates the percentage of Original Oil in Place (OOIP) that is recovered for each reservoir unit and the entire field (Ms & Ms, 2024). A crucial metric in this research is the Net Present Value (NPV), which reflects the present value of the cash flow generated by each scenario, factoring in costs and revenues. Additionally,

the Internal Rate of Return (IRR) and payback period are highlighted as important metrics. The water cut, which indicates reservoir depletion, is monitored to determine when the field reaches the abandonment stage.

3.6 ECONOMIC ANALYSIS

The economic analysis aimed to assess the financial performance of various infill well scenarios by analyzing costs and revenues, ultimately identifying the most economically viable development plan. It included a risk-based evaluation of investment decisions while accounting for uncertainties in economic and technical parameters. The analysis began by defining the base case and alternative development scenarios, each associated with estimates for capital expenditure (CAPEX) and operating expenditure (OPEX). Annual cash flow was computed by deducting CAPEX and OPEX from revenues generated through oil and gas sales, factoring in taxation and government royalties.

A sensitivity analysis was conducted to evaluate the impact of different scenarios, followed by a Monte Carlo simulation for risk analysis to account for uncertainties in costs, production, and price forecasts. This led to the generation of probability distributions for net present value (NPV), internal rate of return (IRR), and payback periods, assessing the risk profile of each scenario (Fiveable, 2025). The economic decisions were based on incremental benefits from infill wells, cost efficiency, and the overall economic viability of the project. By combining technical and economic analyses, the methodology aimed to select infill well strategies designed to maximize the recovery factor in the Toma South Oilfield.

3.7 SUMMARY

This methodology offers a structured framework for optimizing the placement of infill wells in the Toma South Oilfield. It integrates geological modeling, reservoir simulation, and economic analysis to enhance hydrocarbon recovery while maintaining operational and financial efficiency. The approach successfully delivers a well-calibrated reservoir simulation model tailored for the Toma South Oilfield, fulfilling its objectives effectively.

4: RESULTS AND DISCUSSIONS

The research findings are structured to emphasize the results from model validation, production forecasts, scenario analysis, and economic evaluation. The outcomes indicate how various infill well configurations and strategies affect recovery factors, production performance, and financial metrics.

4.1 MODEL VALIDATION RESULTS

The reservoir simulation model underwent validation via history matching to confirm its accuracy in replicating observed reservoir behavior and production performance. Key validation metrics included reservoir pressure, water cut trends, and cumulative production.

4.1.1 RESERVOIR PRESSURE MATCHING

Reservoir pressure serves as a critical parameter for validating simulation models, reflecting the dynamic equilibrium among production, aquifer support, and fluid flow. The simulation results for reservoir pressure were compared with observed static pressure data from RFT, FMT, and static gradient survey (SGS). Key findings indicate that the simulated field-average reservoir pressure closely matches historical data, with an average deviation of less than 5%. The static reservoir pressure in the Bentiu formation started at 2890 Psi in 1999 and declined to 1395 Psi by July 2025, consistent with historical trends.



Fig. 4: field pressure from the start of production (source: Author's reservoir pressure analysis)

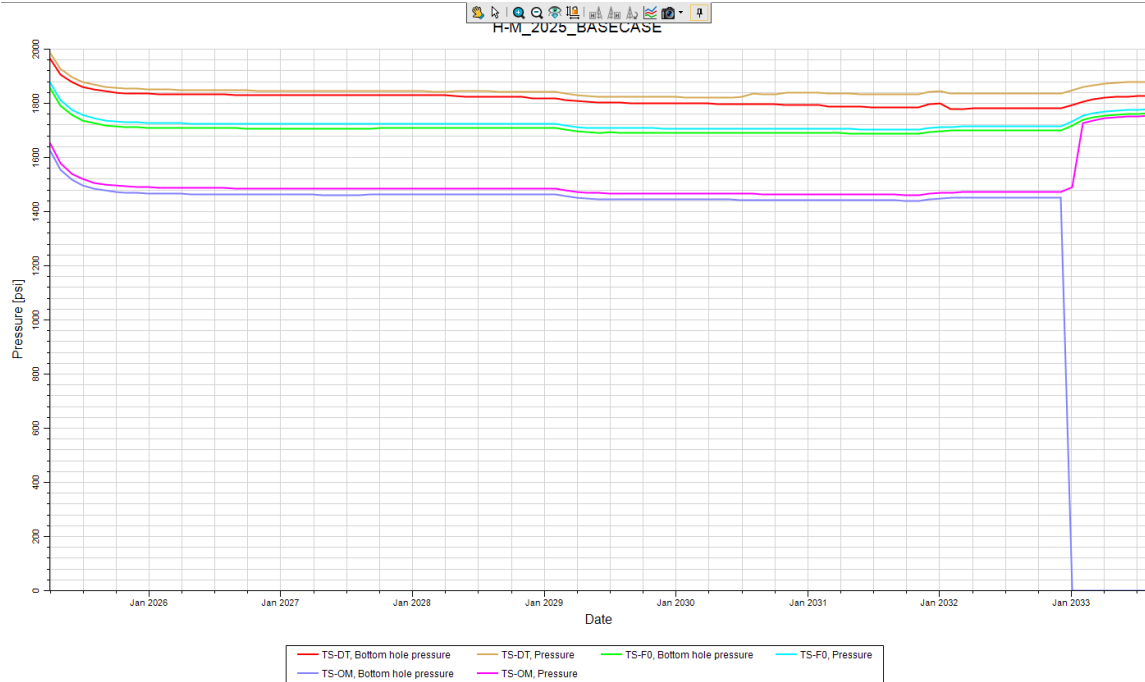


Fig. 5: simulated Vs observed pressure trends for the Bentiu formation showing a strong correlation. (Source: Author's comparison of simulated vs observed pressure)

At a well-level pressure match, it was observed that the well pressures for the individual wells such as TS-DT, FO and TS-OM were accurately captured in the simulation with a deviation of less than 10 Psi

Table 1: observed and simulated pressures for the selected wells confirming the consistency across the field (source: Author's comparison of 2 selected wells)

Well Name	Simulated pressure	Observed pressure
TS-IK	738.444	688.970
	696.954	646.851
TS-MJ	1693.766	1643.506
	1661.052	1611.095
	1642.248	1592.113

It was observed that the Carter-Tracy aquifer model effectively simulated water influx from the edge and bottom which helps in maintain pressure support in Bentiu formation. The wells that were located near the structural edges showed pressure depletion that was more prominent due to limited aquifer support in these regions coupled with the problem of higher water production. example of such wells includes TS-IK and TS-CK.

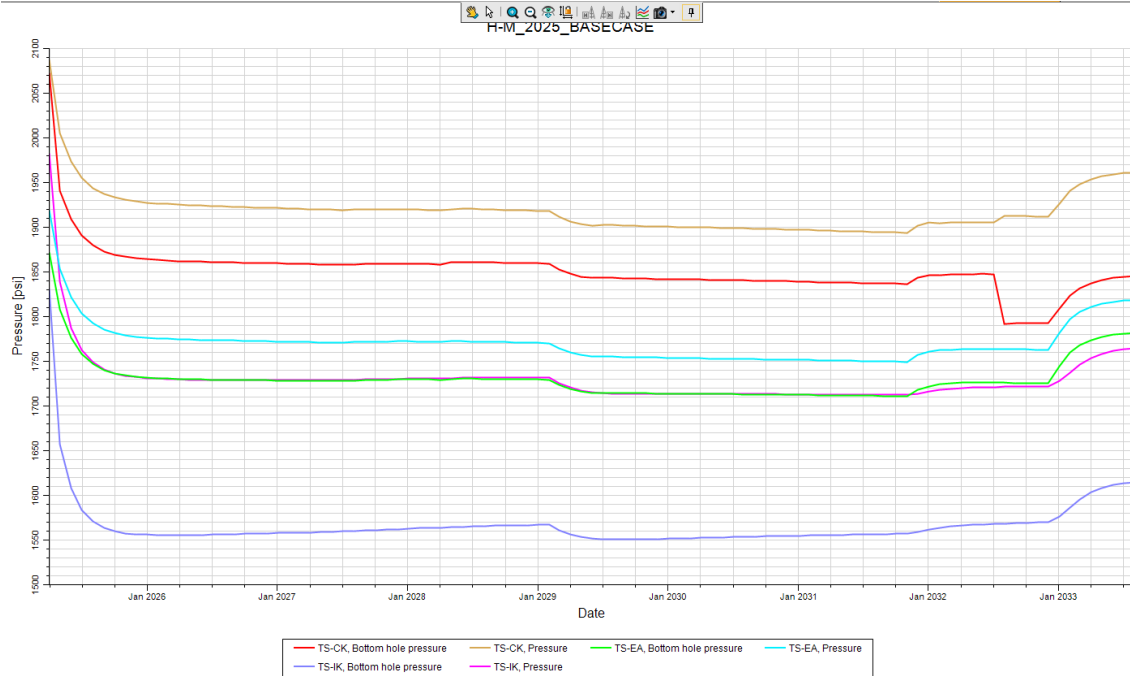


Fig. 6: simulated vs observed pressure trends (Source: Author's comparison of simulated vs observed pressure for some wells)

4.1.2 WATER CUT MATCHING

The trend of water cut is an essential indicator of reservoir depletion and fluid movement within an aquifer. The alignment of simulated water cut with historical data is crucial for accurately modeling aquifer behavior and understanding reservoir heterogeneity. Notable findings include a significant increase in the simulated field average water cut from 0% at the beginning of production in 1999 to 62.8% by December 2006, correlating with historical production metrics. Furthermore, wells positioned at structural highs, such as TS-EA and FO, demonstrated a slower rise in water cut due to enhanced reservoir drainage associated with their higher production rates.

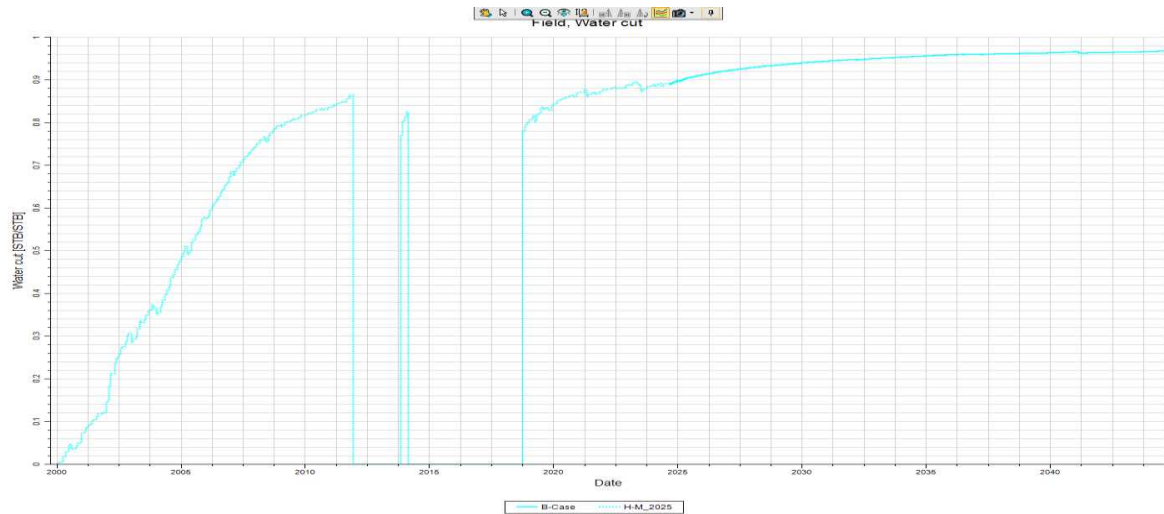


Fig. 7: field-wide simulated vs observed water cut trends (Source: Author's comparison of simulated vs observed water-cut)

At the well level, the simulated water cut for individual wells closely aligned with field data, demonstrating a deviation within 3% for the majority. Notably, wells situated near the aquifer's edge or fault zones, such as TS-MJ and TS-IK, displayed higher water cuts exceeding 80% during the initial production phase. The model effectively captured the effects of reservoir heterogeneity and fault transmissibility on the progression of water cuts. Additionally, wells experiencing elevated water cuts exhibited a marked decrease in productivity, underscoring the necessity for water shut-off interventions in these cases.

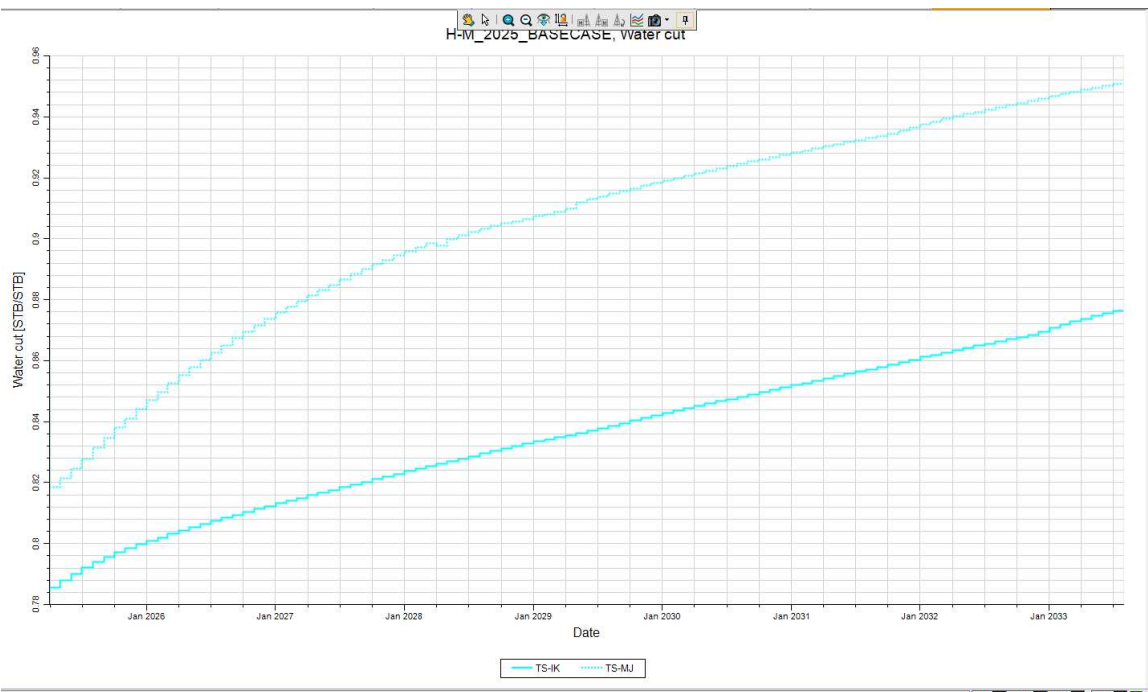


Fig. 8: wells level water cut trends for some selected producers (Source: Author's own analysis)

4.1.3 CUMULATIVE OIL PRODUCTION MATCHING

Cumulative oil production serves as a crucial metric for validating a model's performance in replicating field production. By March 2006, the model simulated a cumulative oil production of 163.230 million stock tank barrels (MMstb), closely aligning with the observed cumulative production of 167.940 MMstb. The model indicates a plateau production phase from 2003 to 2006, followed by a gradual decline attributed to increasing water cut. At the well level, most wells showed cumulative production within 5% of observed values, with high-producing wells like TS-EA and FO demonstrating a strong correlation between simulated and actual production due to their favorable structural positioning in the reservoir.

Table 2: comparison of simulated and observed cumulative production for some selected wells (Source: Author's comparison of simulated vs observed cumulative oil production)

H-M_2025_BASECASE, Oil production cumulative	Column1	Column2
X	Y1	Y2
Date	TS-EA	TS-FO
	Oil production cumulative [STB]	Oil production cumulative [STB]
04-01-2025	29622514	18678174
05-01-2025	29653146	18710450
06-01-2025	29683828	18741168
07-01-2025	29713128	18769826
08-01-2025	29743090	18798676
09-01-2025	29772746	18826888
10-01-2025	29801146	18853648
11-01-2025	29830184	18880780
12-01-2025	29857984	18906556
01-01-2026	29886448	18932790
02-01-2026	29914646	18958652
03-01-2026	29939906	18981718
04-01-2026	29967618	19006924
05-01-2026	29994208	19031020

Well name	Simulated results	Observed results
TS-EA	30126348	30129469
	30152444	30183537
	30177488	30196594
TS-FO	30203152	30215273
	30228602	30249715

According to the observations, the model effectively incorporates contributions from individual reservoir layers, including Bentiu 1A, 1B, 1C, 1D, and 2A, into the total

cumulative production. Additionally, the simulation identified zones with bypassed oil, facilitating the strategic placement of infill wells in these areas.

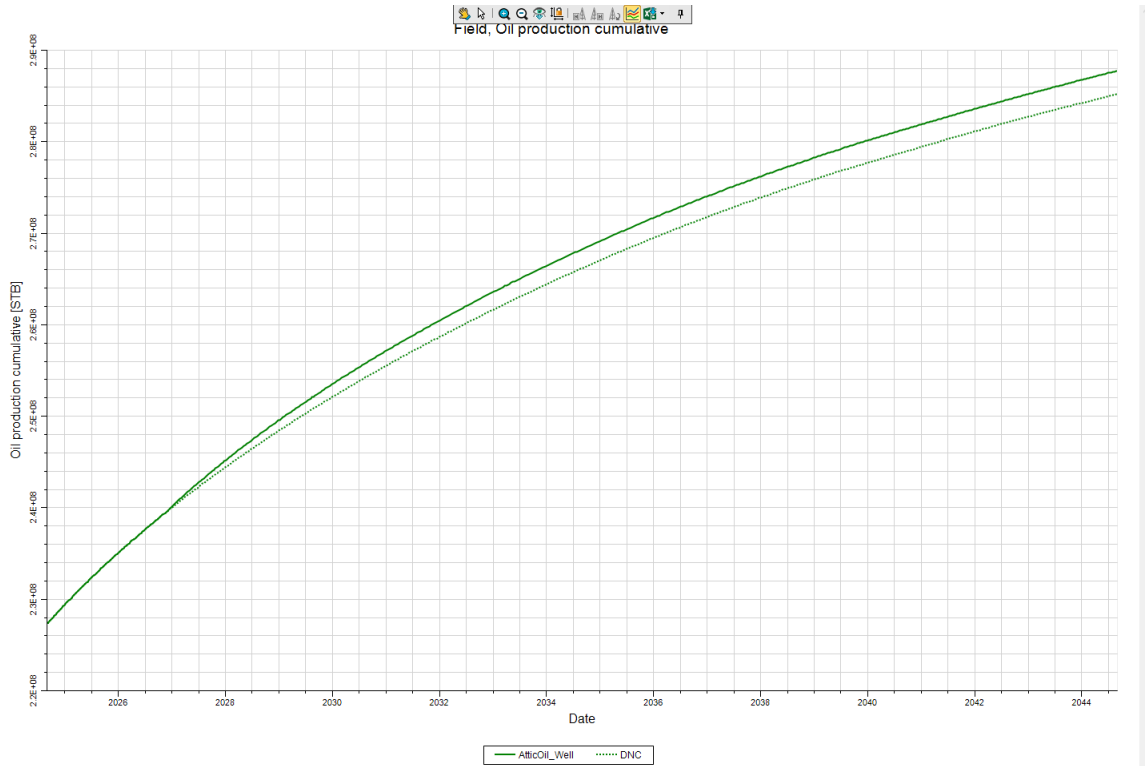


Fig. 9: simulated vs. observed cumulative oil production at field level (Source: Author's comparison of simulated vs observed cumulative oil production)

4.1.4 VALIDATION OF AQUIFER MODELS

Historical pressure trends and material balance results were utilized to validate the aquifer model developed using the Carter-Tracy analytical model. The model successfully simulated water influx volumes and their effects on reservoir pressure. By March 2006, cumulative water influx was approximately 176 million stock tank barrels (MMstb), aligning with prior material balance estimates. The model demonstrated significant pressure support in the central regions of the field, while weaker support was identified at the structural edges. Additionally, it effectively illustrated both edge and bottom water influx in the Bentiu formation and indicated limited aquifer connectivity with weaker pressure support in the Aradeiba main sand.

4.1.5 SATURATION DISTRIBUTION VALIDATION

The validation of the saturation maps utilized well log data and production profiles, revealing the current location of oil-water contact and the distribution of remaining oil saturation (ROS). Key findings indicated that remaining oil manifested in simulation as undrained areas adjacent to faults and structural highs, corroborating production data.

Furthermore, the saturation maps identified bypassed oil in Bentiu 2A and Aradeiba main sand, presenting a favorable opportunity for the placement of infill wells.

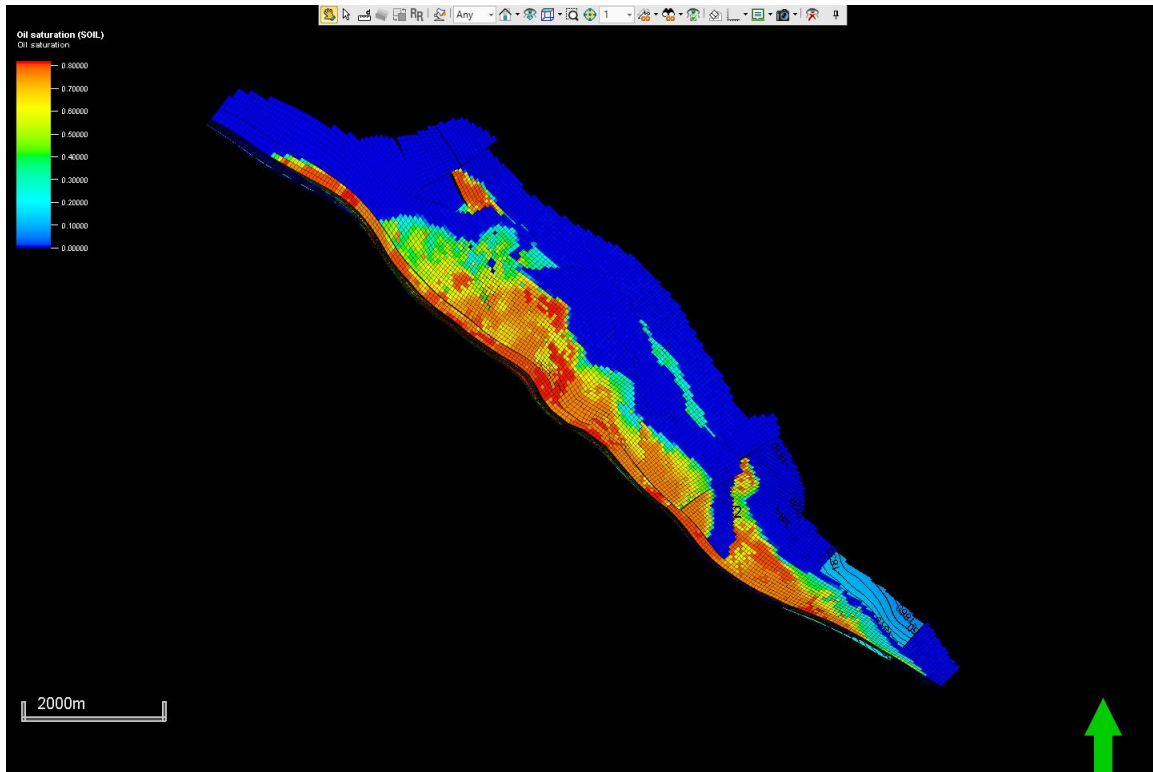


Fig. 10: simulation showing remaining oil map for Bentiu 2A (*Source: Author's reservoir simulation analysis*)

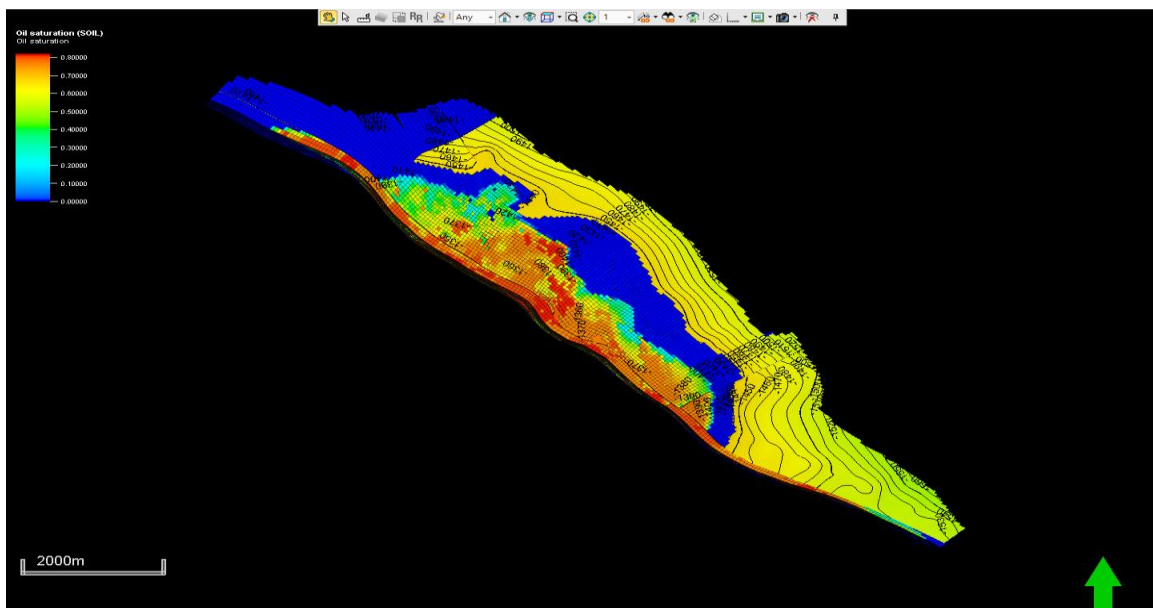


Fig. 11: simulation showing remaining oil map for Aradeiba main sand (Source: Author's reservoir simulation analysis)

In summary, the study resulted in a highly accurate reservoir simulation model for the Toma South oilfield, effectively replicating historical reservoir pressures, water cut progression, and cumulative production. The model successfully simulated aquifer behavior and water influx volumes. Additionally, it facilitated the identification of bypassed oil zones and high-ROS areas for potential infill well placement.

4.2 PRODUCTION FORECASTS

The validated reservoir simulation model was used for production forecast for “do nothing case” (base case) as well as other optimized development scenarios involving infill wells, workovers and other increased liquid lift cases. The forecasts made include full detailed predictions of oil, water and gas production rates, cumulative oil production, recovery factors for all scenarios and the water cut progression.

4.2.1 BASE CASE (“DO NOTHING”)

The base case analysis for the Toma South oilfield assumes no new well drilling, relying on 27 existing producers until the economic limit is reached, defined as a 99% water cut. The average oil production rate is projected to decline due to reservoir depletion and increased water cut, forecasting a drop to 3843 stb/d by the end of 2019, with total cumulative production reaching 277.90 MMstb. By 2028, cumulative production is expected to reach 299.02 MMstb, achieving a recovery factor of 50.2%.

Water cut is forecasted to rise sharply from 62.8% to 96.9% by 2029 and further to 98% by 2033, with wells near structural edges (TS-CK, TS-IK) experiencing higher water cuts earlier than those near structural highs (TS-EA, FO). A production plateau was maintained from 2003 to 2006, after which declines began due to reservoir pressure depletion and increased water output. The strong aquifer support in Bentiu reservoirs contributed to slower pressure depletion but accelerated water production, particularly in edge wells. The base case emphasizes the risks of bypassed oil in undrained regions, highlighting the need for infill wells to enhance oil recovery.

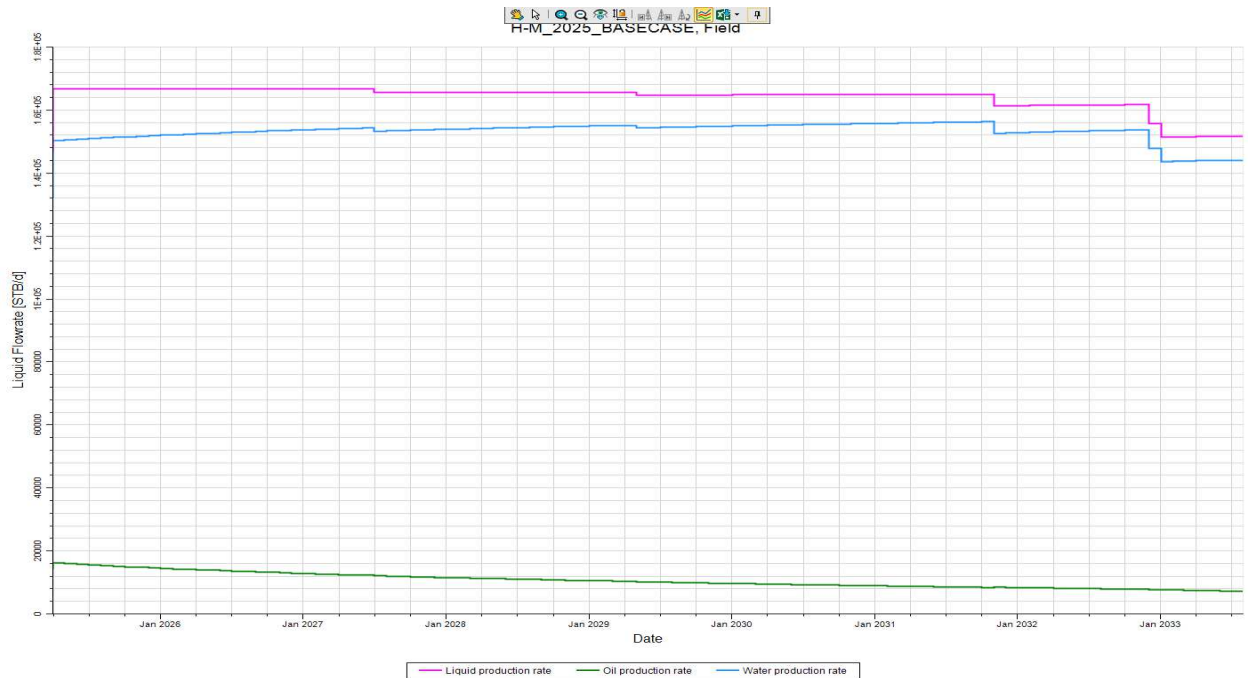


Fig. 12: Base case production forecast for oil, water and total *liquids* (Source: Author's reservoir simulation analysis)

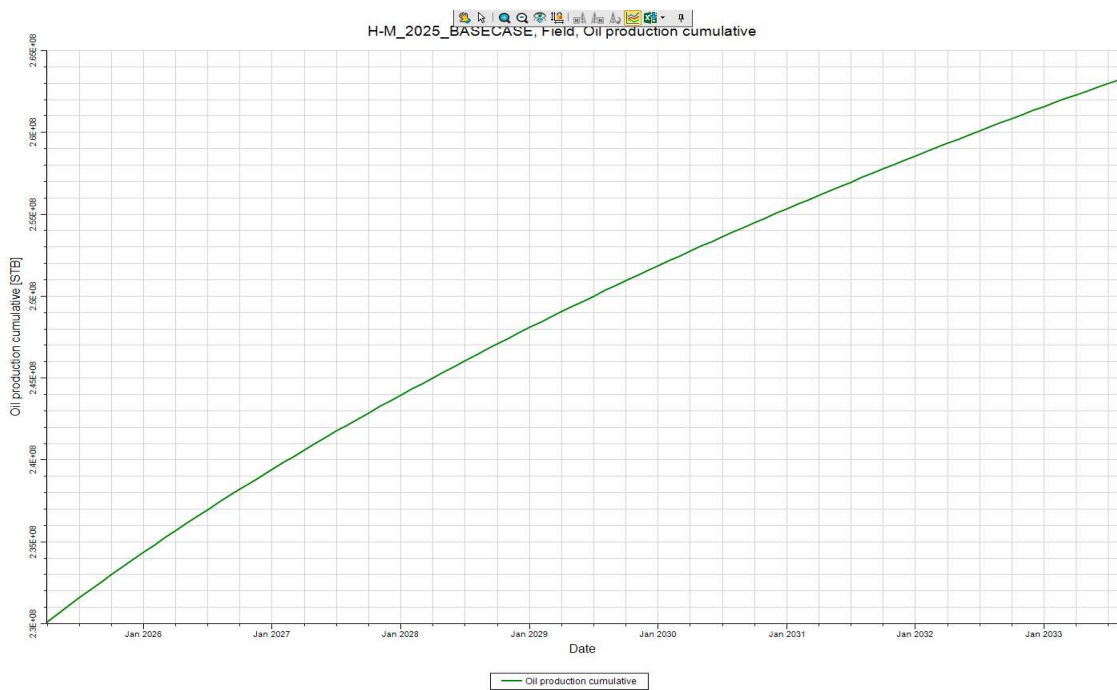


Fig 13: Base case field-level production metric from 2025 to 2033 (Source: Author's reservoir simulation analysis)

4.2.2 INFILL WELL SCENARIOS

Several scenarios were tested like vertical wells, horizontal and directional wells to evaluate the potential impact of infill drilling placement. These multiple scenarios were aimed at increasing recovery by targeting by-passed oil zones and improving reservoir drainage.

4.2.2.1 VERTICAL INFILL WELLS

Four vertical wells were drilled in high potential zones, targeting Bentiu 1A and Bentiu 1D. The recovery factor improved by 3.5%, reaching 52.1% in 2025 and approximately 53.8% by the end of 2027. Cumulative oil production increased to 293.50 MMstb by 2025 and 301.77 MMstb by 2030, with a slightly higher water cut than the base case due to production from water-out zones.

Vertical wells proved to be cost-effective and suitable for thicker reservoir intervals but showed limited drainage efficiency in thin or heterogeneous layers like Toma South.

4.2.2.2 HORIZONTAL INFILL WELLS

Six horizontal wells were drilled, targeting the Bentiu 2A and Aradeiba main sand to enhance the contact with thin, underdeveloped reservoirs. This approach led to a recovery factor increase of approximately 4.8%, reaching 53.2% by 2025 and 54.9% by 2028. The cumulative oil production is projected to increase to 303.57 million stock tank barrels (MMstb) by 2025 and to 311.89 MMstb by the end of 2030. Notably, the water cut was found to be lower than in the base case, attributed to improved reservoir drainage and delayed water breakthrough. The scenario illustrates the highest incremental recovery potential, particularly in thin, stratified reservoirs with restricted vertical permeability.

4.2.2.3 DIRECTIONAL INFILL WELLS

In this case scenario, five directional wells were drilled to target bypassed oil near faults and structural edges, covering multiple reservoir layers. The results indicated an improvement in the recovery factor of approximately 4.2%, reaching around 52.0% by 2025 and 53.8% by the end of 2028.

Cumulative oil production rose from 293.66 million stock tank barrels (MMstb) by the end of 2025 to 299.96 MMstb by 2028. Although there was no significant change in water cut results compared to the base case, earlier water breakthroughs were noted in fault-adjacent wells. This case highlights the effectiveness of directional wells in fault-dominated areas, though advanced geo-steering is necessary for successful drilling execution.

Fig. 15: incremental oil recovery for infill well scenarios (Source: Author's reservoir simulation analysis)

4.2.3 LIFT LIQUID CASE

This scenario assessed the enhancement of production through increased liquid lifting capacity using existing wells via ESP optimization. It resulted in an incremental recovery factor improvement of 2.7%, achieving 50.1% in 2019 and projected to reach 51.8% by 2025. Cumulative oil production is expected to rise from 304.28 million stock tank barrels (MMstb) in 2025 to 306.98 MMstb by 2028.

However, water cuts are anticipated to increase from 96.8% in 2019 to 98.3% by 2025 due to higher water production from edge wells. While increasing liquid production can extend the production plateau, it also accelerates the progression of water cut in high-water cut wells, making this approach less cost-effective compared to infill drilling due to high operational costs associated with water handling, treatment, and disposal.

4.2.4 SCENARIO SENSITIVITY ANALYSIS

A sensitivity analysis was done to evaluate the impact of some key parameters on production forecasts, and the following were some key findings.

The optimal spacing of 750m between infill wells has proven to minimize interference during production and will also maximize the recovery.

for horizontal well, a lateral section of up to 400m do provides the best balance between the drilling cost and the reservoir contact.

Reducing the water cut limit to 98% instead of 99% reduces the total produced fluid but also very good economically as it reduces produced water handling costs.

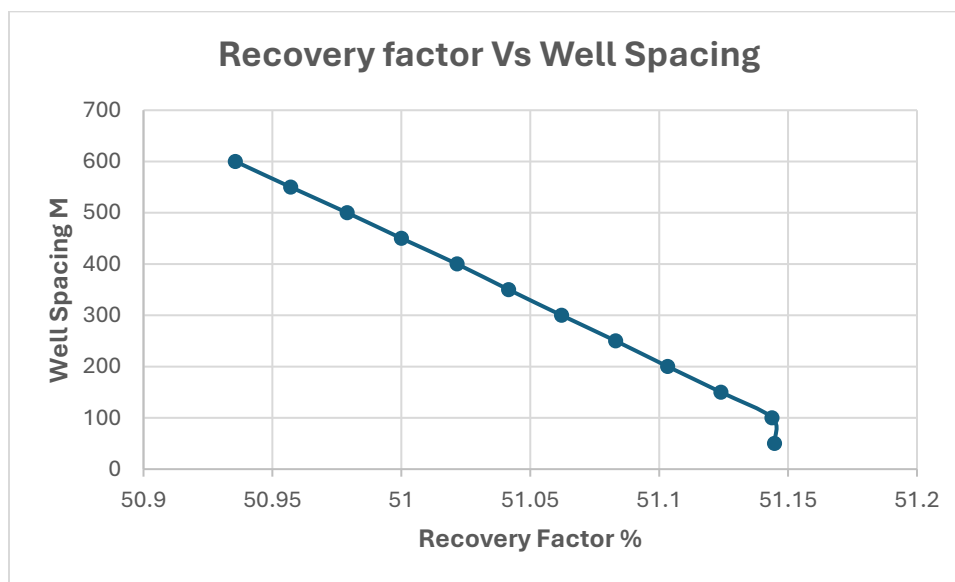


Fig. 16: sensitivity of recovery factor to well spacing for horizontal wells (Source: Author's own analysis)

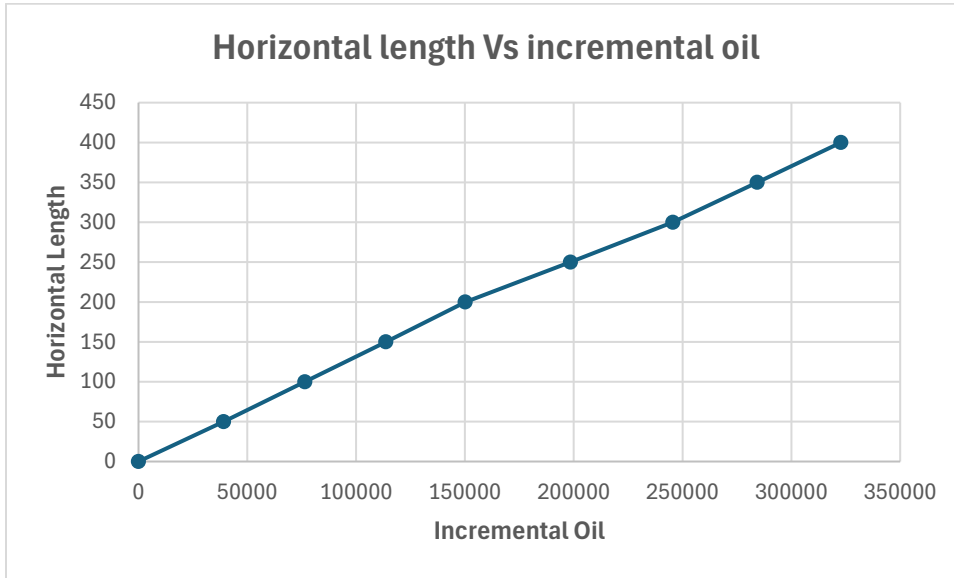


Fig. 17: impact of horizontal section length on incremental production wells (Source: Author's own analysis)

In summary, horizontal wells have been proven to outperform vertical wells in terms of recovery and economic performance especially in thine heterogeneous reservoirs. The big challenge with horizontal wells is their cost of drilling which is higher than the vertical wells. infill drilling in this field was able to target the bypassed oil in Bentiu 2A and Aradeiba main sand which gave a good incremental recovery.

4.3 SCENARIO COMPARISON

The results of the scenario analysis of the cases discussed above have been summarized in the table below.

Table 3: results of scenario comparison (source: Author's scenario analysis)

scenario	Cumulative oil (MMstb, 2025)	RF (%)	Water Cut	Incremental Oil (MMstb)
Base Case	280.90	48.4	96.9	-
Vertical Well	293.50	52.1	97.3	+ 13.9
Horizontal Well	303.57	53.2	97.2	+ 17.3
Directional Well	296.66	52.0	97.2	+ 13.4
Liquid Lift	288.28	50.1	96.8	+ 6.4

4.4 ECONOMIC EVALUATION RESULTS

The economic evaluation of Toma South Oilfield was conducted to assess the financial viability of various development scenarios. Key economic metrics used in the analysis include Net Present Value (NPV), Internal Rate of Return (IRR), payback period, and unit technical cost.

The evaluation permits comparisons of profitability, risk, and efficiency among scenarios, aiding in decision-making for field development. NPV reflects total discounted cash flow over the project's lifetime, with a positive value indicating a profitable investment; a discount rate of 10% was applied, typical for the region. IRR represents the rate at which NPV equals zero, providing insights into investment return rates.

The payback period denotes the time required to recuperate the initial capital outlay. Additionally, unit technical cost, calculated as total costs divided by cumulative production, measures cost efficiency per barrel produced. The break-even oil price represents the minimum price required for the project to yield profits.

4.4.1 BASE CASE ("DO NOTHING")

In the base case scenario, no additional wells were drilled, resulting in production solely from existing wells. The key findings indicated a Net Present Value (NPV) of \$144.53 million at a 10% discount rate, with no internal rate of return (IRR) or payback period due to the absence of new investments and upfront capital expenditures. The unit technical cost was calculated at \$23.75 per barrel, while the break-even oil price was determined to be \$28 per barrel.

The positive NPV stems from ongoing production without drilling or completion costs. However, the recovery factor was constrained to 50.2%, indicating substantial bypassed oil remaining in the reservoir. This base case will serve as a foundation for assessing the benefits of optimized development strategies.

4.4.2 INFILL DRILLING SCENARIOS

4.4.2.1 VERTICAL WELLS

Four vertical wells were drilled in this case to target bypassed oil in thicker reservoir zones like Bentiu 1A and Bentiu 1D.

The key results were that NPV was found to be \$173.95 million, IRR at 21%, payback period at 4 years, UTC was found to be \$19.95 per barrel while the break-even oil price was \$33 per barrel. The observation made was that vertical wells provide a moderate improvement in recovery and profitability while also benefiting from their low drilling and completion costs compared to others. Vertical wells are the most effective in simple zones with thicker reservoirs intervals but are less efficient in draining thin or heterogeneous reservoirs.

4.4.2.2 HORIZONTAL WELLS

Six horizontal wells were drilled in this case to maximize reservoir contact in thin and heterogeneous layers such as Bentiu 2A and Aradeiba Main Sand. The result was that the

NPV turned out to be \$215 million, IRR at 29%, payback period at 2.5 years, the UTC \$17.80 per barrel while the break-even oil price stands at \$30 per barrel. It has been observed that the horizontal wells significantly perform better than the vertical wells in terms of recovery and economic performance. Their higher initial cost is covered by increased oil production and delayed water breakthrough, giving it the overall best performance amongst all other available scenarios.

4.4.2.3 DIRECTIONAL WELLS

Five directional wells were drilled in this case to target bypassed oil near the faults and structural edges hence accessing multiple reservoir layers. The result was that the NPV turned out to be \$207, IRR at 25%, payback period was 3 years, UTC at \$18.55 per barrel while the break-even oil price was \$31 per barrel. Although it was observed that the directional wells offer a good balance between cost and recovery, especially in complex areas, they usually require precise geo-steering to avoid drilling into non-productive zones.

4.4.3 LIFT LIQUID OPTIMIZATION SCENARIO

The result for artificial lift optimization is that NPV turned out to be \$149.24 million, IRR at 16%, payback period as 5 years, UTC at \$21.35 per barrel while the break-even oil price turned out to be \$35 per barrel. It has been observed that optimizing liquid lifting capacity by adjusting ESP settings provides moderate economic benefits but is less profitable when compared to the infill drilling due to the high operational costs involved in handling the increased produced water. This scenario best suits extending the life of the existing wells than maximizing recovery.

4.4.4 COMPARISON OF THE ECONOMIC EVALUATION SCENARIOS

Below is the summary of results of the economic evaluation as summarized in the table below

Table 4: comparison of the economic evaluation scenarios (Source: Author's own analysis)

Scenario	NPV (\$M)	IRR (%)	Payback period (years)	UTC (\$/barrel)	Break-even oil price (\$/barrel)
Base case	144.53	19	3	23.75	28
Vertical wells	173.95	21	4	19.95	33
Horizontal wells	215.46	29	2.5	17.80	30
Directional wells	207.14	25	3	18.55	31
Lift Liquid case	149.24	16	5	21.35	35

4.4.5 SENSITIVITY ANALYSIS RESULTS

Various sensitivities analysis was undertaken for key variables as discussed below to assess their impact on economic performance

- Oil price sensitivity

The sensitivity analysis showed that horizontal wells remained profitable even at oil prices that are low as \$50 per barrel while the lift liquid scenario becomes uneconomical at prices below \$55 per barrel.

- Drilling and completion costs

It has been observed that a 10% increase in the drilling costs reduce the NPV of horizontal wells by around \$20 million, but this does not actually affect their ranking as the most profitable option available compared to others.

- Recovery factor

The higher recovery factor in horizontal wells is due to their longer later section which gives it longer contact times with the reservoir which makes it contribute significantly to their economic performance.

5.0 LIMITATIONS AND UNCERTAINTIES

These results have provided a valuable insight into this study; however certain limitations and limitations have been acknowledged.

Reservoir and simulation uncertainties: the reservoir model developed and used was based on the geological and production data available, however uncertainties in reservoir properties may have effect on the accuracy of the forecast.

Economic assumptions: the forecast assumes a base oil price and stable drilling price which may change with time.

Implementation risks: there are some risks like drilling challenges which may occur

In summary, this economic evaluation has highlighted the following key findings

1. Horizontal wells have been found to offer the highest NPV, IRR with the shortest payback period hence making them the most attractive option financially for field development.
2. Vertical wells provide a cost-effective solution for simpler zones but also less efficient in thin or heterogeneous reservoirs
3. Directional wells represent a middle ground between horizontal wells and vertical wells; however, they are most suitable for complex structures.
4. The liquid lift optimization provides a moderate benefit, but it is less profitable compared to infill drilling due to its higher operating costs and produced water handling costs.

It is therefore seen in these analyses that that horizontal well drilling will provide the optimal strategy for maximizing recovery and profitability in Toma South Oilfield.

5: CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

Below are some key conclusions which have been summarized.

5.1.1 RESERVOIR BEHAVIOR AND INFILL POTENTIAL

- Toma south oilfield exhibits heterogeneity especially in Bentiu 2A and Aradeiba main sand layers which have thin and stratified zones that have by passed oil.
- Areas with high remaining oil saturation (ROS) were identified by reservoir simulations near structural heights, faults and undrained compartments which made them ideal target areas for placing infill wells.
- The base case scenario without adding more wells will limit the recovery factor to 50.2% by 2025 which leaves a significant volume of recoverable oil in the reservoir.

5.1.2 INFILL WELL OPTIMIZATION

- Horizontal wells have shown the highest incremental recovery with 4.8% improvement in recovery factor to about 54.9% and a cumulative oil production increase of 17.3% MMstb by 2028
- Vertical wells can provide a recovery improvement of 3.5% and are suitable for thicker reservoir intervals like Bentiu 1A and Bentiu 1D which have higher vertical permeability.
- Areas with faults are good for directional wells that offer a flexible alternative compared to vertical and horizontal wells

5.1.3 ECONOMIC PERFORMANCE

- Horizontal Wells are the best option financially with their highest net present value (NPV) of \$215.46 million, an internal rate of return of 28% with the shortest payback period of 2.5 years
- Although vertical and directional wells are less profitable than horizontal wells, they remain economically viable especially in areas where horizontal drilling may be possible.

- Artificial lift optimization gives a moderate economic benefit but is less competitive due to its high operational costs associated with it like increased water production

5.1.4 CHALLENGES AND RISKS

- Increasing water cut is a challenge for all development scenarios. Effective water management strategies like water shut off and reinjection need to be employed
- Drilling horizontal and directional wells in thin or fault dominated reservoirs needs advanced technology like geo-steering which increase operational complexity and risk

5.2 RECOMMENDATIONS

Based on the conclusion discussed above, the following recommendations are being proposed for the development of Toma South oilfield.

- It is recommended that six horizontal wells should be drilled to target bypassed oil in Bentiu 2A and Aradeiba main sand. Those horizontal wells should be designed with a lateral length of approximately 400 m to maximize reservoir contact while also minimizing operational costs.
- Drill four vertical wells in thicker reservoir intervals such as Bentiu 1A and Bentiu 1D so that vertical permeability will support efficient drainage.
- Five directional wells should be drilled to access compartments that are near faults and structural edges.
- The ESP setting in existing wells should be optimized to enhance liquid lifting capacity and maintain production rates with focus on wells with moderate water cut to delay water breakthrough
- It is recommended that water shut-off techniques should be done on wells that produce water at a high rate to reduce water production rate.
- Expansion of water handling facilities and considering re-injection of produced water into reservoir to help in maintaining pressure and minimizing surface handling and treatment costs.
- It is recommended that oil prices should be monitored closely and adjust development plans when necessary to ensure profitability under varying market conditions.
- It is recommended that a phased implementation plan for infill drilling is developed starting with high-priority wells in areas that have shown highest remaining oil saturation and recovery potential.

Final remarks

Toma South Oilfield has a significant opportunity for maximizing hydrocarbon recovery through this optimized infill well placement. This study has therefore

demonstrated that a combination of advanced reservoir simulation coupled with technical innovation and economic analysis can offer a better insight for field development. Therefore, implementing the recommendations made above can help the operating company to achieve good recovery and profitability while ensuring sustainable management of the field.

DECLARATION

I J. Junior Rier Mayek confirm that this work submitted for assessment is my own and is expressed in my own words. Any uses made within it of the works of other authors in any form (e.g. ideas, equations, figures, text, tables, programs) are properly acknowledged at the point of their use. A list of the references employed is included.

J. JUNIOR RIER MAYEK

August 21st, 2026

FUNDING DECLARATION,

I have no funding for my Manuscript. There was no funding.

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