Reservoir Simulation Framework to Support Marginal Field Development Planning

A thesis submitted to the faculty at African University of Science and Technology in partial fulfilment of the requirements for the degree of Master of Science in the Department of Petroleum Engineering

By

Oghenerobor AKPOBASAHA

Supervised by

Professor David Ogbe

African University of Science and Technology

www.aust.edu.ng

P.M.B 681, Garki, Abuja F.C.T, Nigeria

Abuja, Nigeria.

May, 2023

CERTIFICATION

This is to certify that the thesis titled “RESERVOIR SIMULATION FRAMEWORK TO SUPPORT MARGINAL FIELD DEVELOPMENT PLANNING” submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the Award of the Master’s degree is a record of original research carried out by OGHENEROBOR AKPOBASAHA in the Department of Petroleum Engineering.

Reservoir Simulation Framework to Support Marginal Field Development Planning

By

A THESIS APPROVED BY THE PETROLEUM ENGINEERING DEPARTMENT

RECOMMEND:

18 December 2023
....
Supervisor Prof. David Ogbe

....
Committee Member, Dr. Alpheus Igbokoyi

....
Head, Department of Petroleum Engineering

APPROVED:

....
Chief Academic Officer

....
Date

COPYRIGHT

ABSTRACT

Dynamic simulators are practical tools used in the oil and gas industry to help make informed decisions, optimize production, reduce risks, and maximize hydrocarbon recovery. They are fundamental for the success and profitability of oil and gas operations, playing a vital role in reservoir engineering and management practices.

The objective of this study is to propose an optimal development framework for a marginal field located offshore in the southeast Niger Delta, where only available data are from neighbouring fields. The process involves estimating volumes of hydrocarbon-bearing sands through reservoir characterization and static modeling, developing a simulation model, and using it, along with decline curve analysis, to estimate produced hydrocarbon volumes. Next, production constraints are formulated for infill wells using a well simulator to determine optimal flow rates and tubing sizes. An optimized production strategy is then developed by analyzing the sensitivity of the constraints and parameters to oil recovery. Sensitivity analyses were conducted on Tubing Head Pressure (THP) and injection rates to identify the most effective production strategy throughout the 15-year life of field Finally, an economic analysis is performed to assess the project profitability. The study also includes identifying and assessing the environmental, subsurface, and surface risks associated with the field development plan.

Based on these findings, it is recommended that the proposed reservoir simulation framework used in the Ratson Sand C project can be applied to similar fields to achieve maximum recovery.

Keywords: Field development planning (FDP), reservoir simulation, decline curve analysis (DCA), production optimization, economic analysis, risk mapping, sensitivity analyses

DEDICATION

I dedicate this work to the Almighty God for His strength in guiding me day by day. I also extend my gratitude to the community at African University of Science and Technology (AUST), as well as my family and friends, for their unwavering support and invaluable advice.

ACKNOWLEDGEMENTS

My deepest gratitude goes to God almighty for a supervisor and “reservoir daddy”, Prof. (Emeritus) David Ogbe, for his guidance and unwavering support in helping me understand the difference between “simulation” and “stimulation” and the intricacies of reservoir engineering, shaping me always to becoming better.

I would also like to express my heartfelt appreciation to my committee member and Head of Department, Dr. Alpheus Igbokoyi, for his fatherly presence and constant support whenever I needed guidance. My best regards also to Dr. Haruna Onuh for his support during my studies and special thanks and appreciation to my amazing course mates, Beatrice Ejeh, Nwankwo Ifeanyi, and Ngala Clinton. Their companionship and camaraderie throughout this journey are second to none.

I would also like to acknowledge the management of Oasis International College, Kado, particularly Mr. Temitope Ogundipe, for their valuable contributions and support.

Table of Contents

List of Figures

List of Tables

APPENDIX

Chapter 1: Introduction

1.1. General Overview

The Field Development Plan (FDP) provides the technical blueprint for optimizing field development in terms of cost and the production strategy for a field. More so, an FDP can be used to keep the production of a field competitive (Sorgard, et al., 2023). Having limited data for a Field Development Plan (FDP) can present several challenges such as uncertainties in reservoir management, cost overruns, infrastructure limitations, and regulatory compliance issues.

This research study centers on crafting an FDP customized for a case study of a green-marginal field. A marginal field presents distinct opportunities for smaller operators, new technologies, and innovative business models to maximize its energy production. The primary objective of this study is to develop a framework for marginal field development planning which includes reservoir characterization, reserves evaluation, proposing an optimal production strategy, conducting environmental and risk assessments, and performing an economic analysis.

The premise of this research is outlined in the following section as the research problem is identified, the research questions posed, and the objectives are clearly written. Furthermore, the significance of this study is discussed as well as the scope of the study. The utility of this work to not only the industry but the research community is clearly identified.

1.2. Field Location and History

The Ratson field is located offshore south-eastern Niger Delta at approximately 475 ft water depth. This field, located in the offshore depobelt of the Niger Delta Sedimentary Basin, was discovered through the drilling of Ratson-1 well as a vertical well with total depth of 8185.7ft. The well encountered four hydrocarbon-bearing sands namely: A, B, C and D. The Ratson-1 exploratory well was side-tracked (Ratson-1ST) and drilled to a total depth of 12,998ft MD, then plugged and abandoned. Sand C, which is the focus for this thesis, is an oil and gas-bearing reservoir penetrated by both Ratson-1 & Ratson-1ST wells. Four hydrocarbon-bearing sands namely Sand A (gas), Sand B (gas), Sand C (gas and oil) and Sand D (gas) were correlated and mapped. Structurally, the Sand C pool is trapped between two counter-regional faults.

1.3 Problem Statement

A Field Development Plan (FDP) serves as a strategic roadmap for developing a green field or optimizing production in a brown field. Brown field FDPs are typically evaluated to enhance production, while green field FDPs face the challenge of limited data due to the wells being primarily used for exploration purposes. Therefore, it is crucial to formulate a reservoir simulation framework to develop an accurate FDP to effectively maximize production potential in newly discovered fields.

1.4 Research Questions

The proposed research is designed to address the following questions:

1. What are the volumes of hydrocarbons in place in the Ratson field?
2. What possible strategy/strategies can be utilized for optimum hydrocarbon production and recovery?
3. What are the recovery factors for the hydrocarbons in place?
4. What possible uncertainty and risks are associated with the discovery, development, and abandonment phases?

This study aims to address the above research questions. The approach involves characterization of the reservoirs, building static model, and dynamic modeling and analyses, including decline curve analysis (DCA), reservoir simulation, economic analysis, environmental and risk assessments to address the project uncertainties. These uncertainties can potentially hinder the development of a comprehensive Field Development Plan (FDP).

1.5 Objectives

This project aims at achieving the following objectives:

1. To estimate the volume of hydrocarbon bearing sands using static modeling.
2. To build and initialize a simulation model of the Sand C that correlates with estimated static volumes
3. To estimate the volume of produced hydrocarbons using the simulation model and decline curve analysis.
4. To formulate a set of production constraints for infill wells by using a well simulator to determine the optimum flow rates and tubing sizes.
5. To develop an optimized production strategy by analyzing the sensitivity of production constraints and parameters to oil recovery.
6. To perform an economic analysis to determine the project's profitability.
7. To identify and assess the environmental, subsurface, and surface risks associated with the field development plan.

1.6. Significance of Study

The expected outcome of this research is the creation of a reservoir framework tool specifically tailored to maximize production in a green marginal field. This tool will have wide-ranging applications in reservoir management, well completion design, and the analysis of field development economics. Moreover, the research endeavors to deepen our knowledge of field development processes while highlighting the critical significance of precision, efficiency, and cost-effectiveness.

To accomplish these objectives, proactive and cost-efficient solutions in the form of field and well simulators are proposed. These simulators or models will provide valuable insights and assist in overcoming the challenges associated with optimizing production in a green marginal field. Reservoir simulation can be traced back to the early 1950s when computer technology was starting to prove its usefulness as major commitments to fundamental research on the numerical solution of flow equations were explored (Breitenbach, 1991). It can be applied to any stage of the reservoir life cycle for optimization purposes. Utilizing the benefits of reservoir simulation tools, the research aims to contribute to the advancement of field development practices, ensuring that they are characterized by accuracy, effectiveness, and economic feasibility.

This work is presented in five chapters. Chapter 1 provides the introduction to the study, while Chapter 2 offers a theoretical background to enhance our understanding of field development plans, including their application to various fields within and outside the Niger Delta region. In Chapter 3, the methodology used in developing a base simulation model, along with well models incorporating THP and gas injection rate sensitivity analysis, is described. The fourth chapter analyzes the results and discusses the comparative performance of the models. Lastly, Chapter 5 presents the major observations and the conclusions derived from the study before describing a set of recommendations to improve the results of the work.

Chapter 2: Theoretical Background of Niger Delta Fields

To understand the Niger Delta Fields and their reservoirs, it is important to review some of the work done by past researchers on this topic. There exists an extensive literature that provides valuable insights into the history of the Niger Delta field, regional and geological setting of the Ratson field, field development planning usually associated with the Niger Delta Fields including the production and exploration practices commonly used in the Basin.

2.1 History and Geology of the Niger Delta Fields

2.1.1 History of the Niger Delta Fields

The Niger Delta is known to be one of the largest petroleum prolific producing deltas. It is a large delta formed by the Niger River in West Africa, covering parts of Nigeria and surrounding countries. It is argued that the sedimentary volume to surface area of the Niger Delta is very high and encompasses other deltas such as the Cross River Delta, extending into the continental margins of neighboring Cameroon and Equatorial Guinea (Reijers T. P., 1996) The Niger Delta is known for its extensive sedimentary deposits, including sands, clays, and organic-rich layers, which have been laid down over millions of years. The catchment area is said to extend over savannah-covered lowlands stretching about 300 km from apex to mouth and covering an area of at least 75000km^2 (Doust, 1989). Figure 2.1 show the major deltas in the world and Figure 2.2 illustrates the geological extent of the Niger Delta basin.

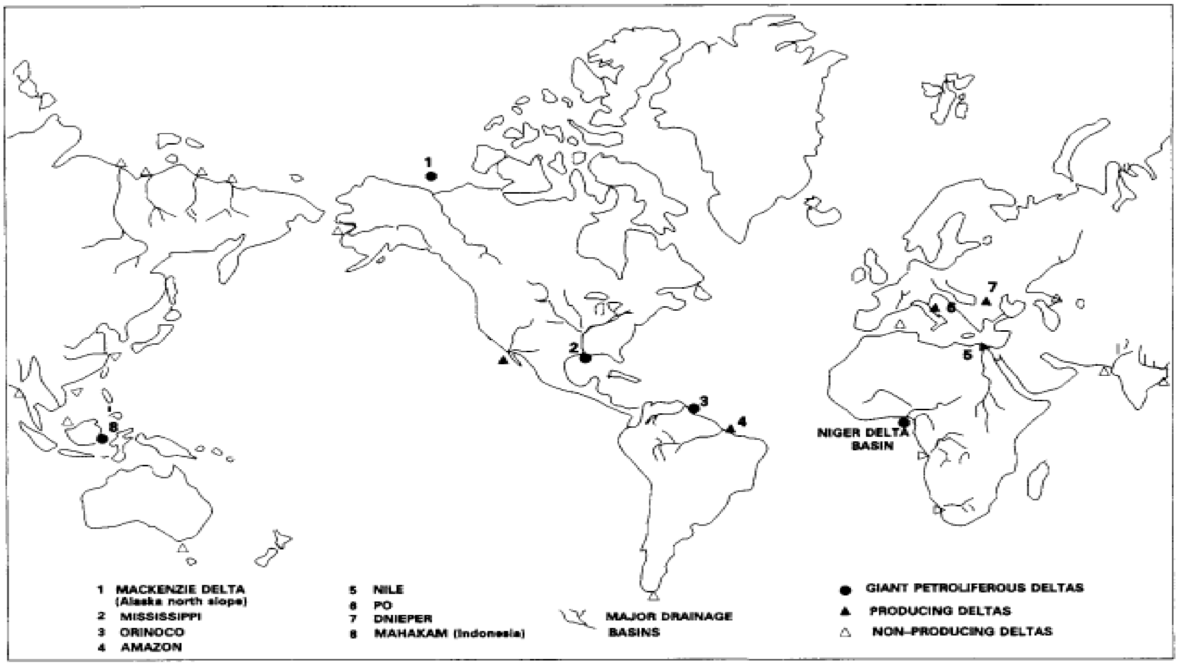

Figure 2.1: World's major petroleum-producing deltas (Reijers T. P., 1996)

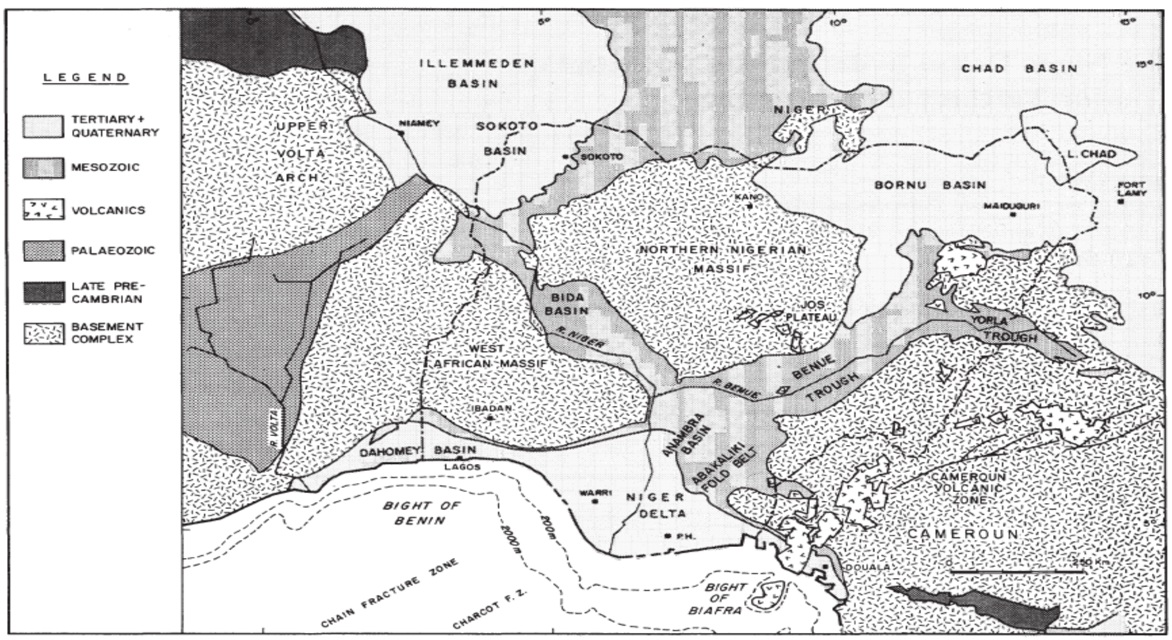

Figure 2.2: Nigeria and the geological extent of the Niger Delta (Doust, 1989, p 204)

After fifty years period of exploration, oil was first discovered in Nigeria in 1956 at Oloibiri in the Niger Delta by the exploration company Shell D'Arcy. In April 1956, the company was renamed Shell-BP Petroleum Development Company of Nigeria Limited, which held the exclusive license for oil exploration and production (Shell PLC, n.d.). Shell-BP reported a production rate of 5,100 barrels per day (BBL/D) which made Nigeria to be one of the major oil producers (Azeezat, 2020). Since then, exploration and field development activities have continued into the deeper frontiers of the delta.

2.1.2 Geology of the Niger Delta Fields

Geologically, the Niger Delta is said to have formed during the tertiary period. However, this time scale is currently divided into two epochs: Paleogene and Neogene. The International Commission on Stratigraphy (ICS) is empowered to revise the geologic time scale and rename periods when as needed as geological time scales and classification systems are subject to revisions as new scientific discoveries and research emerge (Wikipedia, 2023).

The Niger Delta Petroleum system follows the petroleum system naming convention of Magoon and Dow (Magoon & Dow, 1994), where the source rock is mentioned first, followed by the reservoir rock containing the largest volume of hydrocarbons (Tuttle, Charpentier, & Brownfield, 1999). Several studies have been conducted to examine the various timelines and developments of the Niger Delta. The Niger Delta is stratigraphically classified into three formations, namely, the Benin, Agbada, and Akata Formations, due to its lithofacies; the continental to marginal-marine sands of the Benin Formation, the paralic Agbada Formation and the marine shales of the Akata Formation (Short & Stauble, 1967). Within these designated stratigraphic units, there are smaller, distinct subdivisions that can be represented on a map. These subdivisions are differentiated from one another based on the differences in their lithology, emphasizing that the composition and other physical characteristics of the rocks in each subdivision vary. Figure 2.3 illustrates that the Agbada and Benin Formations are mainly found in the northern region (Tuttle, Charpentier, & Brownfield, 1999, p. 22). As we move towards the deeper parts of the basin, a change occurs, and the Akata Formation becomes more prevalent. In this transition zone, the Agbada and Benin Formations become thinner and eventually disappear as we move towards the sea. Figure 2.4 obtained from Tuttle et al (1999) exemplifies more the development of these stratigraphic units and attaches a geological timeframe to them.

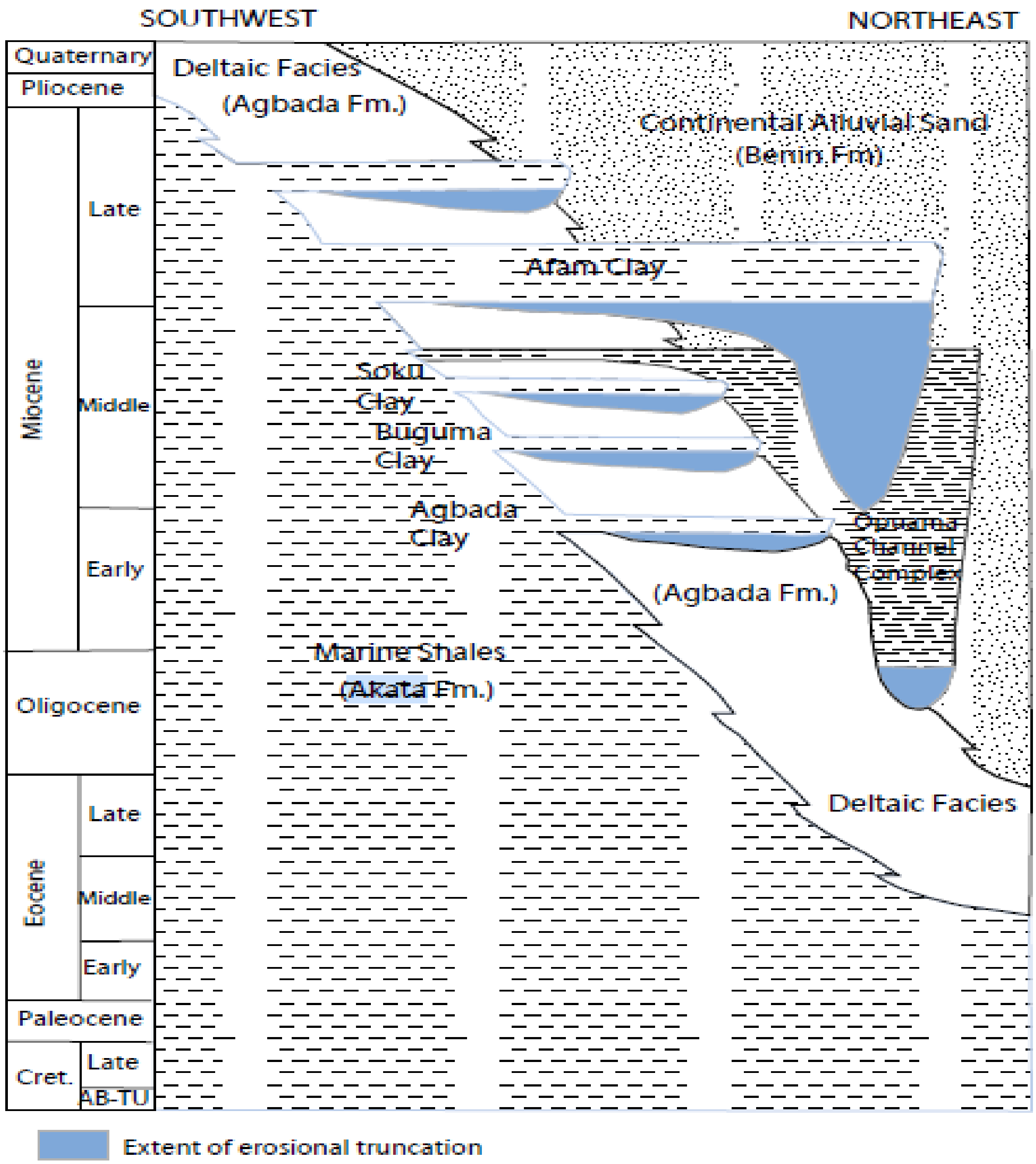

Figure 2.3: Stratigraphy units of the Niger Delta (Tuttle, Brownfield & Charpentier, 1999)

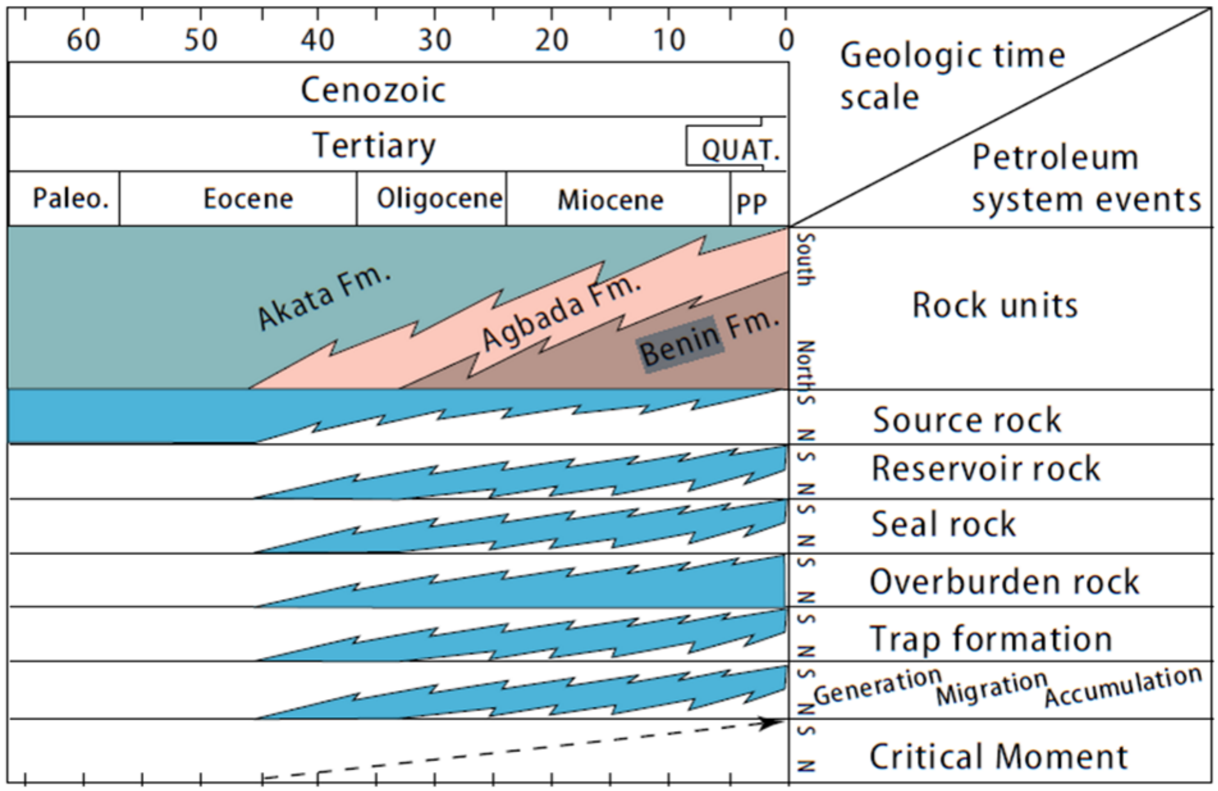

Figure 2.4: Events chart for the Niger Delta Petroleum System (Tuttle, Brownfield & Charpentier, 1999)

Nevertheless, more recent studies provide useful insights into the geology of the delta. In 2012 Obiadi, Ozumba, and Osterloff (2012) defined seven regional depobelts in the Niger Delta, namely, the Northern Delta, Greater Ughelli, Central Swamp I, Central Swamp II, Coastal Swamp I, Coastal Swamp II, and Offshore. However, some studies, e.g., Oluwajana, Ehinola, Okeugo & Adegoke (2017), categorize the Niger Delta Basin into five depobelts, i.e., the Northern Delta, Greater Ughelli, Central Swamp, Coastal Swamp, and Offshore depobelts. Nonetheless, these depobelts are argued to have been developed from the Eocene era to the present (Tuttle, Charpentier, & Brownfield, 1999, p. 5). Furthermore, these depobelts are acclaimed to be independent units with respect to sedimentation, structural deformation and hydrocarbon generation, migration, and accumulation (Evamy, Haremboure, & Kamer, 1978).

Additionally, Reijers (2011) argued that the traditional stratigraphic classification system of the Niger Delta can be further analyzed, considering plate tectonics and eustatic sea-level rises. Using this approach, one can more precisely determine the ages and relationships of rock layers based on the fossils they contain and the associated radiometric dates. Figure 2.5 from Reijers (2011) shows key lithological elements of the Niger Delta and the starting point for a new delta-wide lithostratigraphy.

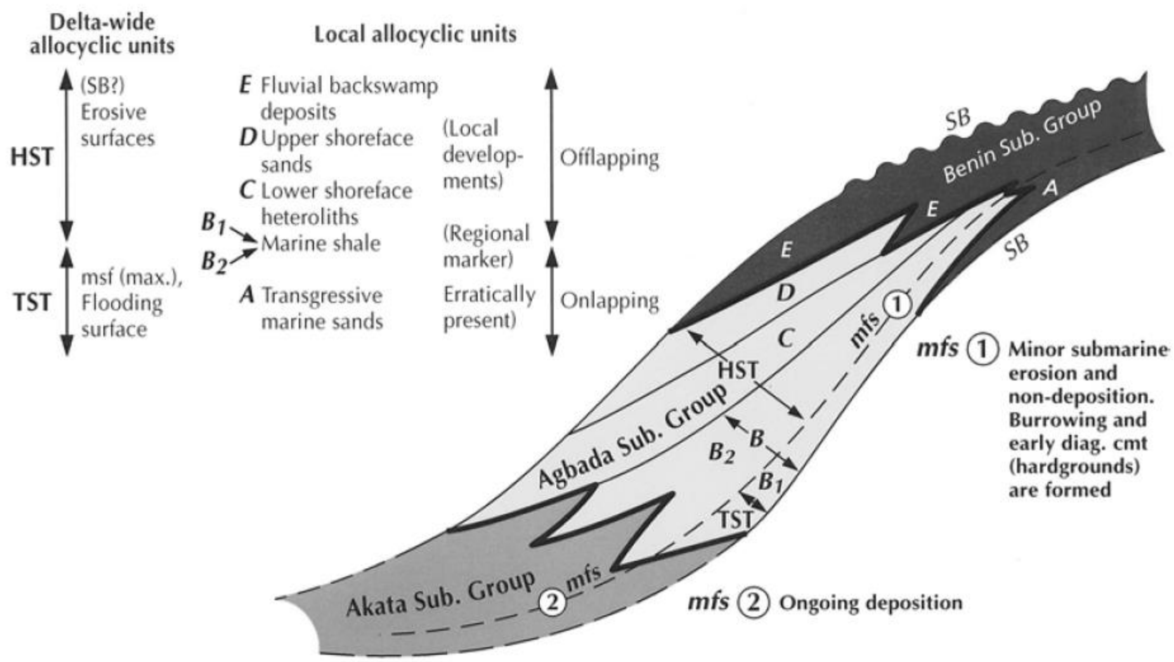

Figure 2.5: Standard Vail (1987) sequence with internal allocyclic units in the Niger Delta (Reijers 2011, p. 141)

Depositionally, the sand layers in the reservoirs were likely formed in different places (Olayiwola & Bamford, 2019). These places include areas like river deltas with channels and distributaries, inner parts of fan systems with slopes, underwater flows that carry sediments, and areas where the sea level rises and covers the land. Figure 2.6 shows the deformation system obtained from the work of Hooper et al (Hooper, Fitsimmons, & Vendeville, 2002). They considered the development of a fold system that lies buried under the upper slope, just seaward of the modern shelf-slope break in the southern part of the delta.

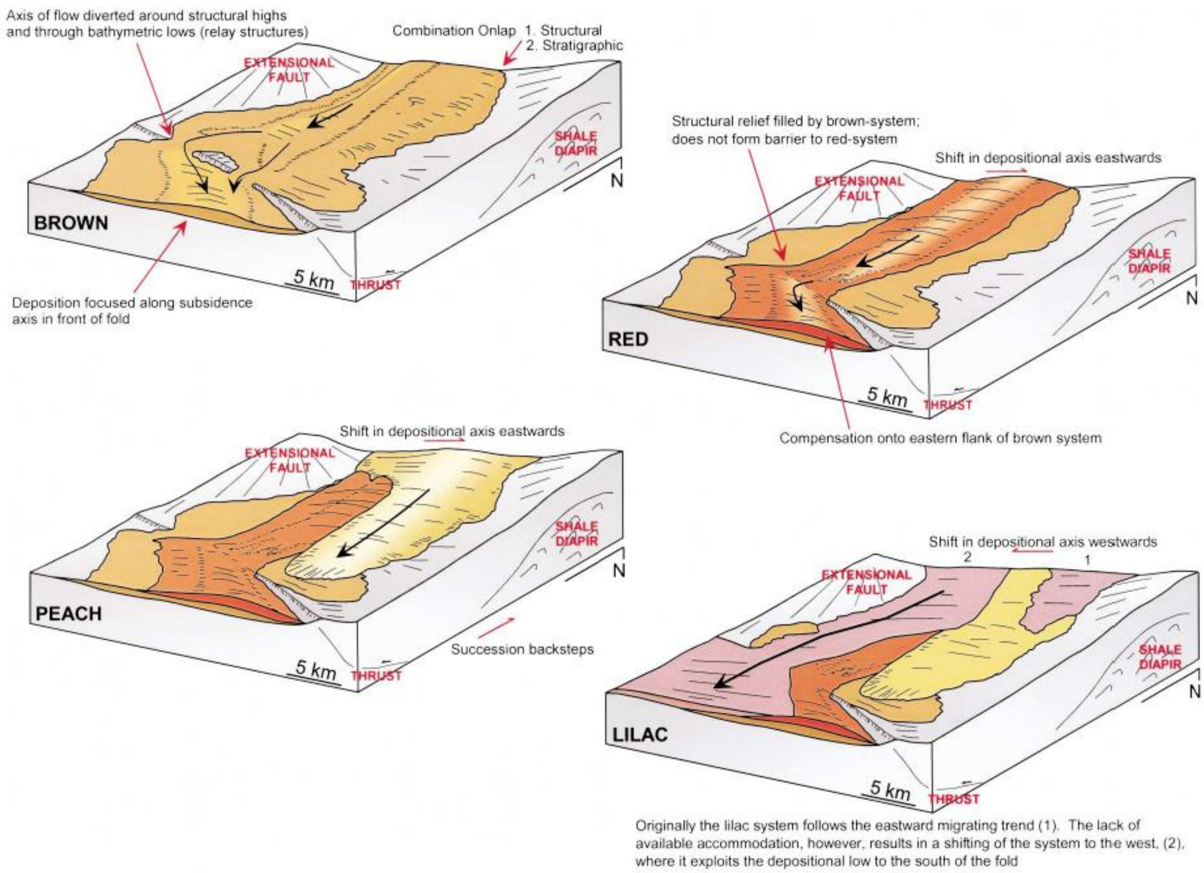

Figure 2.6: Stacking of depositional belts (Hooper, Fitsimmons & Vendeville, 2002)

2.2 Regional Geology of Ratson Field

The Ratson field is located offshore in the south-eastern Niger Delta at approximately 475 ft water depth within the offshore depobelt of the basin. It is important to note that the properties of individual fields within the Niger Delta have been the focus of studies overtime. These properties can be summarized as predominantly sandstone reservoirs with high porosity and permeability, and abundant hydrocarbon resources. In addition, it is well known for its structural complexity and the presence of both deep water and shallow water fields.

Most of the petroleum accumulations trapped in the Niger Delta are predominantly structural, found in the sands and sandstones of the Agbada Formation. They are trapped by rollover anticlines related to growth fault development (Eke & Okeke, 2016, p. 96). As defined by Emujakporue (2016, p. 337), the structural complexity increases from the North (earlier formed depobelts) to the South in response to increasing instability of the under-compacted, over-pressured shale. Furthermore, in the work by Dim (2016), hydrocarbons are said to occur at various shallow and intermediate zones; with a concentration of gas at the proximal end which is the northern section, oil and gas at the central, and oil at the distal end which is the southern part. This trend, attributed to source rock maturation from vitrinite reflection studies, is reflected in the data recovered from spudding the Ratson field. Out of the four hydrocarbon-bearing sands encountered, three were purely gas in small volumes, and the fourth sand which is focus of this research work is predominantly oil-bearing.

Adepoju, Adekola, Omotoye & Akinlua (2018) reported that the oils from the delta can be classified into two groups for a study. Upon degeneration, the south-eastern oils, which constituted one group, and the north-western and central oils, which constituted another group, indicated that the reservoir conditions differ. This is attributed to migration effects.

In the extensive study by Osinowo, Ayorinde, Nwankwo, Ekeng and Taiwo (2018), which entailed structural and horizon mapping of a 3D seismic volume, petrophysical studies of over sixty (60) wireline logs, stratigraphic analyses, reservoir property modeling, and production information, were adopted to study a southern Niger Delta field (Eni field) that has been experiencing production decline with an increase in water output. The result indicated an average porosity value between 0.238 and 0.241, while water saturations' ranges between 0.127 and 0.13. The reservoir pressure ranges from 2328 to 2553 psia, and the average reservoir temperature ranges from 170 to 180°F. The average American Petroleum Institute (API) gravity for the encountered formation fluids ranges from 20.5 to 34.2°API, while the initial solution gas-oil ratio (GOR) ranges from 350 to 396 scf/stb. Oil viscosities and gas gravity (air=1) were determined to vary from 0.57 cp to 2.57 cp and 0.65 to 0.67, respectively. The formation volume factor (Boi), ranges in value from 1.209 RB/STB to 1.33 RB/STB across the delineated reservoirs. The generated information from the core, PVT, and production information served as a guideline for the analogue data used in this study.

2.3 Production Mechanisms in Niger Delta

The recovery of hydrocarbons from reservoirs in the Niger Delta is significantly influenced by the expulsion of pore fluids resulting from gravitational deformations and shale tectonics (Mourgues, Lecomte, Vendeville, & Raillard, 2009). Hospers (1965) specifically argued that the geophysical features observed strongly support the concept of subsidence under load as the prevailing production mechanism in the Niger Delta. The argument of overburden pressure on seals and the confinement of fluids leading to rapid expulsion whenever a fracture is induced is well conceived. However, other authors, such as Oseh and Omotara (2014), have argued that the Niger Delta reservoirs are predominantly influenced by water drive mechanisms. It is believed that a combination of drive mechanisms including water, gravity, overburden, and gas-in-solution are more predominant in the recovery of fluids in the Niger Delta. The relative contribution of each mechanism depends on the specific reservoir characteristics and fluid properties.

2.4 Field Development Plans in Niger Delta

Several papers on FDPs (Field Development Plans) describe how to produce a field or address challenges during production in the Niger Delta. Most of these developmental plans incorporate production simulations, as they play a central role by providing critical information for field development, reservoir management, and production optimization. Some of this published works on Niger-delta fields includes that of, Ezebialu, Ubituogwale, Odegua, and Idehen, (2020), Carpenter (2022) and Ashiedu & Olarewaju (1998) to mention a few.

Also, in the work by Amihere-Ackah (2020), it highlights a field development plan for Trinidad was considered which utilizes waterflooding. Likewise, Behrenbruch (1993) conducted an assessment of an offshore; predicted the reservoir's performance under anticipated production conditions, and devised optimal facilities to align with the projected production forecasts.

These FDPs highlighted and more offer a comprehensive understanding of the reservoir's behavior and aid in making informed decisions to maximize hydrocarbon recovery and field performance. However, for these benefits to occur, relevant input data and realistic assumptions are needed to aid field development, reservoir management, and production optimization. Thus, the essence of this research work is showcased, as it aims to answer a question on how best to develop a marginal field in the southeastern Niger Delta with no production data. The methodology of this study is presented in the next chapter.

Chapter 3: Methodology

3.1 Overview

In this study, simulations and analyses are conducted to develop a reservoir framework for the development of a marginal field. The objective is to evaluate the effectiveness of reservoir tools in creating an efficient field development plan for fields where production data is either unavailable or limited. The following methodology is adopted to develop the framework and evaluate its performance. The study was carried out in two phases. In Phase I, a static model of the Ratson field was developed by Ejeke (2022). A summary of the static model development is given in this Chapter. The dynamic modeling and analysis which formed the second phase of the FDP is also presented in this Chapter.

3.2 Static Model of the Ratson Field

The use of static models is crucial in the reservoir characterization process which provides the initial framework for understanding the reservoir's properties and behavior. This characterization typically involves the collection and integration of various data sources, including well logs, core samples, seismic data, and geological information. Also, a static model can be used to define optimal well placement, risk assessment, and to perform a dynamic simulation and economic analysis. The available static data for this green-marginal field are obtained from seismic report and well logs which includes gamma ray, resistivity, density, porosity, and saturation logs from the Ratson-1 well. Additionally, the Ratson-1ST well provides information on gamma ray, resistivity, and facies. A well-to-seismic tie interpretation was performed to establish the depths of the various sands (Sand A, Sand B, Sand C and Sand C) and depth control in the Ratson field. Well-to-seismic tie, also known as well-to-seismic calibration, is a process in geophysics and exploration geology where well data and seismic data are aligned and correlated (Ezebialu, Ubituogwale, Odegua, & Idehen, 2020). Figure 3.1 shows the well log data of Sands C and D in the Ratson field. These seismic and well log data are well documented in the internal report presented by Ejeke (2022).

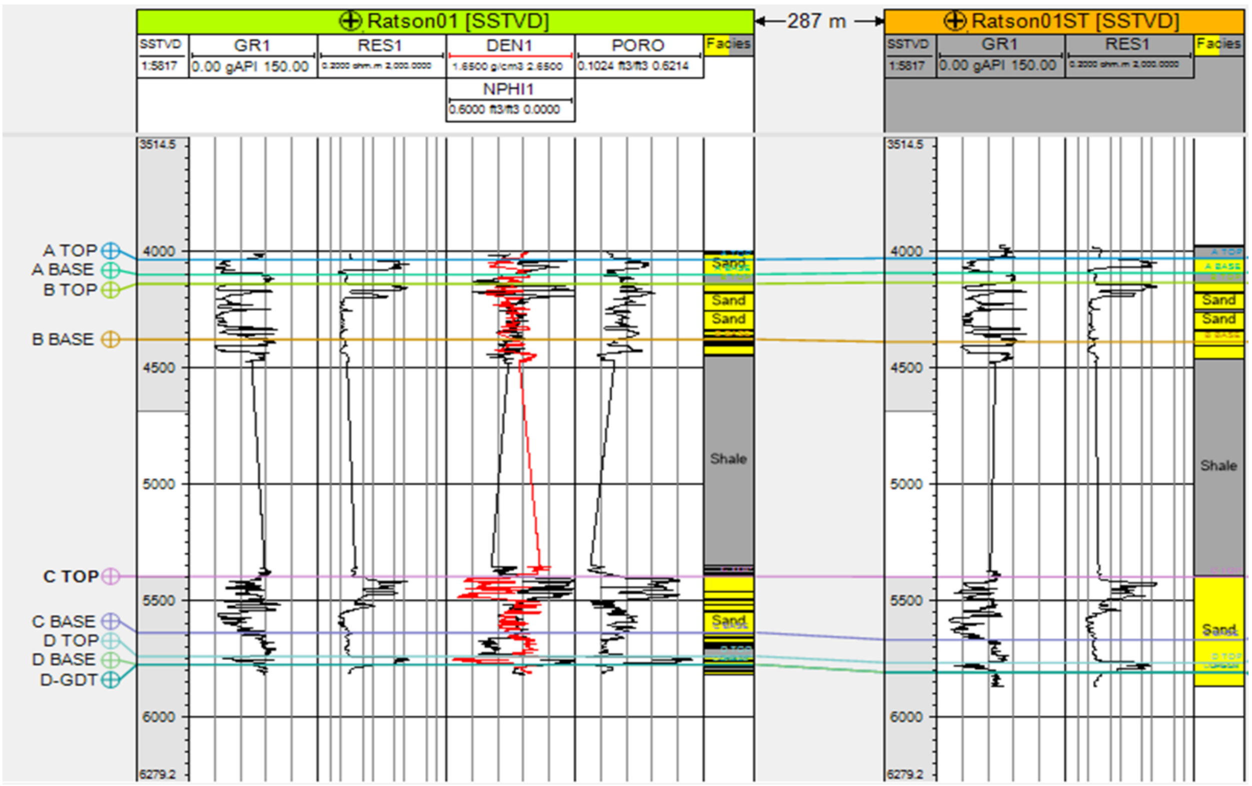

Figure 3.1: Sand C and D Well Log Correlation

3.2.1 Ratson Static Modelling of Geophysical and Petrophysical Properties

The static reservoir characterization of the Ratson field is divided into two categories: geophysical and petrophysical modeling. The geophysical modeling includes facies and structural modeling of the stratigraphy and fault lines. The petrophysical modeling include upscaling of logs, hydrocarbon distribution, permeability, and saturation modeling of reservoir sands. Facies, porosity, and NTG logs are upscaled using averaging methods to produce petrophysical property values for the individual cells within the model. Figures 3.2- 3.4 were obtained from Ejeke's report (Ejeke, 2022). Figure 3.2 shows the three faults identified in the geological report. Two of these faults, labeled as

2 and 3, bound the reservoir of interest. Figure 3.3 displays the facies model of all sands derived from the Sequential Indicator Simulation (SIS) algorithm. Facies models are employed to understand and represent the spatial and temporal distribution of different sedimentary rock types. A simple two-facies model (Sand and Shale) was distributed among the majority of sands of the Ratson field.

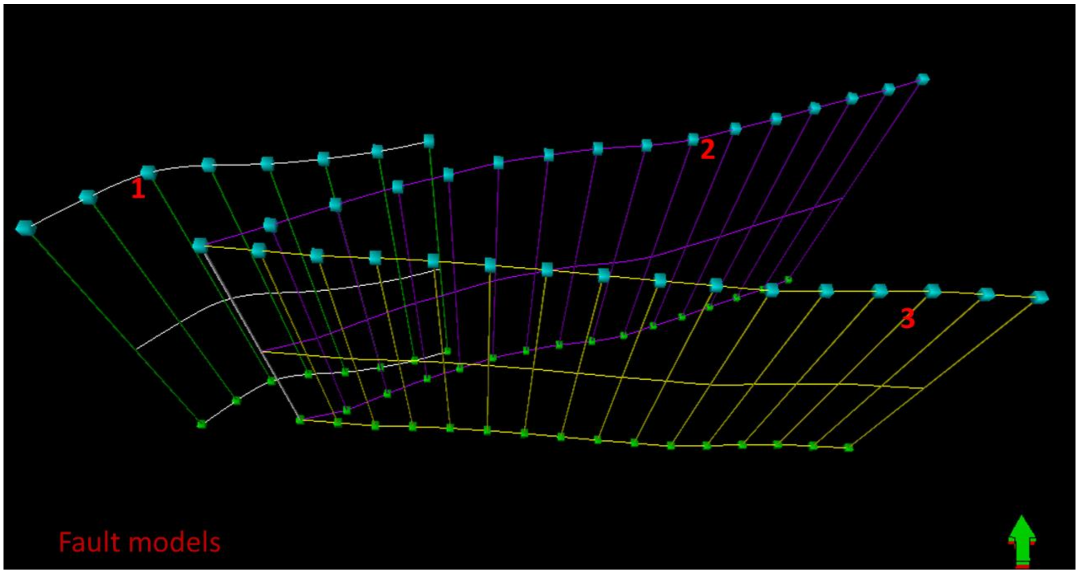

Figure 3.2: Structural Modelling showing faults

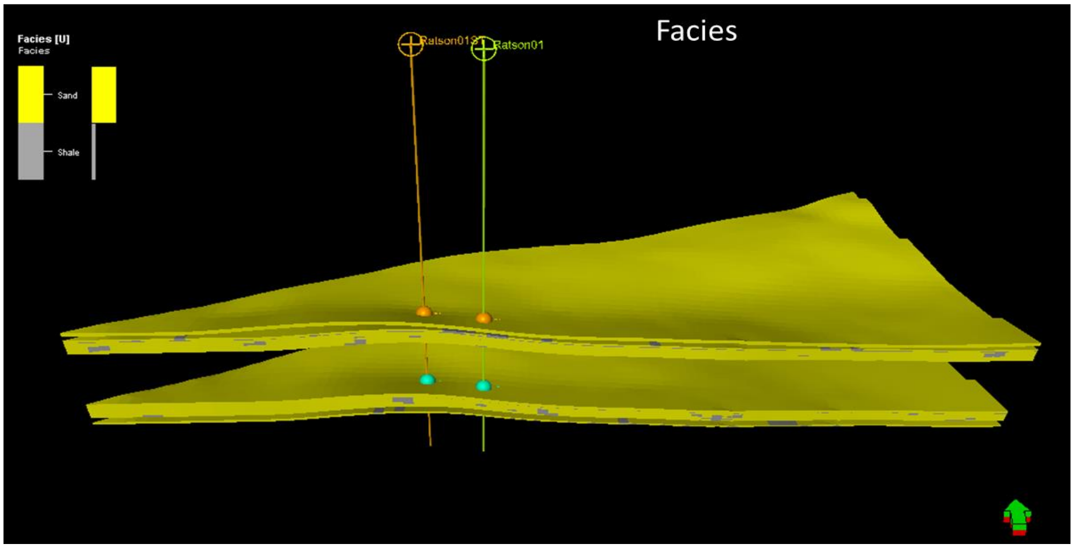

Figure 3.3: Reservoir A, B, C and D facies model

Figures 3.4 and 3.5 show the structural modelling of the horizons. The horizons are the building blocks for the structural models and grided 50mx50m to optimize the model resolution. Aside from accounting for their spatial variability and intersections, it ensures that the grid accurately represents the structural complexity of the Ratson field.

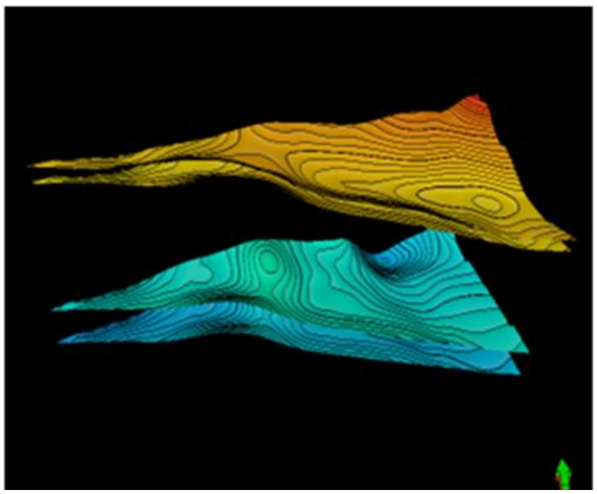

Figure 3.4: Horizon surface model

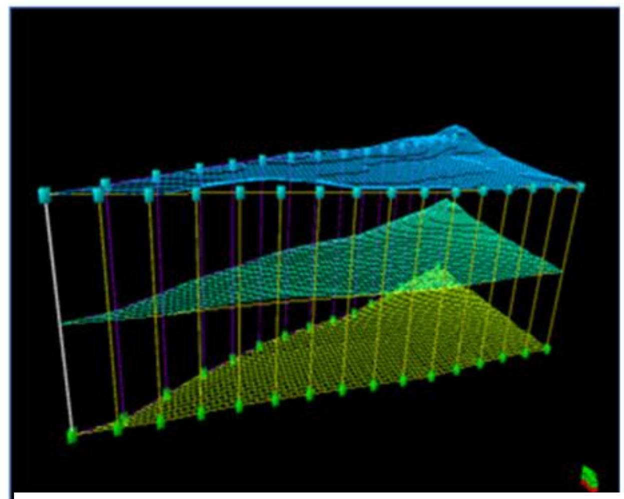

Figure 3.5: Reservoir grid model

Petrophysical models showing upscaling of logs, hydrocarbon distribution, permeability, and saturation modeling of data are shown in Figure 3.6 – 3.8. Figure 3.5 shows well logs upscaled for Sands C and D. This process aids in integrating and representing the well log data more effectively in reservoir characterization, modeling, and simulation. The good match indicates that heterogeneities within the reservoir are adequately captured in the model.

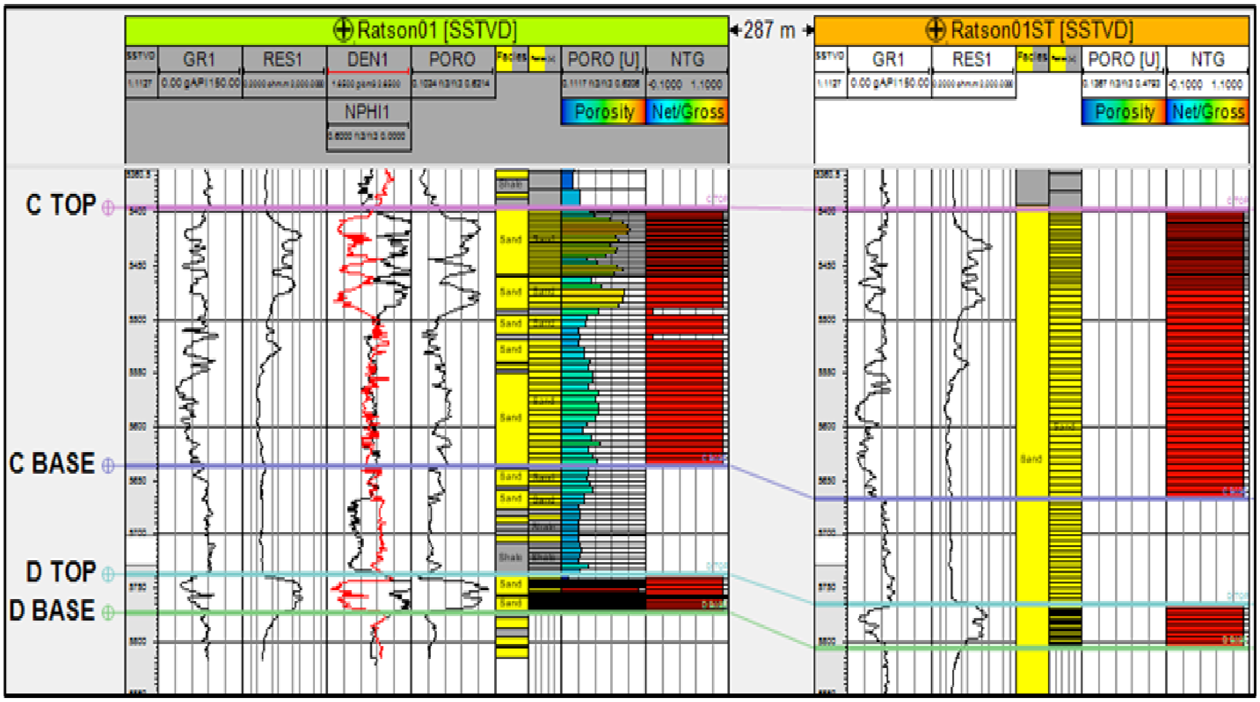

Figure 3.6: Sands C and D sands upscaled logs

The hydrocarbon distribution is shown in Figure 3.7. Note the figure also shows the fault assisted closures of the structural model for all sands. These faults play a significant role in the trapping and containment of hydrocarbons in subsurface reservoirs.

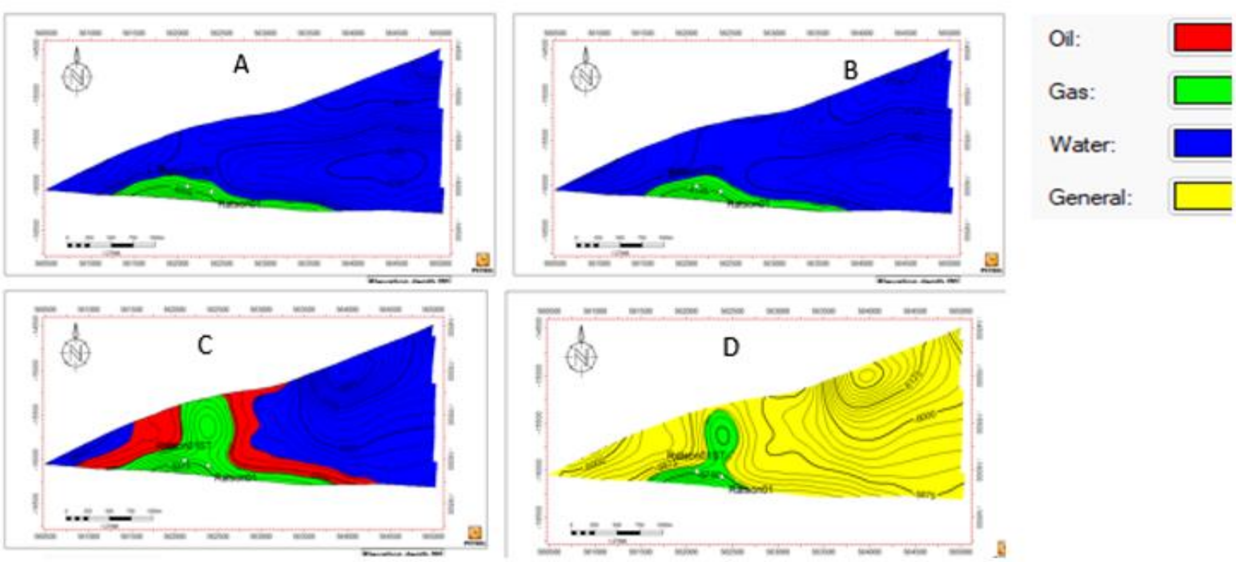

Figure 3.7: Ratson Maps and hydrocarbon distribution.

Ratson properties displayed in Figure 4.8 show the distribution of the petrophysical properties from the property models of this research work. Porosity models are used to understand and quantify the distribution of porosity within subsurface rock formations. NTG models show the reservoir quality and estimating the volume of hydrocarbons that can be potentially extracted from a reservoir; and the permeability models characterize the ability of rocks or geological formations to transmit fluids. Water saturation model is used in optimizing the movement and distribution of water subsurface to support primary recovery.

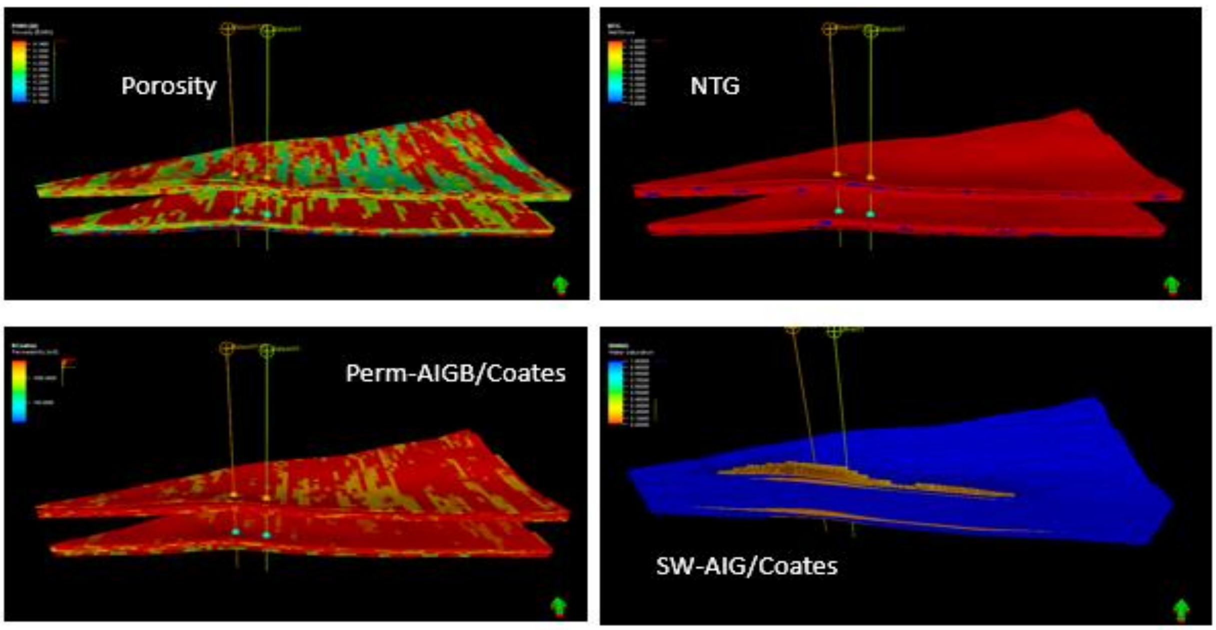

Figure 3.8: Ratson petrophysical properties

Figure 3.9 displays the output of the PVT Solver used in defining the fluid properties and the pressure regime of Sand C. It's worth noting that, for this study, values obtained from Standing's correlations are preferred. Standing's correlations are preferred because of their empirical accuracy, simplicity, and broad applicability

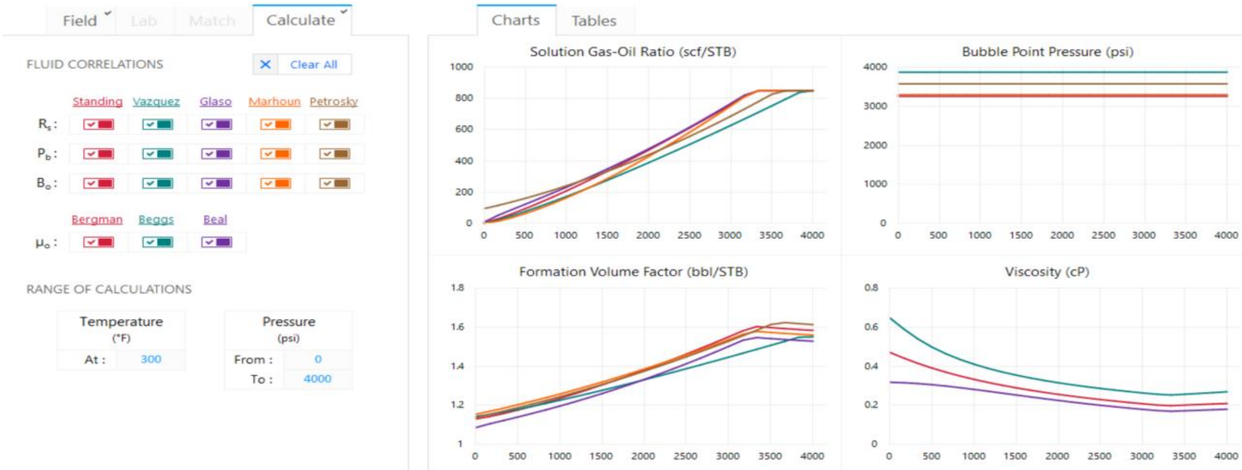

Figure 3.9: PVT fluid properties

Table 3.1 displays the output of the pressure regime from the Excel template developed in the work. The pressure gradients correspond to those recorded in neighboring fields within the Niger Delta.

Table 3.1:Pressure regime from Excel Template

SAND C		**Depth(ft)**	**TYPE FLUID**	**Pressure(psia)**
	Top of Sand	5395		2718
	Mid Sand (Gas Cap)	5445	GAS	2718
	GOC	5495	OIL	2718
	Mid Sand (oil Leg)	5528	<== Datum (OIL)	2730
	WOC	5560	OIL/WATER	2742

Additionally, tools like PVT Solver and a custom Excel spreadsheet were used for modeling fluid properties required in the dynamic models of the Ratson field. PVT (Pressure-Volume-Temperature) calculators are tools or software applications used in the oil and gas industry to perform calculations related to the behavior of hydrocarbon fluids in reservoirs, wells, and surface facilities, with PVT Solver serving as an example. Correlations, such as those by Standing (Standing, 1957), Vazquez and Beggs (Vasquez & Beggs, 1980), Glaso (Glaso, 1980), Marhoun

(Al-Marhoun, 1992), and Petrosky and Farshad (Petrosky & Farshad, 1998), informed the calculations within PVT Solver, which were used to define bubble-point pressures, oil viscosity, solution gas-oil ratio, and formation volume factors. Beggs and Robinson correlation (Beggs & Robinson, 1975) was used to define the oil viscosity. Figure 3.10 shows the input parameters into PVT solver.

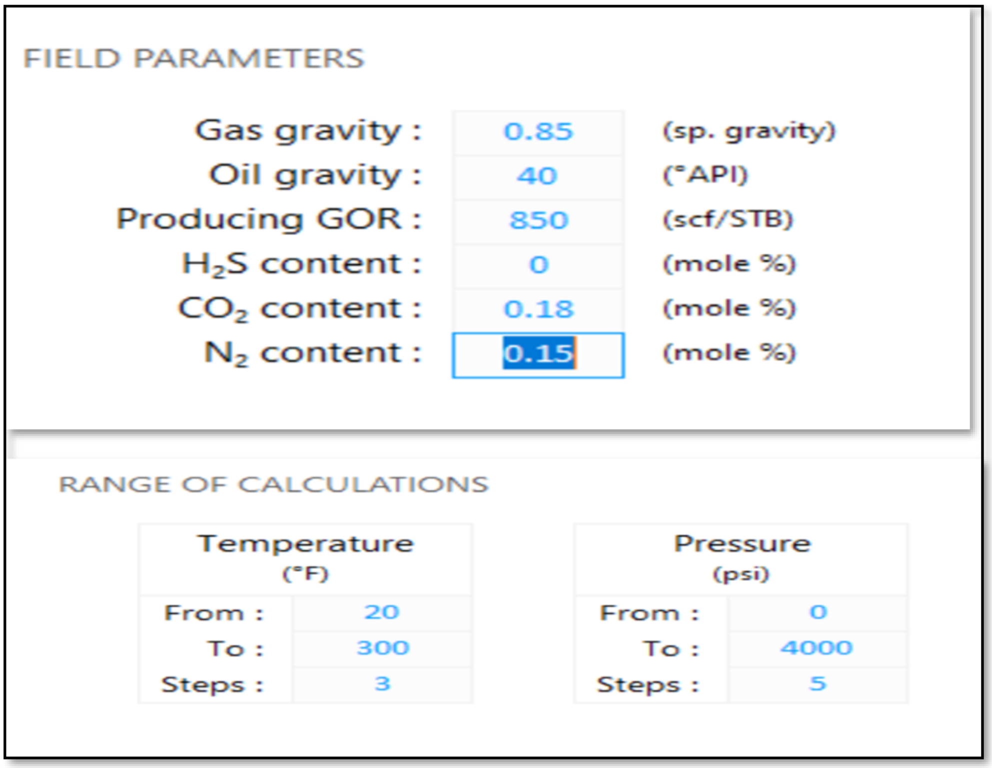

Figure 3.10: Input parameters for PVT Solver

An Excel spreadsheet was used to define the initial pressure and pressure regime of the different sands in the Ratson field. Ratson properties such as porosity, net-to-gross and permeability models are built by Sequential Gaussian Simulation and the permeability derived from correlations such as Coates and Aigbedion correlations. It is important to note that the Coates equation was developed for determining saturation and permeability at irreducible water saturation (Coates & Dumanoir, 1973) and Aigbedion's correlation was modeled for reservoirs without core data in the

Niger-delta (Aigbedion, 2007). Thus, water saturation for this research is modelled using the J-function since Sw height functions are well generated from Coates and Aigbedion.

A foundational understanding of these geological features and petrophysical properties allows for static and dynamic modeling to aid the planning of production strategies, well placement, and other aspects of reservoir development.

3.2.2 Volumes of Fluids in Place from Static Model

The reservoir properties, fluid contact, and gross rock volumes derived from the static model were used to calculate the volumes of fluids in place in the Ratson field. The static volumetric equations were used to calculate the volumes of Gas Initially in Place (GIIP) and Stock Tank Oil Initially in Place (STOIIP) are shown below.

The Volumetric formula employed to calculate the gas initially in place, GIIP, in standard cubic feet is given as;

$$GIIP = \frac{43{,}560 Ah\varphi(1 - Sw)}{Bg} \quad \text{(3.1)}$$

Where;

A = area, acres, h = net pay, ft, φ = porosity, Sw = water saturation, Bg = gas formation volume factor

The volumetric formula to calculate the oil initially in place, OIIP, in MMSTB is:

$$OOIP = \frac{7{,}758 Ah(NTG)\phi So}{Bo} \quad \text{(3.2)}$$

Where A = area, acres, h = net pay, ft, φ = porosity, Sw = water saturation, So (oil saturation) = 1 - Sw, and Bo = oil formation volume factor.

The formation volume factors were obtained from the PVT data described in the following section.

3.2.3 Reservoir Data and Constraints for Modeling Sand C of the Ratson Field

An Excel spreadsheet and a PVT calculator guided by assumptions and constraints derived from neighboring Niger-Delta fields were incorporated to assist in this analysis. Several of these data and assumptions are summarized in Table 3.2.

Table 3.2: Static Reservoir Data and Constraints for Ratson Sand C Modelling

ITEM	VALUE	UNITS	REMARKS
Solution gas-oil ratio	850	SCF/STB	Obtained from analog fluids
Reservoir temperature	160	^oF	Geothermal gradient
Oil gravity	40	^oAPI	Fluid sampling
Density of air at atmospheric pressure	0.076	lb/ft^3	S.T.P
Natural gas gravity	0.85	Air=1	Obtained from analog fluids
Water density	62.352	lb/ft^3	Obtained from analog fluids
Oil density	51.4	lb/ft^3	Obtained from analog fluids
Gas density	0.06462362	lb/ft^3	Obtained from analog fluids

3.3 Dynamic Modelling for Reserve Estimation of Sand C

Dynamic models, often referred to as reservoir simulation models, account for the changes in pressure, temperature, and fluid flow over time, helping engineers make more accurate predictions about reservoir behavior and optimal production strategies. The methodology of Phase II (dynamic modeling and analysis) of the FDP consists of six major steps, namely, model initialization, well design, production sensitivity analysis, decline-curve analysis (DCA), environmental and risk assessment, and economic analysis. Figure 3.11 shows a schematic of Phase II of the research methodology.

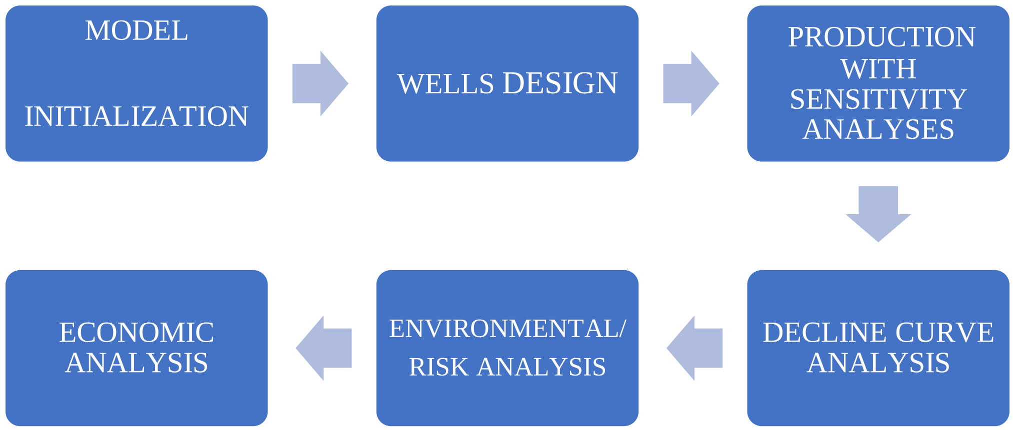

Figure 3.11: Schematic of Research Methodology for Developing an FDP

3.3.1 Model Initialization

A black oil simulator was used to initialize a comprehensive model of the Ratson Field. A black oil simulator is specifically designed for simulating reservoirs that contain a mixture of oil, gas, and water, with the term "black" referring to the oil's relatively high viscosity and presence of heavy components. The ECLIPSE industry-reference simulator offers the oil and gas industry a complete and robust set of numerical solutions for fast and accurate prediction of dynamic behavior in black oil, compositional, thermal, and streamline reservoir simulations and development schemes (SLB, 2023).

Model initialization is the process of establishing the initial conditions and input parameters for a simulation model. For dynamic reservoir simulation, the required input data includes values for initial pressure, temperature, and fluid saturations, as well as information on fluid composition, critical properties, viscosity correlations, and formation volume factors from the PVT data analysis.

Input data for model initialization are summarized in Figure 3.12 – 3.15 below, which highlights the different categories: case definition, PVT data, SCAL, and equilibrium data. Case definition involves the numerical settings of the model, including the reservoir type, simulation start date, model dimensions, and simulation units. PVT data is further divided into water PVT properties (PVTW), live oil PVT properties (PVTO), dry gas PVT properties (PVDG), and fluid density at surface conditions. Saturations were defined from Corey correlations, which were used to determine the Special Core Analysis (SCAL) parameters. Furthermore, the fluid contacts (Equilibrium data) used as inputs for model initialization were obtained from Ejeke's report (Ejeke, 2022). Figure 3.12 displays all entries used in the model initialization.

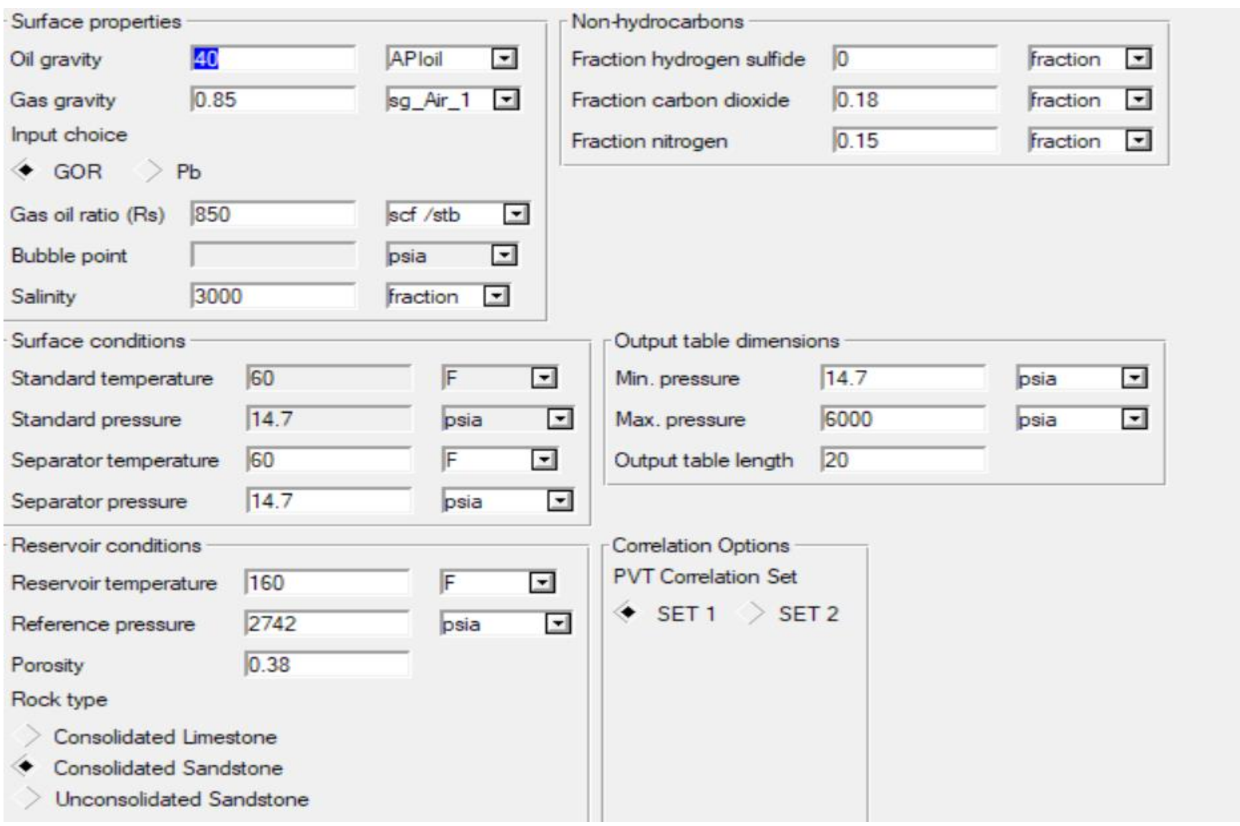

Figure 3.12: Case definition input data

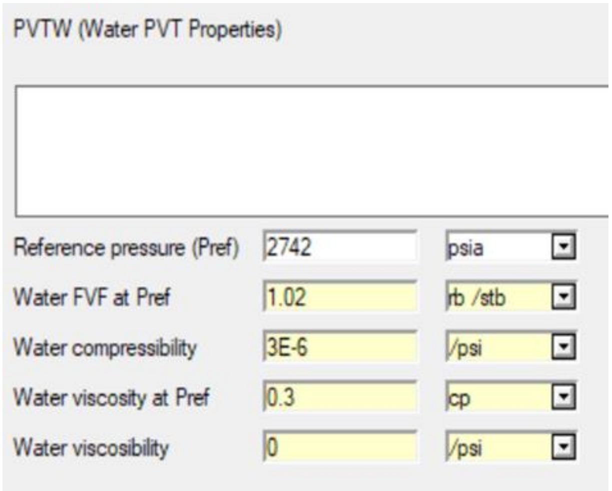

Figure 3.13: PVTW input data

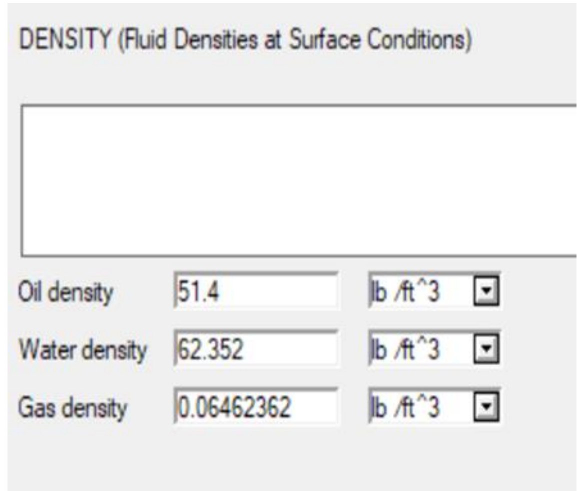

Figure 3.14: PVTO input data

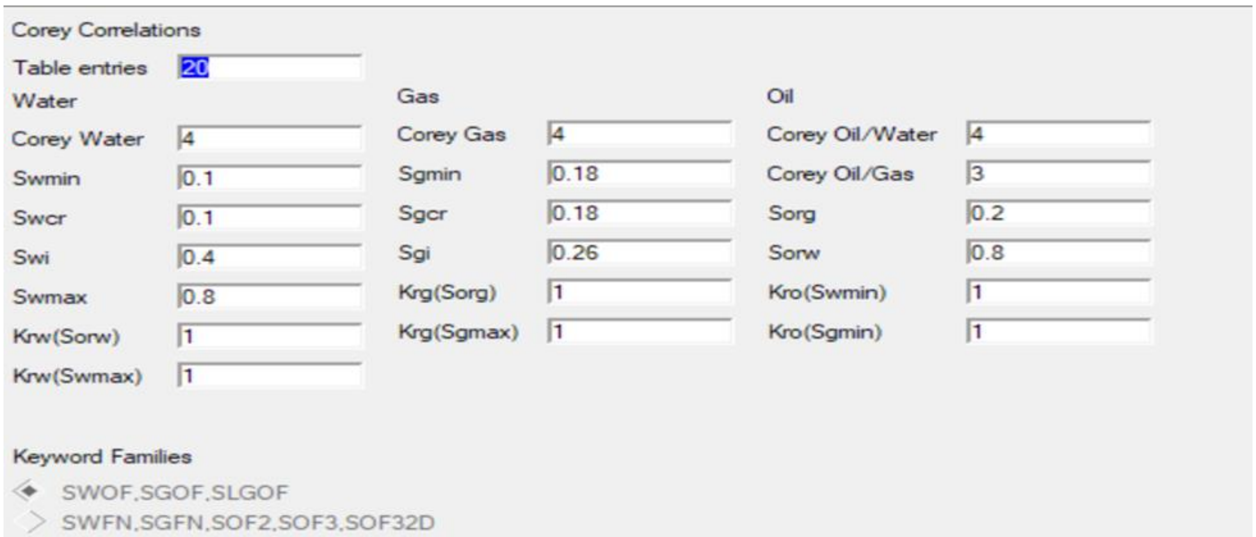

Figure 3.15: Corey input data

3.3.2 Basic Case Simulation

After model initialization, the base case model was simulated. First, an aquifer model was attached to the reservoir. The properties of the Carter-Tracy aquifer are listed in Table 3.3.

Table 3.3: Aquifer Properties

ITEM	VALUE	UNIT
Number of aquifers	1	dimensionless
Datum depth	5600	feet
Pressure	2870	psia
Permeability	800	mD
Porosity	29	%
Rock compressibility	$1.8e^{-5}$	1/psia
External radius	3600	feet
Net thickness	90	feet
Aquifer encroachment angle	180	degree

In addition, the following assumptions and constraints were established to evaluate the performance over a 15-year period, i.e., forecasting production:

- Well Economic limit of 150 STB/D and 100 MSCF per well.
- Water cut of 80% per well.
- A maximum solution gas-oil-ratio of 5 MSCF/STB

Aquifer was incorporated into the edges of the reservoir model of the base case to simulate the pressure support in the model.

3.3.3 Wells Design

A well design application was used to develop an optimum rate and tubing size for infill wells to be drilled in the Ratson field. It simulates, analyzes, and optimizes the production performance of oil and gas wells. Assumptions and constraints for PVT and pressure data used in the well design are shown in Table 3.4.

Table 3.4: Reservoir Data and Well design Constraints

TYPE	**VALUE**
Reservoir Pressure, Psia	2870
Wellhead Pressure,	300
Reservoir Temperature, ^{o}F	160
IPR, Basic	Liquid
IPR Model	Vogel
Water cut, %	0
GOR, scf/stb	850
Gas Specific Gravity	0.85
Water Specific Gravity	1
API	40^{o} API
Fluid	Oil + Water
Completion Type	Cased Hole
Sand Control/Production	No
Gas Coning	No
Flow Type	Tubing
Tubing size	3.5”

The Inflow Performance Relationship (IPR) curve is used to assess well performance by plotting well production rate against the flowing bottomhole pressure. Figure 3.16 shows a typical IPR curve.

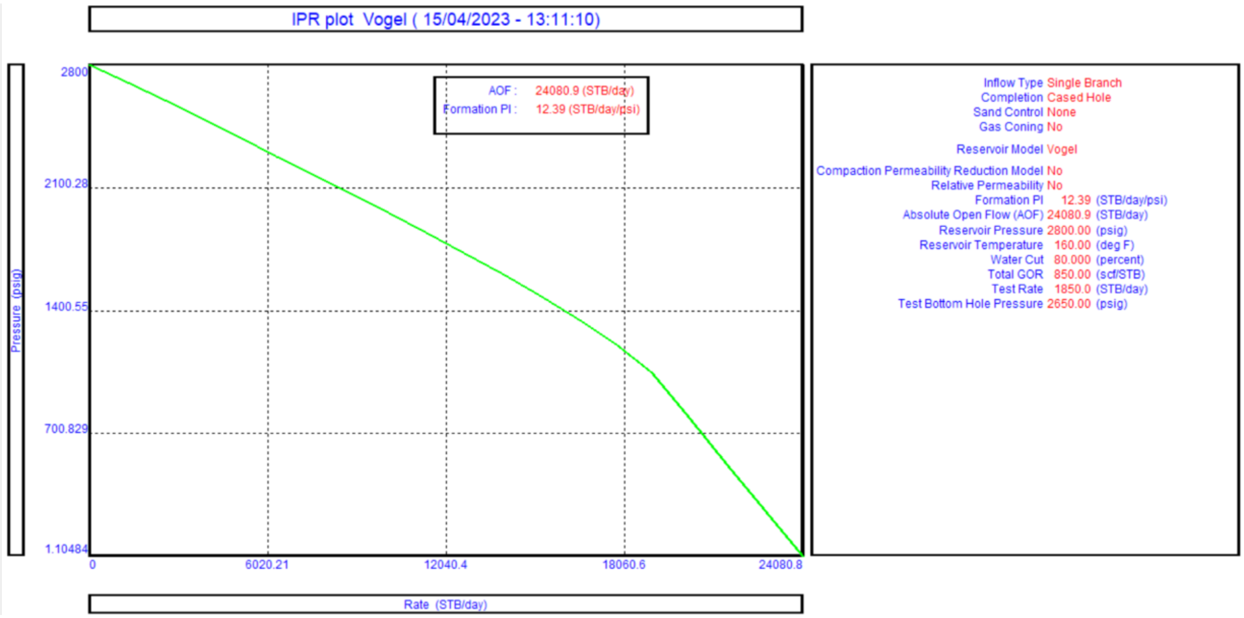

Figure 3.16: Typical IPR curve

It is important to note that the reservoir fluid composition and fluid phases determine the shape of the curve. Nonetheless, to determine the optimal production rate and tubing size for designing infill wells, the solution point is obtained by the intersection of an (IPR) curve and a Vertical Flow Performance (VFP) curve. This approach allows for the identification of the production rate that maximizes well performance and facilitates the optimal design of infill wells. Figure 3.17 shows the inflow performance curves for the base case with the relevant parameters defined in the study.

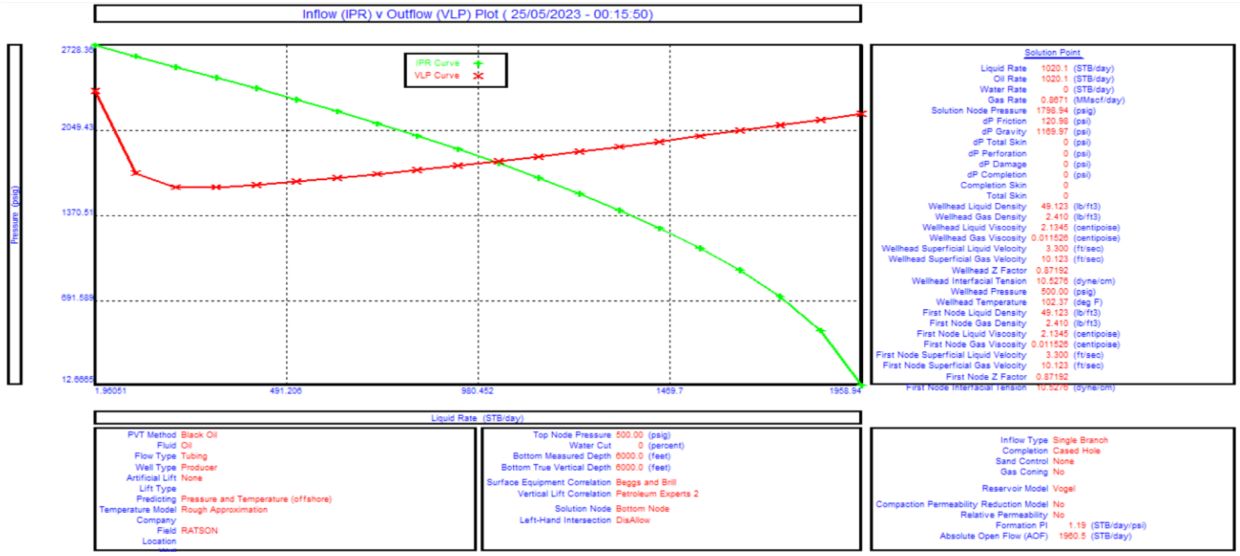

Figure 3.17: Typical IPR and VFP curve

3.3.4 Basic Case Simulation Production Strategy and Sensitivity Analysis

Tubing size and production rate are crucial factors for optimizing production from wells draining a reservoir or field. A sensitivity analysis was conducted on Ratson Sand C to examine how production is influenced by variations in tubing head pressure (THP) and the injection rates of the recovered natural gas. This strategy aimed to achieve optimal production performance while ensuring compliance with operational, economic, and environmental requirements. Oilfield visualization application, ResInsight, an open-source application utilized in the oil and gas industry for reservoir visualization and interpretation (ResInsight, 2023), is utilized to select well locations and determine the optimal completion interval in order to mitigate gas coning, water coning or excessive liquid production.

Using the well design software, a vertical lift performance analysis was conducted without any gas injection as the base case. This base case was then used as a reference for simulation runs and subsequent sensitivity analyses. The sensitivity analysis included using different gas injection rates of 250MSCF/D, 500MSCF/D, and 1MMSCF/D of the recovered gas, along with

THPs of 200, 250, and 350 psia as the varying parameters. The objective was to assess the cumulative hydrocarbon production under these different conditions. These analyses were conducted in the study to evaluate the impact of varying injection rates and THPs on the overall production performance of the Ratson field. This information would provide valuable insights for optimizing hydrocarbon production of the field.

3.3.5 Decline Curve Analysis

Decline Curve Analysis (DCA) using the Arps equations was performed for a production period consistent with that of the simulator (i.e., 15 years). Decline curve analysis (DCA) utilizes historical production data to estimate the future production performance of a reservoir. By analyzing decline curves, it becomes possible to identify underperforming or non-economic wells, optimize production strategies, and assess the effectiveness of production enhancement techniques. Utilizing this approach, DCA can provide estimates of recoverable reserves. Even in high permeability reservoirs like the Ratson field, the decline curve method is effective with limited production data. The exponential equation commonly used in such cases is as follows:

$$q = q_0 e^{-at} \quad \text{......(3.3)}$$

where a is the (constant) instantaneous decline factor, q is the flow rate at time, t, and q_0 is the initial flow rate. The reserves from the DCA and dynamic simulation were used in an economic analysis. Input parameters for Excel template for the DCA are summarized in Table 3.5.

Table 3.5: DCA Parameters and Constraints

DCA PARAMETERS/CONSTRAINTS	**VALUE**
Maximum no of wells	2
OIIP from dynamic simulation	27.2 MMSTB
Recovery factor	25%

Plateau period	4 years
Plateau rate per well	1600 STB/D
Abandonment rate/econ limit	150 STB/D
Efficiency factor	1 (100%)
Water cut limit	80%
Condensate Gas Ratio (CGR)	0
Solution gas-oil-ratio	850 SCF/STB
Decline exponent was considered in months	30 days

3.3.6 Economic Analysis

An economic analysis was conducted in this study. The objective of the evaluation was to assess the financial aspects of the production strategies proposed for developing the Ratson field and ascertain their profitability. The major input data are the reserves generated by decline-curve analysis (DCA) and the simulator. The economic analysis considered the CAPEX (capital expenditure), OPEX (operating expenditure), taxation, petroleum profit tax, and royalties. The fiscal regime was based on Regulation 2 of the Marginal Fields Operations (Fiscal Regime) Regulations, 2005. The 2005 regulations outline the categories of royalties payable to the government based on the level of production carried out in the marginal fields (Komolafe, 2020). Profitability indicators such as NPV (net present value), Internal Rate of Return (IRR), Profitability Index (PI), and Break-Even Price were employed as measures to assess the viability of the production strategies considered for the Ratson field. Other assumptions and constraints for this analysis include:

- Capital cost of $10 million
- Operating cost of $10/barrel and $12/barrel with gas injection

- Oil price of $70/barrel
- Gas price of $3/MCF
- Abandonment cost of 15% CAPEX

3.3.7 Environmental and Risk Analysis

This analysis involves mapping out the potential risks and uncertainties associated with subsurface and surface development. It includes their likelihood of occurrence, and their potential impact on the project or decision outcomes. An integrated approach of identifying risks with a subsurface root, risk ranking matrix, linking risk to key subsurface uncertainties and surface uncertainties, assess impact of these uncertainties and developing an activity plan (mitigation plan) are all adopted for this analysis.

The results derived from the outlined methodology of this research are presented in the subsequent chapter (Chapter 4).

Chapter 4: Results and Discussions

This chapter presents the results obtained from this study. The results are carefully documented and thoroughly discussed in sections. Volumetrics from both Static Modelling and model initialization of the Ratson Field are presented. A comparative study, evaluating the performance of different production strategies defined by sensitivity analysis is evaluated.

4.1 Volume Estimates from Static Modelling

The volumes of Gas Initially In Place (GIIP) and Stock Tank Oil Initially In Place (STOIIP) were determined as discussed in the Chapter on study methodology. and are presented in Table 4.1. These calculations were performed for all sands identified within the Ratson field using the data from the static models.

Table 4.1: Static Volumetrics of Ratson Field

Reservoir	**Fluid**	**GRV (acre-ft)**	**NTG**	**PHI (fraction)**	**Shc (fraction)**	**FVF**	**OIIP (MMSTB)**	**GIIP (BSCF)**
A	Gas	3311	1	0.32	0.84	0.004	0	9.7
B	Gas	3892	0.9	0.33	0.83	0.004	0	10.4
C	Gas	10483	0.97	0.38	0.81	0.004	0	34.1
C	Oil	16470	0.97	0.37	0.71	1.4	23.3	0
D	Gas	2134	0.9	0.49	0.78	0.004	0	8.0

It is noteworthy that Ratson Sand C, which is the primary focus of this research work, contains over 95% of total hydrocarbons from the four sands in the Ratson field.

4.2 Dynamic Modelling for Reserves Estimation

4.2.1 Model Initialization

Figures 4.1 – 4.4 show the North, South, West, and East views of the Ratson field model after initialization. It is important to note that these results were visualized using ResInsight (ResInsight, 2023).

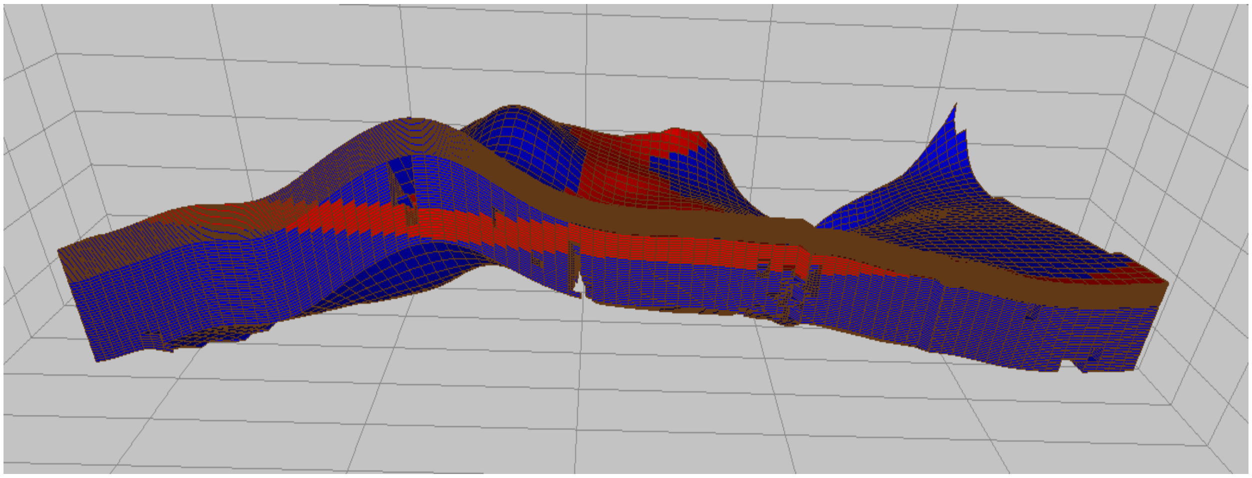

Figure 4.1: 3D view of the Ratson field – North view

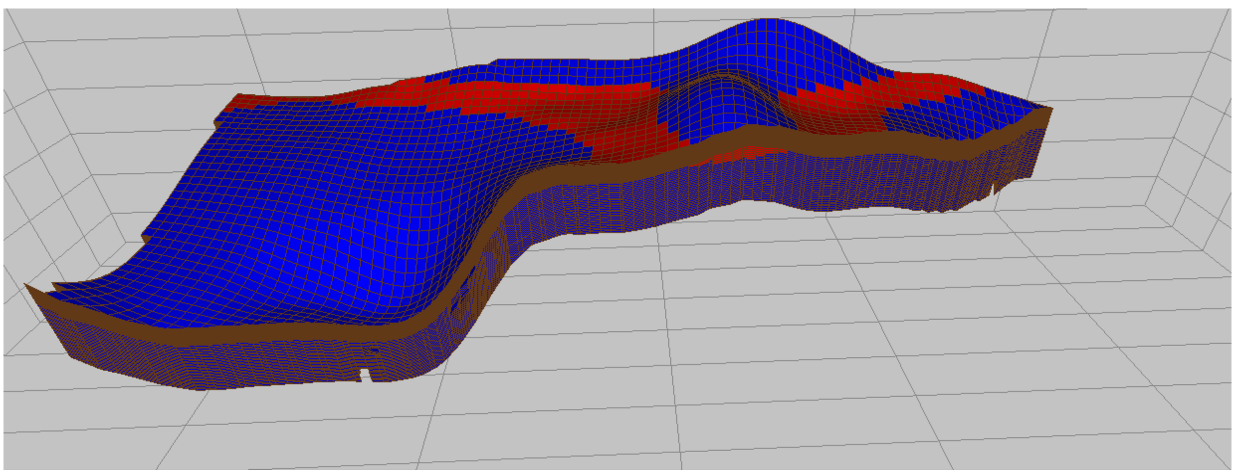

Figure 4.2: 3D view of the Ratson field – South view

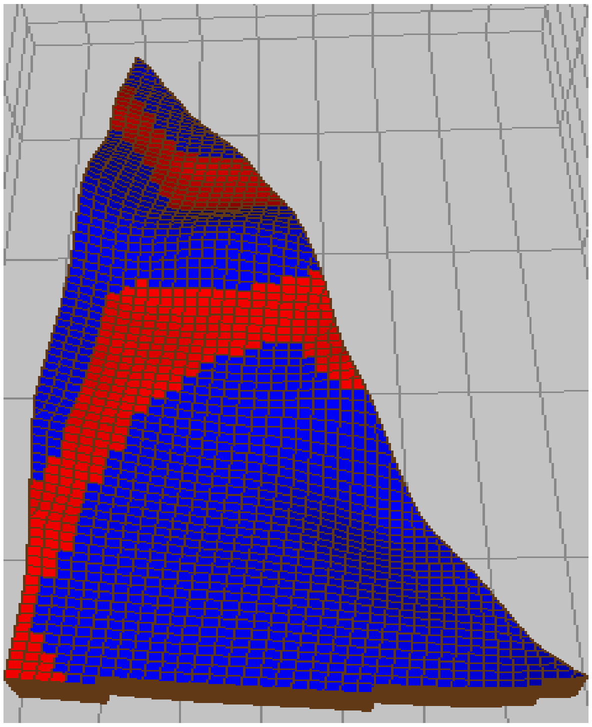

Figure 4.3c: 3D view of the Ratson field – West view

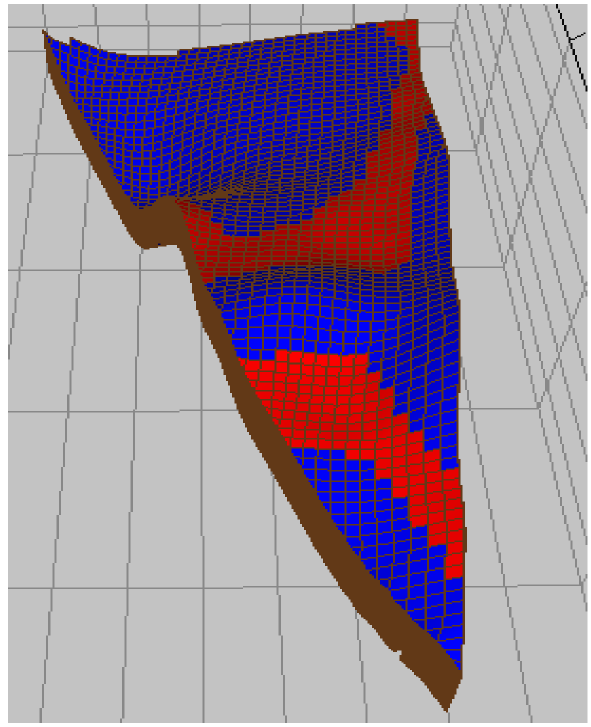

Figure 4.4: 3D view of the Ratson field – East view

Based on analysis of the 3D reservoir models, the presence of oil saturation in Sand C is clearly visible. The red grids indicate areas with high oil saturation, while the blue areas represent locations with water. Figure 4.5 further shows results of the behavior of reservoir pressures and saturations after the model initialization was run for a period of 15 years.

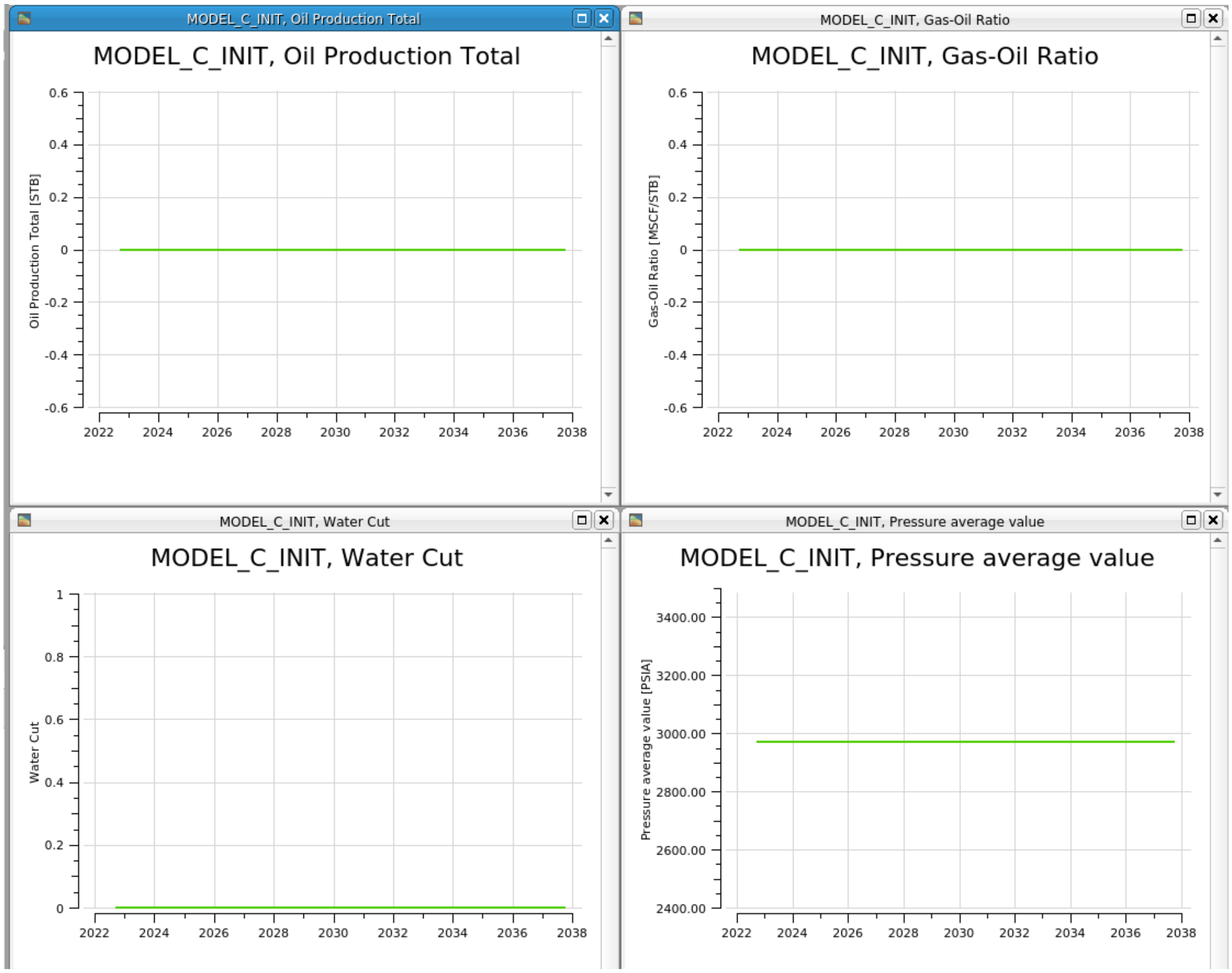

Figure 4.5: Results of Sand C Model Initialization after 15-year simulation

The GIIP and STOIIP obtained from the model initialization, alongside the absolute difference between the static and dynamic models are documented in Table 4.2. The Absolute Percent Difference is calculated as:

$$\frac{(Dynamic\ Volume - \ Static\ volume)}{Static\ volume} \times 100 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4.1)$$

Table 4.2: Static and Dynamic Volumetrics of Ratson Field

		STATIC VOLUMETRICS		**SIMULATOR MODEL INITIALIZATION**		**ABSOLUTE DIFFERENCE BETWEEN STATIC AND DYNAMIC MODELLING**	
Reservoir	Fluid	STOIIP (MMSTB)	GIIP (BSCF)	STOIIP (MMSTB)	GIIP (BSCF)	STOIIP (%)	GIIP (%)
A	Gas	0	9.7	0	6.8	0	30%
B	Gas	0	10.4	0	7.1	0	32%
C	Gas	0	34.1	0	28.4	0	17%
C	Oil	23.3	0	27.2	0	-17%	0%
D	Gas	0	8	0	7.3	0	9%

With the model initialized, a realistic starting point for evaluating the reservoir's performance over a specified time frame was established. Consequently, this provided valuable insights for determining the optimum production strategy and making informed decisions regarding reservoir management and development plans.

4.2.2 Wells Design

Dynamic simulation results provide valuable insights for determining the optimal placement of wells to maximize hydrocarbon recovery, specifically focusing on oil recovery in this case. The well-design software was used in generating the IPR curves and VFP using data shown earlier in Table 3.2. The analysis employed the Vogel IPR equation, which is commonly used to analyze and optimize production performance in oil and gas reservoirs. It helps us in understanding the relationship between production rate and bottomhole pressure, and it assists in optimizing well production and designing artificial lift systems such as pumps or gas lift.

The productivity index (PI) is calculated by dividing the well's flow rate by the pressure drawdown. Mathematically, the PI is defined as,

$$PI = \frac{(Well\ Flow\ rate)}{Pressure\ Drop} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(4.2)$$

The PI represents the relationship between the flow rate of the well and the pressure drop across the reservoir. A higher productivity index indicates a more efficient well, capable of delivering larger volumes of fluid at a given pressure drawdown.

The IPR calculation is derived from a single flowing bottomhole pressure and a given surface test rate. Figure 4.6 illustrates the base case IPR curve, which yields a formation productivity index of 1.19 (STB/D/psi) and an absolute open flow (AOF) of 1960.5 (STB/D). The Productivity Index (PI) is a measure of a well in terms of fluid production in relationship to the production in relation to the amount of energy that is supplied to the reservoir.

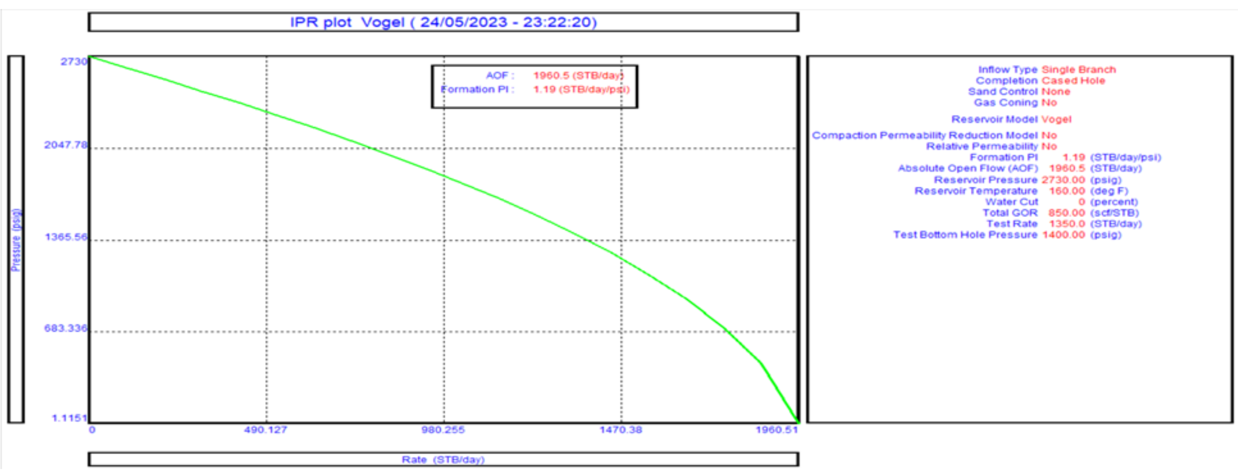

Figure 4.6: Base Case IPR Curve

A sensitivity analysis was performed starting from the base case IPR curve by adjusting the pressure range from 2730 to 1000 psia, as illustrated in Figure 4.7. The analysis revealed that the absolute open flow (AOF) exhibited a decreasing trend, declining from 1960.5 to 662.9 psi. This indicates a significant sensitivity to reservoir pressure changes. Additionally, the presence of water cut was considered in Figure 4.8, which resulted in an increase in AOF. Specifically, the AOF increased from 1960.5 STB/D with 0% water cut to 2365.8 STB/D at the economic limit of 80% water cut. These findings highlight the impact of reservoir pressure and water cut on the AOF and emphasize their importance in determining the optimum production performance and economic viability of the well.

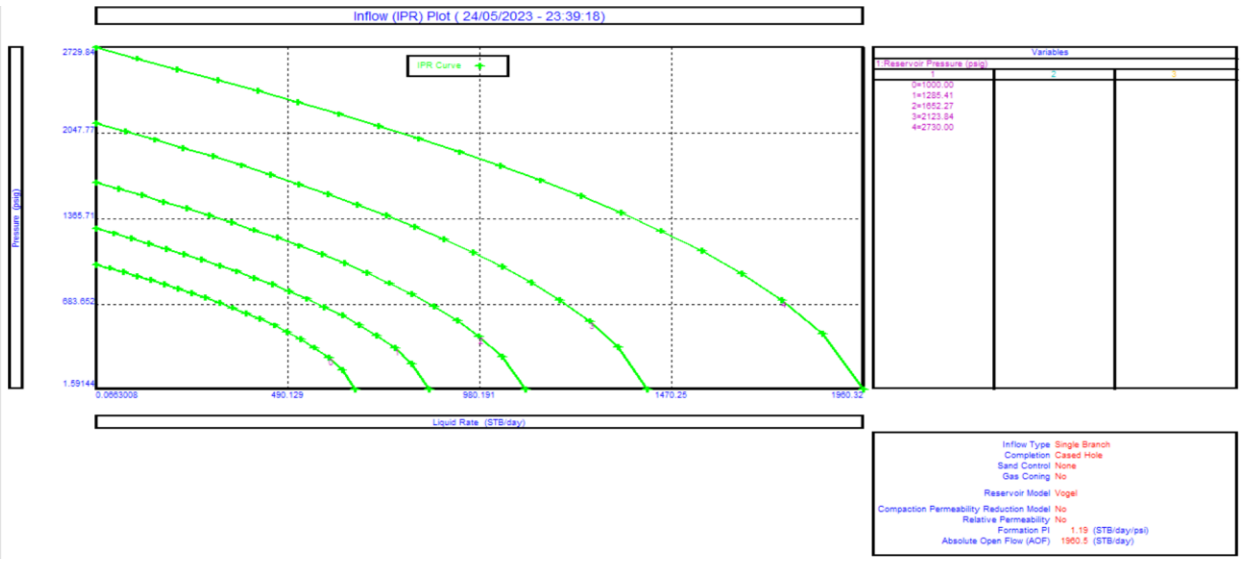

Figure 4.7: IPR Curve of Ratson Sand C with Pressure Sensitivity

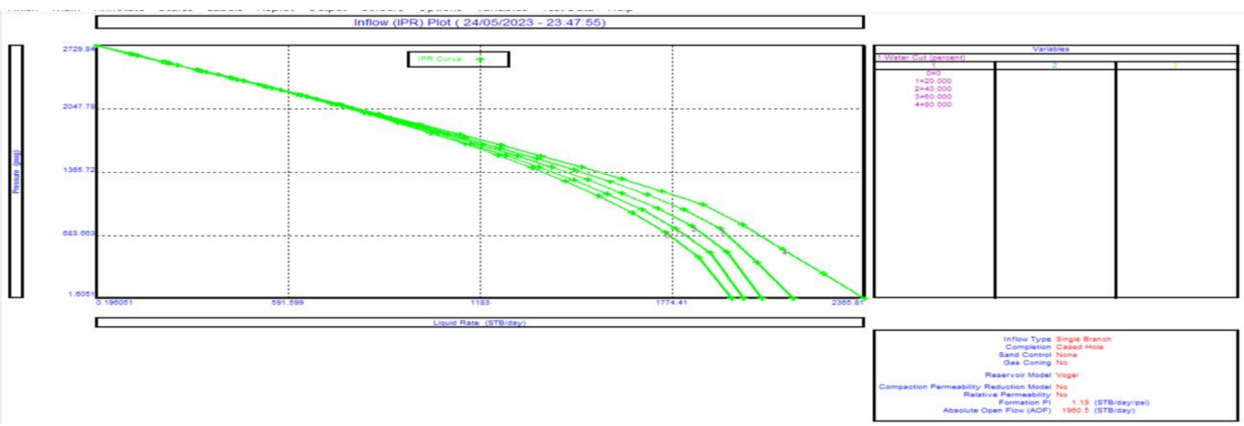

Figure 4.8: IPR Curve of Ratson Sand C with Water Sensitivity

The utilization of the operating point, derived from the intersection of the IPR and VLP curves, facilitated the estimation of key parameters including the wellbore flowing pressure and fluid rates.

Specifically, wellbore fluid rates of 1020.1 STB/D and 0.8761 MMSCF/D as seen in Figure 4.9 were recorded. This established model was subsequently employed for further analysis in defining production strategies, i.e., THP and Injection rate sensitivity.

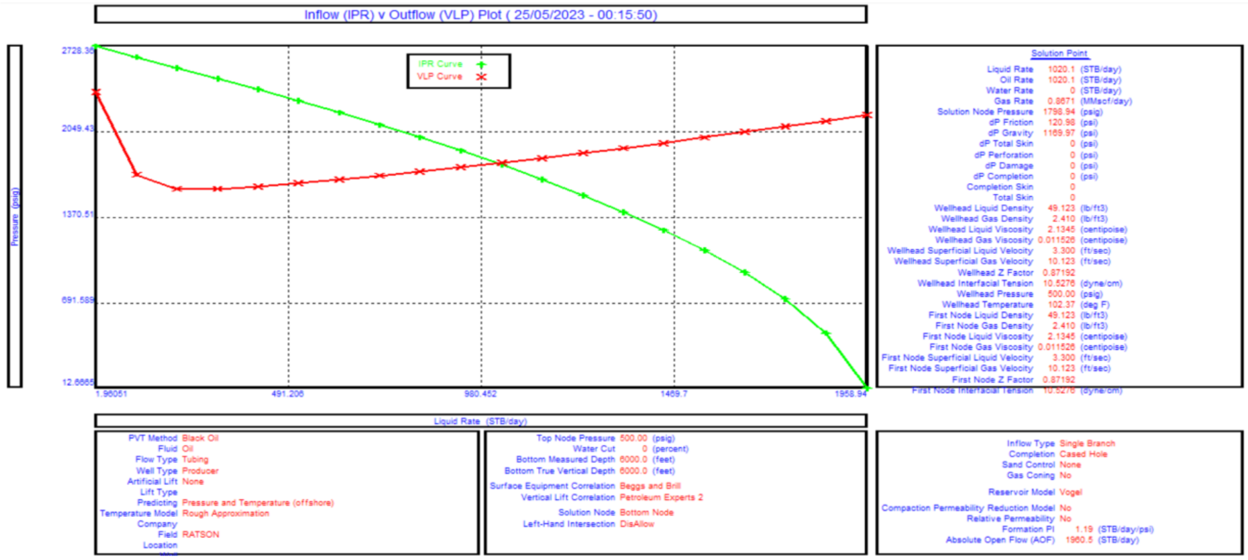

Figure 4.9: IPR/VLP Intersection Point.

Figure 4.10 depicts the placement of the two wells in the model, considering the results obtained from the well design. It is important to note that a maximum of two wells were considered due to Ratson field being a marginal field. The performance of these wells will be discussed in the next section. First, we analyze the base case production strategy where production relies solely on the natural drive of the wells in optimized locations.

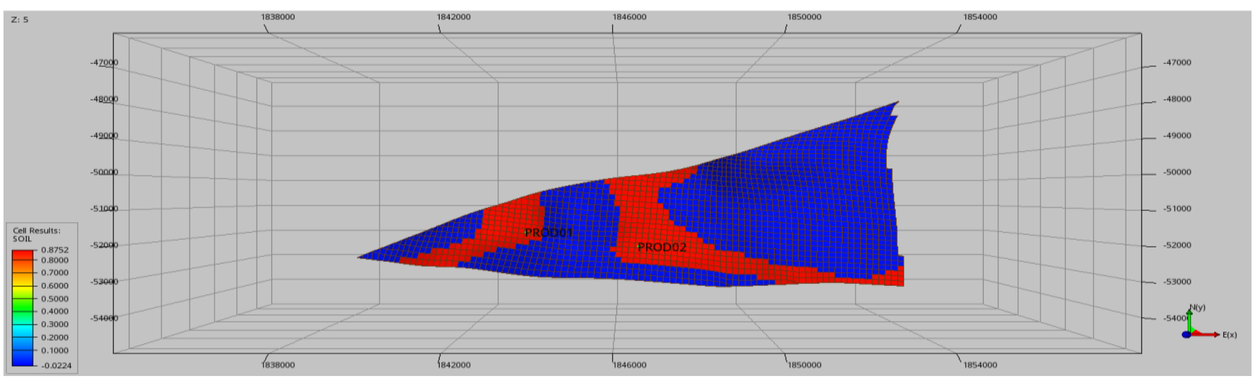

Figure 4.10: Location of Wells in Model

4.2.3 Sand C Base Case Results

The result from the well design informed by the optimization well application was incorporated into the simulator app, which acts as the base case for this research work. The base case includes a production rate of 1020 STB/D, a tubing size of 2 inches, and a tubing head pressure (THP) of 500. Table 4.3 and Figures 4.11 present the cumulative oil produced, cumulative gas produced, time for wells to reach maximum water cut, and maximum gas oil ratio recorded from the simulator application.

Table 4.3: Base Case Production Rates

	Cumulative Oil Produced (STB)	Cumulative Gas Produced (BSCF)	Time To Max. Cumulative Water Produced	Max Cumulative Field Gas-Oil Ratio (MSCF/STB)
BASE CASE	6.4	11	July 2036	2.1

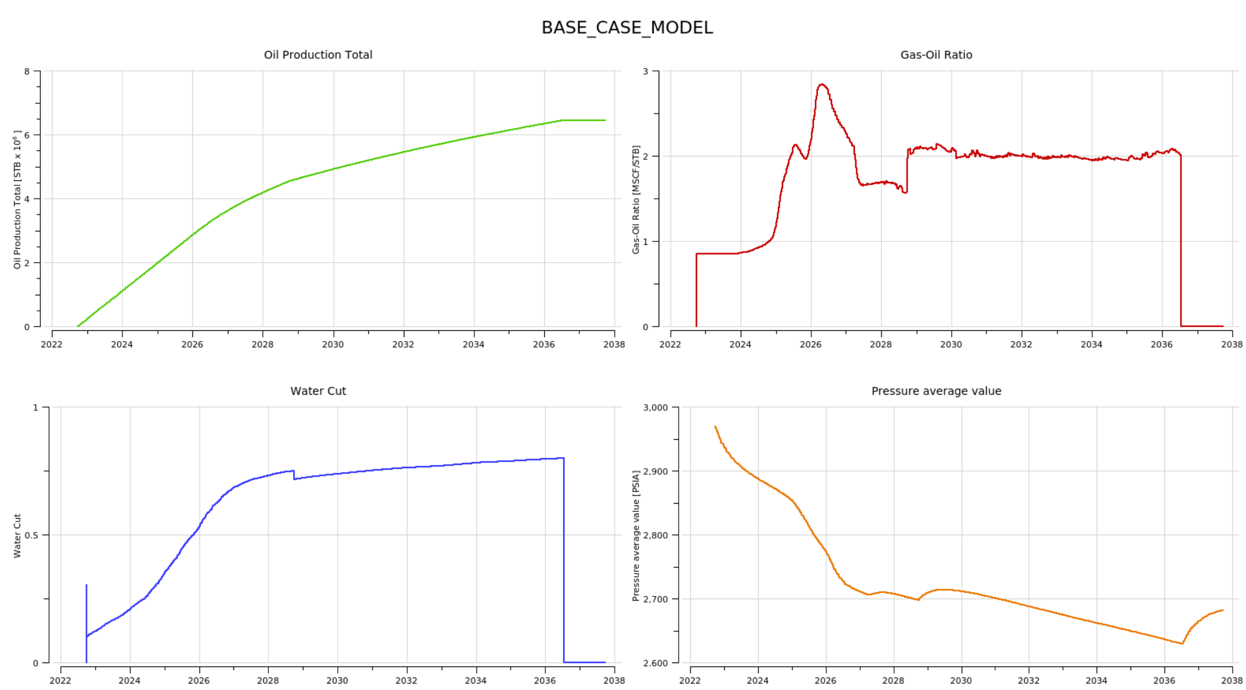

Figure 4.11: Base case cumulative production

Based on the data in Figure 4.11, it is observed that cumulative oil production reached its peak before a shut-in occurred due to water cut in July 2036. Primary oil production was sustained for approximately 15 years. The gas production rate and solution gas-oil ratio were effectively controlled by the production tubing and maintained at a defined production rate. The reservoir performance of the base case is considered both feasible and desirable.

4.2.4 THP and Gas Injection Rate Sensitivity

The sensitivity analysis carried out focused on tubing head pressures (THP) and gas injection rates. THP values considered in the simulator application were 200, 250, and 300 psia, as well as gas injection rates of 250 MSCF/D, 500 MSCF/D, and 1 MMSCF/D for pressure maintenance. The results of the sensitivity analysis are shown in Table 4.4.

Table 4.4: THP and Injection Sensitivity Production Rates

Case	Cumulative Oil Produced (MMSTB)	Cumulative Gas Produced (BSCF)	Time To Max. Cumulative Water Produced	Max Cumulative Field Gas-Oil Ratio (MSCF/STB)
THP CASE				
200 PSIA	5.6	10.4	July 2032	2.9
250 PSIA	5.9	11.0	October 2033	2.9
350 PSIA	6.1	10.4	September 2034	2.8
Base Case	**6.4**	**11**	**July 2036**	**2.1**
INJECTION CASE				
250 MSCF/D	6.6	10.3	May 3037	2.6
500 MSCF/D	6.5	10.4	March 2037	2.6

1000 MSCF/D	6.5	10.3	January 2037	2.5
Base Case	**6.4**	**11**	**July 2036**	**2.1**

Furthermore, Figures 4.12 and 4.13 show graphical plots of the results. They include the cumulative oil produced, gas-oil ratio, water cut, and average pressure. The data shows a comparison of the base case and the results from the THP sensitivity and injection rates sensitivity analysis.

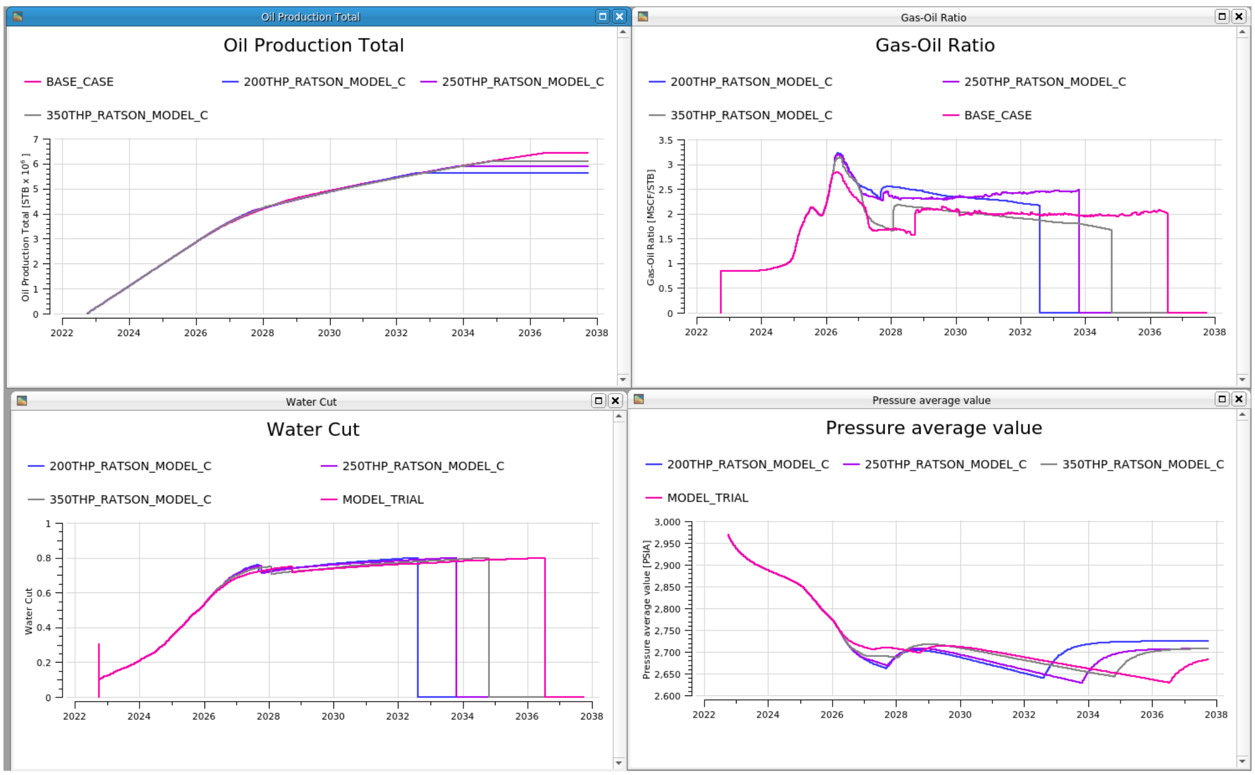

Figure 4.12: THP Sensitivity Plots

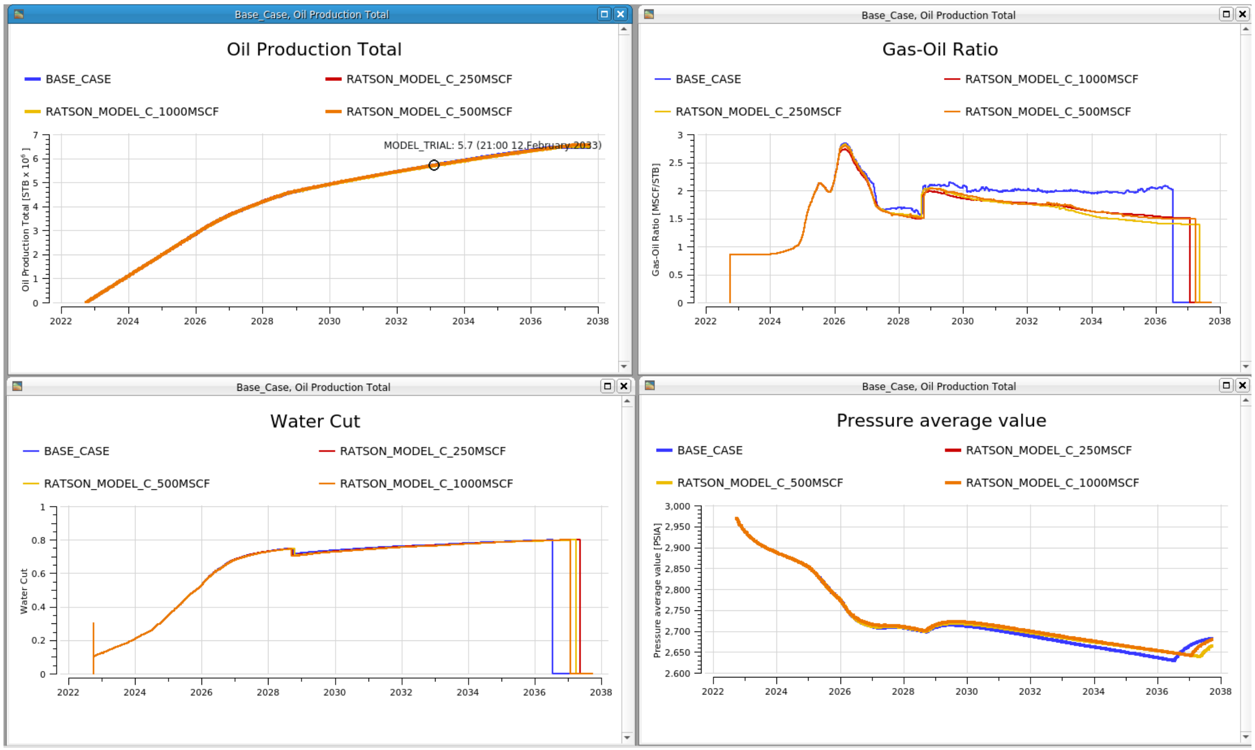

Figure 4.13: Gas Injection Rates Sensitivity Plots

The cumulative oil produced from all tubing head pressures considered are all lower than that of the base case scenario of 500 THP. The impact of THP on production can be understood through its effect on the flowing bottomhole pressure (FBHP). FBHP is the pressure at the bottom of the wellbore, where the reservoir fluids flow into the wellbore and up to the surface. It is also a critical parameter in well production and control. The choice to increase or lower it depends on the specific goals and conditions of the well, such as maintaining production rates, controlling gas behavior, and managing reservoir performance. Proper management of FBHP and ultimately THP is essential to optimize the performance and longevity of oil and gas wells.

Additionally, from the results of Figures 4.12 and 4.13, it is evident that employing natural gas injection as a production strategy in Ratson Field C has yielded slightly more recovery than the base case. While gas injection remains a valuable technique for maximizing production and optimizing hydrocarbon recovery in oil and gas fields, the results for the Sand C show marginal improvements in recovery. They do not justify the economics of operating a gas injection program in this case.

Furthermore, results obtained from injecting the recovered gas at rates of 500 MSCF and 1000 MSCF yielded the same oil recovery of 6.5 MMSTB which is slightly lower than that of 6.6 MMSTB gotten from injecting 250 MSCF of recovered gas. However, it should be noted that injecting 1000 MSCF of gas leads to the shutting down of the well 2 months earlier compared to the injection scenario of 250MSCF and 500 MSCF due to the terminal water cut of 80%. From the study results, it is recommended to employ an injection rate of 250 MSCF as this case yielded an oil recovery of 6.6 MMSTB and sustained oil production longer before reaching the terminal water-cut, when compared to other injection cases. This is a major finding from this study.

4.2.5 DCA for Estimating Reserves

By analyzing the decline curve, it becomes possible to identify the performance of the defined number of wells that are economical, optimize production rates, and assess the effectiveness of production enhancement techniques or the recovery factor of the field. From the DCA performed, the total life of the reserves of the static volumetric stood at 14.84 years; 4 years of plateau production and 10.84 years to abandonment. This goes to say that two wells are optimal for the production of Ratson field. Figure 4.14 provides a graphical representation of the relationship between production rate and time in years. Note that the exponential decline model stands at 47% per year. This high decline rate was done to align the economic limit and life of the reserves to those obtained from the simulation. In practice, the DCA would have to be projected using a more realistic decline rate to get a longer life of the reserves.

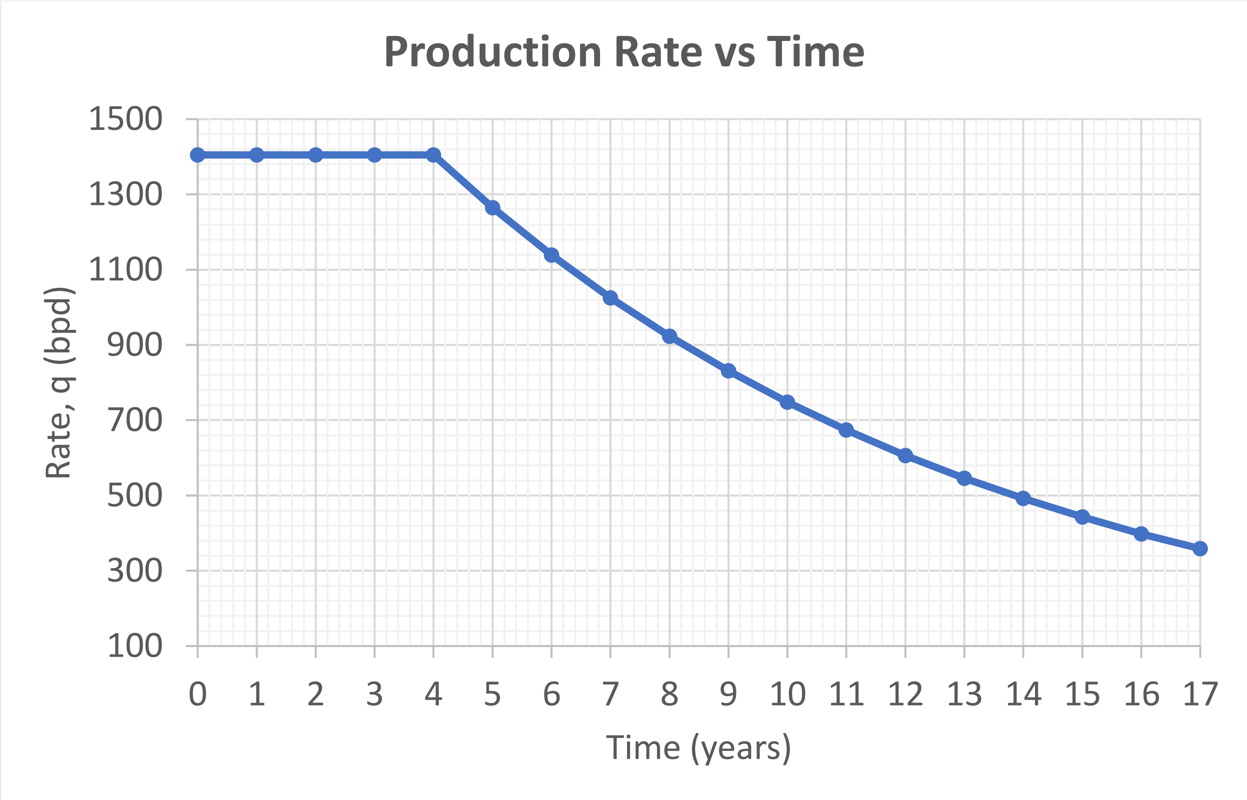

Figure 4.14: Oil Rate vs Time

The future production rates derived from the decline analysis are depicted in Figures 4.15. The results shown in Figure 4.16 are obtained from the simulator. The cumulative oil production from Sand C of the Ratson field amounted to 10.97 MMSTB from DCA and 6.4 MMSTB from the simulator over the 15-year life of the field.

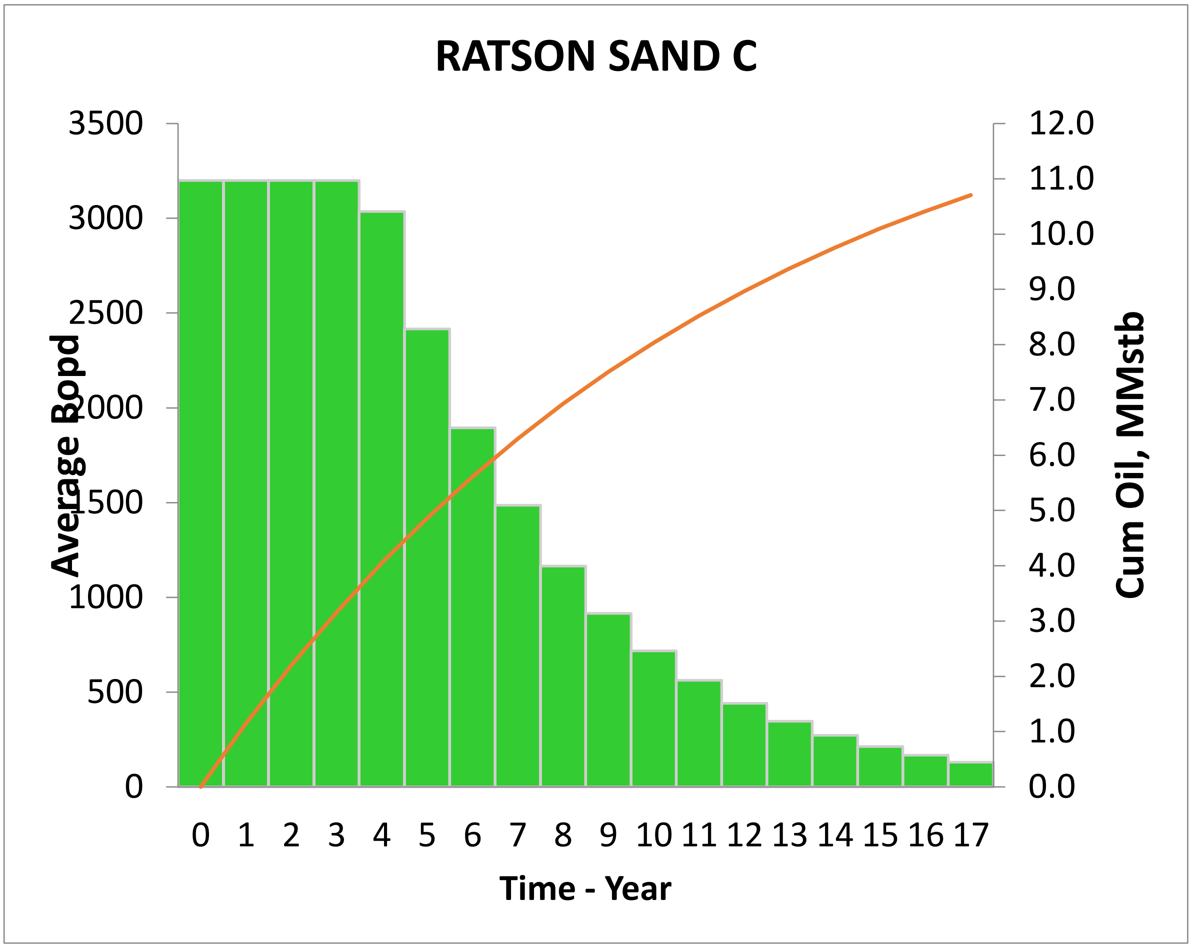

Figure 4.15: DCA Annual Reserves Production Performance

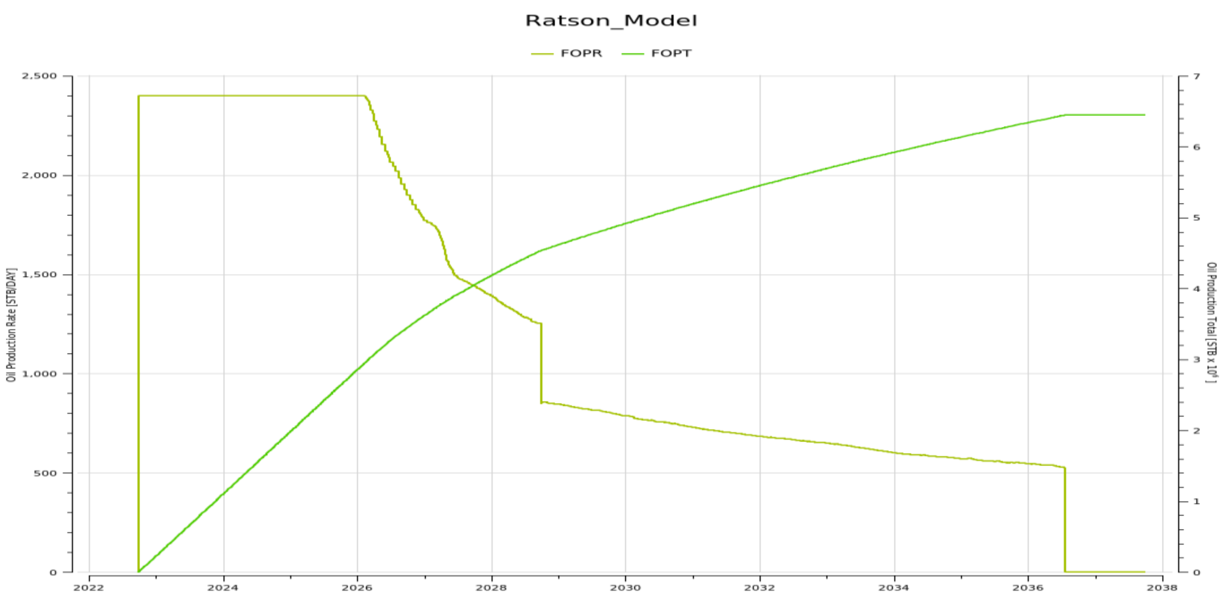

Figure 4.16: Annual Reserves from Simulation of Sand C Production

Table 4.5 shows a comparison on DCA and simulator annual production rates and the percent deviation. Mathematically. Percent difference is calculated as;

$$Percent\ Difference\ =\ \frac{Difference\ between\ values}{Simulator} \times 100 \ldots\ldots\ldots\ldots\ldots\ldots \quad (4.2)$$

Table 4.5: Annual Reserve Performance

Year	DCA (STB/YR)	Simulator (STB/YR)	Percent Difference
2022	3200.0	2400	25%
2023	3200.0	2400.0	25%
2024	3200.0	2400.0	25%
2025	3200.0	2400.0	25%
2026	3036.4	2095.6	31%
2027	2416.2	1546.0	36%
2028	1895.4	1192.8	37%
2029	1486.6	816.7	45%
2030	1165.8	757.5	35%
2031	914.6	705.3	23%
2032	717.2	666.2	7%
2033	562.4	626.1	11%
2034	441.0	585.9	33%
2035	346.0	558.4	61%
2037	271.4	294.5	9%
2038	212.8	0.0	100%

From these results, it is important to note that although DCA assumptions were carefully considered and validated based on the specific reservoir characteristics and neighboring fields, the

DCA reserves are constantly higher than those from the simulator. It is crucial to acknowledge that DCA should always be used in conjunction with other reservoir engineering tools and data sources to ensure accurate analysis and interpretation. DCA results tend to be overly optimistic compared to the reservoir simulation performance. This underscores the need to carry out reservoir simulation to validate the recovery factors obtained from DCA during field development planning. The proposed simulation framework discussed in this study is the key to achieving this FDP objective.

4.2.6 Environment/Risk Analysis

An integrated approach was employed to analyze uncertainties and associated risks, both from the subsurface and surface aspects of the field development. The focus of this approach was to comprehensively consider all aspects of field development planning to ensure a holistic understanding of the Ratson field development project as much as possible.

The findings of this project risk analysis are presented in Table 4.6. The table highlights the key uncertainties, their corresponding risks and it identifies the ways to mitigate the risks.

Table 4.6: Ratson Sand C Project Uncertainties, Risks and Mitigation

S/N	Uncertainty	Risk	Chance of Occurrence	Impact	Mitigation Techniques
1	Fluids contacts	▪ Under/over estimation of hydrocarbon in place ▪ Early water breakthrough ▪ Thief zone	High	Medium	• QC logs • QC models
2	Reservoir structure	▪ Under/over estimation of hydrocarbon in place ▪ Wrong placement of well	Medium	Medium	• QC models • Integrated data analysis
3	Reservoir Continuity	▪ Well planning ▪ Recovery Efficiency ▪ Water/gas breakthrough	Medium	Low	• QC models • History matching
4	Aquifer strength	▪ Pressure decline ▪ Hydrocarbon recovery	Low	Medium	• Analytical and numerical modeling

					• Well Interference Analysis
5	Fluid properties	▪ Surface facilities design ▪ Flow assurance ▪ Artificial lift requirements	Medium	High	• QC PVT reports • Calibration with field data
6	Reservoir pressure	▪ Recovery efficiency ▪ Drilling risks	Medium	High	• QC laboratory procedures and tools used in estimating pressure
7	Operational and Technical	▪ Facility damage ▪ Loss of human lives	Low	High	• QC daily activities
8	Weather and Climate	▪ Downtime ▪ Increase costs	Medium	High	• Weather Monitoring and Forecasting • Safety Training and Awareness
9	Regulatory and compliance	▪ Penalties ▪ Legal issues	Low	High	• Up to par with government or regulatory information channel • External expertise and Legal counselling
10	Political and geopolitical policies	▪ Project stability ▪ Long-term investments	Low	High	• Engage in Stakeholder Communication • Foster a culture of compliance

A risk matrix shown in Figure 4.17 is a similitude of what is used in the industry to emphasize and manage efficiently the severity of risks attached to a project. By plotting risks on the risk matrix grid (Figure 4.17), reservoir and production engineers can visually assess and prioritize risks based on their location in the matrix grid. Typically, risks falling in the high likelihood and high impact quadrant are considered the highest priority, requiring immediate action and robust risk management measures. Conversely, risks falling in the low likelihood and low impact quadrant are considered lower priority and may not require significant attention. Hence, uncertainty Nos. 1 and 3 necessitate the implementation of a contingency plan, while uncertainty Nos. 4, 5, and 6, are considered to be mitigated by routine safety barriers due to their low probability of occurrence. Note uncertainty Nos. 2, 7, 8, 9, and 10 require immediate attention to both prevent and lessen both their likelihood and potential impact.

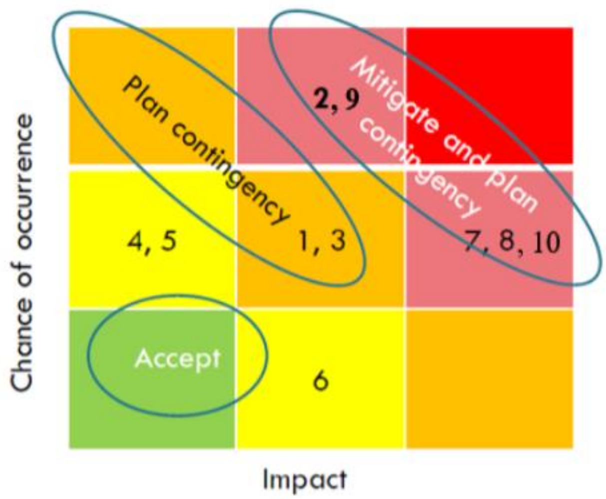

Figure 4.17: Risk Matrix of Developing Snad C of the Ratson Field

4.2.7 Economic Analysis

The results of the economic analysis are discussed in the following section. The analysis was based on the assumptions, data and constraints defined earlier in this study. Profitability indicators such as NPV, IRR, PI, and Break-Even Price obtained from the results of this analysis are documented in Table 4.7. It is important to note that profitability indicators do not have a set rule and are best defined or interpreted by the investors. NPV is commonly the first major tool in determining the value of any oil and gas project as it is used to assess the profitability of an investment or project. On the other hand, the IRR provides insight into the potential profitability and efficiency of an investment by considering the timing and magnitude of cash flows. It helps to determine the rate at which the investment will generate a return on the initial investment. Furthermore, the PI considered for this analysis is calculated by dividing the present value of cash inflows by the present value of cash outflows, thereby determining the ratio of the present value of expected future cash flows to the initial investment cost. Additionally, the Break-Even Price indicates the point at which capital costs have been fully recovered. By analyzing the break-even price, petroleum economists and investors can make informed decisions about the profitability of the project.

Table 4.7: Economic Analysis Parameters

NPV	429.0	MM$
IRR	15.6	%
PI	0.16	%
Break Even Price	1.1	MM$

Note, the economics analysis considered was based on the reserves derived from the simulator. It is important to communicate however, that these values are assumed to be specific and advantageous to an operator, recognizing that economic values hold greater significance from each company's perspective and that defined holds true for this research. Economic analyses often involve assessing the financial viability and benefits of projects, and these assessments can vary based on the specific goals, strategies, and circumstances of each operator or company.

Chapter 5: Conclusions and Recommendation

The conclusions derived from this study as well as the proposed recommendations for future studies to improve upon this work are presented in this chapter.

5.1 Summary and Conclusions

In this study, a reservoir simulation framework has been proposed for the development of a green marginal field. Some of the key parameters for describing the Ratson field including pressure, and PVT data were not readily available. These parameters importantly form the basis for defining other reservoir properties through laboratory analyses or empirical correlations that guide intending recovery and reservoir simulation.

To mitigate the problem of data paucity in this study, the reservoir properties, geological data, and PVT analyses were obtained from analog fields. This approach was necessary to create a database of properties required to use a reservoir simulation to derive the recovery factors. The recovery factors can then be used to validate the reserves from decline curve analyses. The proposed methodology of well design and production performance sensitive analyses provides a framework for optimizing the production strategy for recovery of hydrocarbons from Sand C in the Ratson field located in the Niger Delta. By incorporating input parameters along with appropriate assumptions and constraints, results were obtained which suggest that fields like the Ratson Sand C can be developed using the reservoir framework developed in this study. Additionally, the following conclusions can be drawn from the methodology and results derived from this study:

1 The reservoir properties, fluid contact, and gross rock volumes derived from the static model were used to estimate the volumes of fluids in place (STOIIP) in Sand C of the Ratson field to be 23.2 MMstb.

2. Black oil simulator was used to initialize a comprehensive model of the Sand C of the Ratson field to get an estimated STOIIP of 27.2 MMstb. This indicates a percentage difference of 17% compared to the static volume.
3. Well modelling performed with a well simulator for the producer yielded an optimal oil production rate of 1020 STB/D at tubing size of 2 inches, and a tubing head pressure (THP) of 500 PSIA.
4. Analyses conducted in the study to evaluate the impact of varying injection rates and THPs on the overall production performance of the Ratson field proved that the injection of gas at specific rate of 250 MSCF of gas yielded more oil and sustained longer production before reaching the terminal water-cut.
5. An integrated approach of identifying risks and uncertainties associated with subsurface and surface development is formulated in this study. This approach has subsurface roots which are ranked in a matrix to assess their defined impact on project management.

5.2 Recommendations

The following recommendations are suggested to highlight areas of additional research to improve the validity of the work.

1. Core sampling can be conducted to validate PVT and SCAL input properties.
2. There is a need for the continuous updating of the reservoir model with new data and results as more reservoir characterization is discovered or authenticated.
3. Further research can be conducted on the utilization of recovered gas volumes other than injection into the reservoir considered in this study. Stochastic programming models and analysis can be explored to study gas utilization in the Ratson field.

Nomenclature

q_0 - initial flow rate

a - instantaneous decline factor

A = area

AOF – Absolute Open Flow

API – American Petroleum Institute

BBL/D – Barrels per Day

Bg = Gas Formation Volume Factor

Bo = Oil Formation Volume Factor

Boi – Formation Volume Factor

BSCF – Billion Standard Cubic Feet

CAPEX – Capital Expenditure

E - Recovery efficiency.

FBHP – Flowing Bottomhole Pressure

FDP – Field Development Plan

FOPR – Field Cumulative Oil Production Rate

FOPT – Field Cumulative Oil Production Total

FVF – Formation Volume fcator

GIIP – Gas Initially in Place

GOC – Gas Oil Contact

GOR – Gas Oil Ratio

GRV – Gross Rock Volume

H - net pay, ft

ICS - International Commission on Stratigraphy

IPR – Inflow Performance Relationship

IRR – Internal Rate of Return

lb/ft^3 – pounds/feet cube

mD – milliDarcy

MMSCF/D – Million Million Standard Cubic Feet/ Day

MMSTB – Million Million Stock Tank Barrels

MSCF/STB – Million Standard Cubic Feet/ Stock Tank Barres

NPV – Net Present Value

NTG = net to gross ratio

^{o}API - Degree API

^{o}F - Fahrenheit

OIIP – Oil Initially in Place

OPEX – Operating Expenditure

PHI – Porosity

PI – Profitability Index

PSI/FT – Pounds Square Inch/Feet

PVDG – dry gas PVT properties

PVT – Pressure Volume Temperature

PVTO – Live oil PVT properties

PVTW – Water PVT properties

QC- Quality Control

S.T.P – Standard Temperature and Pressure

SCAL – Special Core Analysis

SCF/STB – Standard Cubic Feet/ Stock Tank Barrels

Shc – Hydrocarbon Saturation

SIS – Sequential Indicator Simulation

So - Oil saturation

STB/D – Stock tank Barrels/Day

STB/D/psi - Stock tank Barrels/Day/Pounds Square Inch

STB/YR – Stock Tank Barrels/Year

STOIIP – Stock Tank Oil Original In Place

Sw – Water saturation

t – time

THP – Tubing Head Pressure

Vb = gross rock volume (GRV)

VFP – Vertical Flow Performance

VLP – Vertical Lift Performance

WBP – Well Bottom Hole Pressure

WOC – Water Oil Contact

WWCT – Well Water Cut

φ = porosity

q - low rate at time, *t*

References

Adepoju, A., Adekola, S. A., Omotoye, S., & Akinlua, A. (2018). Light Hydrocarbon Geochemistry of Crude Oils from Eastern Niger Delta. *Petroleum Science and Technology*.

Aigbedion, I. (2007). A Case Study of Permeability Modeling and Reservoir Performance in the Absence of Core Data in the Niger Delta, Nigeria. *Journal of Applied Sciences*, 772-776.

Al-Marhoun, M. (1992). New Correlations for Formation Volume Factors of Oil and Gas Mixtures. *J Can Pet TEchnol*.

Alonge, O. T. (2021). *Comparative Analysis of limited and Fully Compositional Simulation of a Niger Delta Gas-Condensate*. Abuja: Africann University of Science and Technology.

Amihere-Ackah, P. (2020). A Field Development Plan for Catshill Brown Oilfield in Trinidad Utilizing Waterflood Simulation. *East Africa Scholars Journal of Engineering and Computer Sciences*.

Ashiedu, R. I., & Olarewaju-Alo, B. O. (1998). Utilisation of "Waste" Gas and Water Streams: An Example of Environmental Impact Reduction Effort during Field Development Planning in the Niger Delta. *SPE International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production.* Society of Petroleum Engineers (SPE).

Atsegwasi, G. (2020, October 22). OIL AND GAS OPERATIONS IN NIGERIA: THE NEED FOR WELL HEAD SAFETY. *Asia Pacific Law Review*, p. 3.

Azeezat, K. (2020, August 7). *HISTORY OF THE NIGERIAN PETROLEUM INDUSTRY*. Retrieved from https://www.linkedin.com/pulse/history-nigerian-petroleum-industry-kazeem-azeezat

Beggs, H., & Robinson, J. (1975). Estimating the Viscosity of Crude Oil Systems. *J Pet Technol*, 1140-1141.

Behrenbruch, P. (1993). Offshore oilfield Development Planning. *Journal of Petroleum Technology*, 1.

Breitenbach, E. (1991). Reservoir Simulation: State of the Art. *Journal of Petroleum Engineering Technology*, 1033-1036.

Carpenter, C. (2022). Probabilistic Approach Guides Field Development Plan in Niger Delta. *Journal of Petroleum Technology*, 69-71.

Coates, G. R., & Dumanoir, J. (1973). A New Approach To Improved Log-Derived Permeability. *SPWLA Fourteenth annual Logging Symposium.* Lafayette, Louiisiana.

Cohen, K. M., Harper, D., & Gibbard, P. (2023, March 19). *International Chronostratigraphic Chart*. Retrieved from International Commission on Stratigraphy, IUGS: www.stratigraphy.org

Dim, C. I. (2016). *Hydrocarbon Prospectivity in the Eastern Coastal Swamp Depo-belt of the Niger Delta Basin.* Springer Cham.

Doust, H. (1989). The Niger Delta: Hydrocarbon Potential of a Major Tertiary Delta Province. *KNGMG Symposium 'Coastal Lowlands, Geology and Geotechnology* (pp. 203-212). Dordrecht: Kluwer Academic Publishers.

Ejeke, C. F. (2022). *Static Modeling of a Marginal Field to Support Dynamic Simulation.* Flowgrids Ltd Internal Report.

Ejeke, C. F. (2022). *Static Modeling of a Marginal Field to Support Dynamic Simulation.* Flowgrids Ltd Internal Report.

Eke, P. O., & Okeke, F. N. (2016). Identification of hydrocrabon Regions in Southern Niger Delta Basin of Nigeria from Potential Field Data. *International Journal of Scientific & Technology Research* , 96-99.

Emujakporue, G. O. (2016). Assessment of Hydrocarbon Potential in Owem Field in Niger Delta, Nigeria. *International Journal of Geosciences* , 335-344.

Evamy, B. D., Haremboure, J., & Kamer. (1978). Hydrocarbon Habitat of Tertiary Niger Delta. *The American Association of Petroleum Geologists Bulletin*.

Ezebialu, K., Ubituogwale, M., Odegua, E., & Idehen, A. (2020). Field Development Planning based on Static, Dynamic and Geomechanical Modelling of X Field. *Nigeria Annual International Conference and Exhibition* (p. 3). Society of Petroleum Engineers.

Ezebialu, K., Ubituogwale, M., Odegua, E., & Idehen, A. (2020). Field Development Planning based on Static, Dynamic and geomechanical Modelling of X Field, Niger Delta, Nigeria. *SPE Nigeria Annual International Conference and Exhibition.* Society of Petroleum Engineers (SPE).

Glaso, O. (1980). Generalized Pressure-Volume-Temperature Correlations. *J Pet Technol*, 785-795.

Hooper, R. J., Fitsimmons, R. J., & Vendeville, B. C. (2002). The Role of Deformation in Controlling Depositional Patterns in the South-central Niger Delta, West Africa. *Journal of Structural Gelogy*, 856.

Magoon, L. B., & Dow, W. G. (1994). The Petroleum System - From Source to Trap. *AAPG Memoir*, 3-24.

Obiadi, I. I., Ozumba, B. M., & Osterloff, P. (2012). Regional Sequence Startigraphic Framework and Structural Evolution of Parts of the Eastern Swamp Depobelt of the Niger Delta, Nigeria. *NAPE Bulletine*, 95-103.

Olayiwola, A. M., & Bamford, K. M. (2019). Depositional Environment and Reservoir Charaterization of the Deep Offshore Upper Miocene to Early Pilocene Agbada Formation, Niger Delta, Nigeria. *Journal of African Earth Sciences*, 17.

Oluwajana, O. A., Ehinola, O. A., Okeugo, C. G., & Adegoke, O. (2017). Modeling Hydrocarbon Generation Potentials of Eocene Source Rocks in the Agbada Formation, Northern Delta Depobelt, Niger Delta Basin, Nigeria. *J Petrol Explor Technol*, 379-388.

Organization of the Petroleum Exporting Countries. (2022). *Nigeria Facts and Figures*. Retrieved from Organization of the Petroleum Exporting Countries: https://www.opec.org/opec_web/en/about_us/167.htm

Osinowo, O. O., Ayorinde, J. O., Nwankwo, C. P., Ekeng, O. M., & Taiwo, O. B. (2018). Reservoir Description and Characterization of Eni Field Offshore Niger Delta, Southern Nigeria. *J Petrol Explor Prod Technol*, 381-397.

Petrosky, G. E., & Farshad, F. (1998). Pressure-Volume_Temperature Correlations for Gulf of mexico Crude Oils. *SPE Res Eval & Eng* , 416-420.

Reijers, T. (2011). Stratigraphy and Sedimentology of the Niger Delta. *Geologos*, 133-162.

Reijers, T. P. (1996). The Niger Delta Basin. In *Geology, Sedimentary Geology and Stratigraphy in Nigeria* (pp. 103-117). SPDC.

Reijers, T. P. (n.d.). The Niger Delta Basin.

ResInsight. (2023). *ResInsight*. Retrieved from https://resinsight.org/about/

Short, K. C., & Stauble, A. J. (1967). Outline of Geology of the Niger Delta. *The American Association of Petroleum Geologists*, 761-779.

SLB. (2023, April 10). *ECLIPSE Industry-Reference Reservoir Simulator*. Retrieved from PRODUCT SOLUTIONS: https://www.software.slb.com/products/eclipse#Unrivaled%20Depth%20and%20Breadth%20of%20Functionality

Sorgard, Eirik, Oko, Anne, E., Baird, Isaac, J., . . . Fresquez, S. M. (2023). Vito Project: Vito Field Development. Houston, Texas, USA: Offshore Technology Conference.

Standing, M. B. (1957). A Pressure-Vlume-Temperature Correlation for Mixtures of California Oils and Gases. In A. P. Institute, *Drilling and Production Practice* (pp. 275-287). American Petroleum Institute.

Steyn, P. (2009, April 20th). *Oil Exploration in Colonial Nigeria, C. 1903 - 1958.* Retrieved from CORE: https://core.ac.uk/display/9049842?utm_source=pdf&utm_medium=banner&utm_campaign=pdf-decoration-v1

Tuttle, M. L., Charpentier, R. R., & Brownfield, M. E. (1999). *The Niger Delta Petroleum System: Niger Delta Province, Nigeria, Cameroon and Equatorial Guinea.* Denver, Colorado: U.S. Department of the Interior.

Udosen, C., & Etok, A.-I. S. (2009). Fifty Years of Oil Exploration in Nigeria: The Paradox of Plenty. *Global Journal of Social Sciences*.

Utomi, J.-M. (2023, June 05). *Dangote refinery, industrialisation and lessons for Africans*. Retrieved from https://guardian.ng/opinion/dangote-refinery-industrialisation-and-lessons-for-africans/

Vasquez, M., & Beggs, H. (1980). Correlations for Fluid Physical Property Prediction. *J Pet Technol*, 968-970.

Wikipedia. (2023, February 19). *International Commission on Startigraphy*. Retrieved from https://en.wikipedia.org/wiki/International_Commission_on_Stratigraphy#References

APPENDIX

Additional results from the performance of wells simulated in this thesis (PROD01 and PROD02) are presented in this Appendix. Plots presented in Appendix A are that of the Base case, and Appendix B and Appendix C contain the results of the THP and gas injection rate sensitivity analyses, respectively. Appendix D shows plot of the PVT properties, geological timeframe and development of the Niger Delta, and the International Chronostratigraphic Chart.

Appendix A: Additional Results of the Base Case Simulation

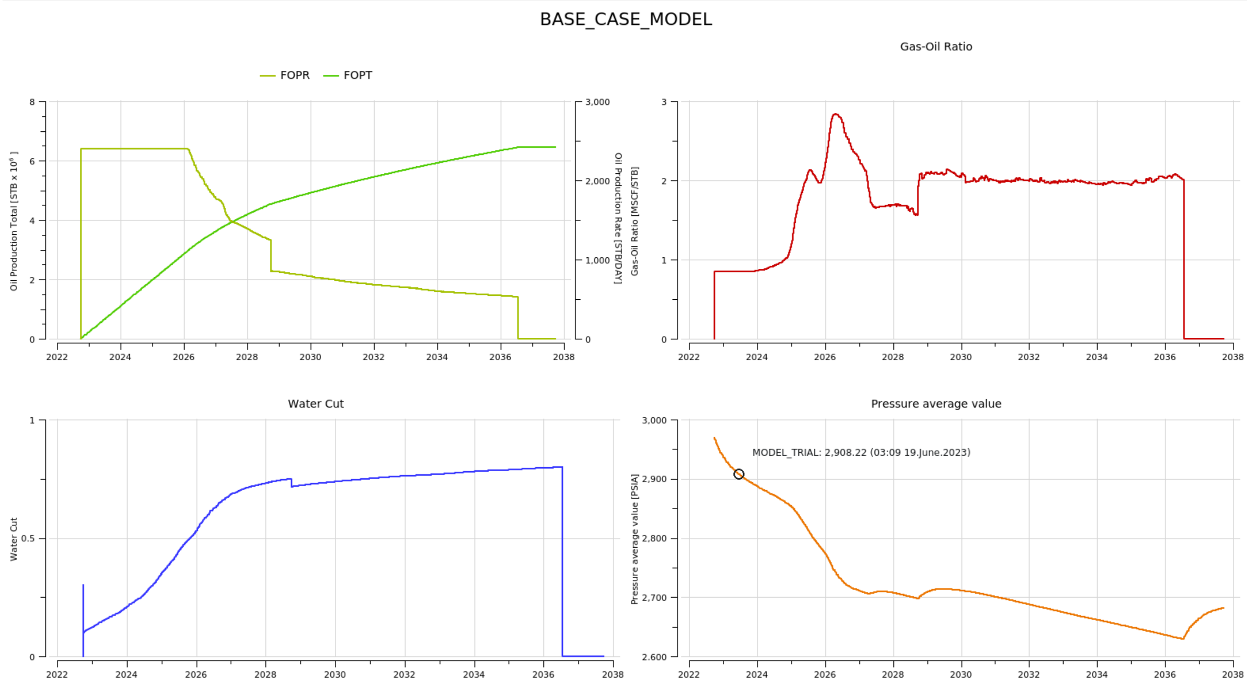

Figure A1: Field Performance of Model

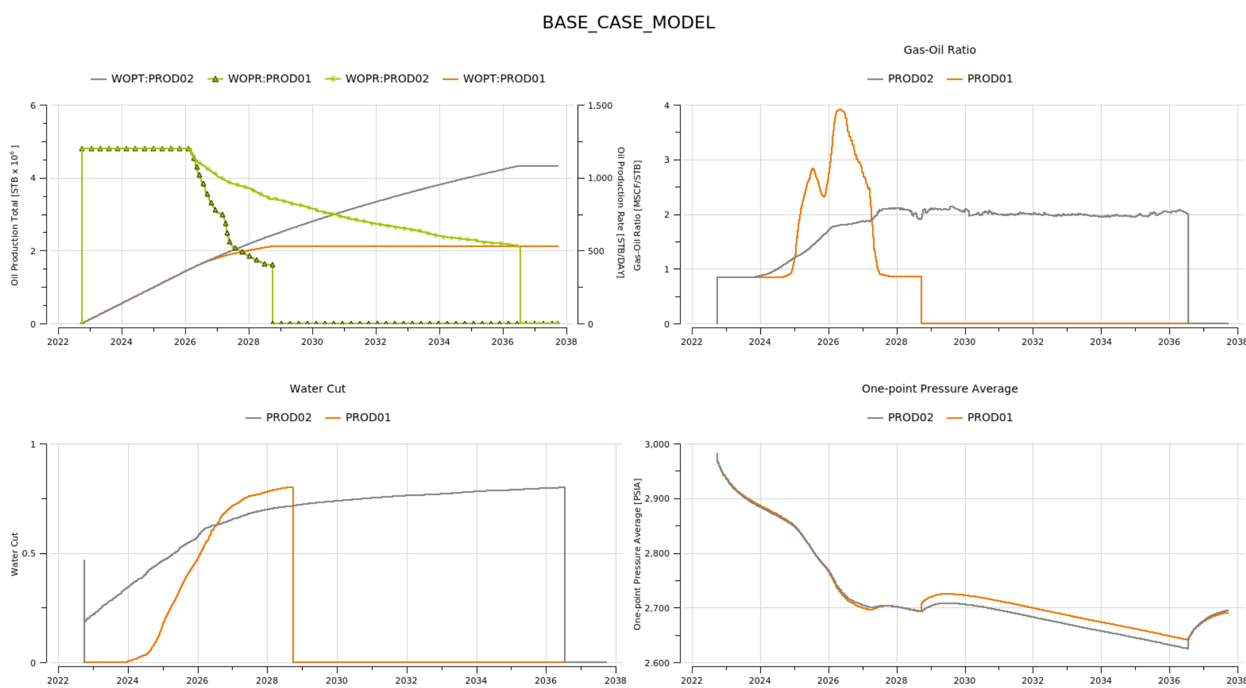

Figure A2: Wells Performance of Model

Appendix B: Results of THP Sensitivity Analysis

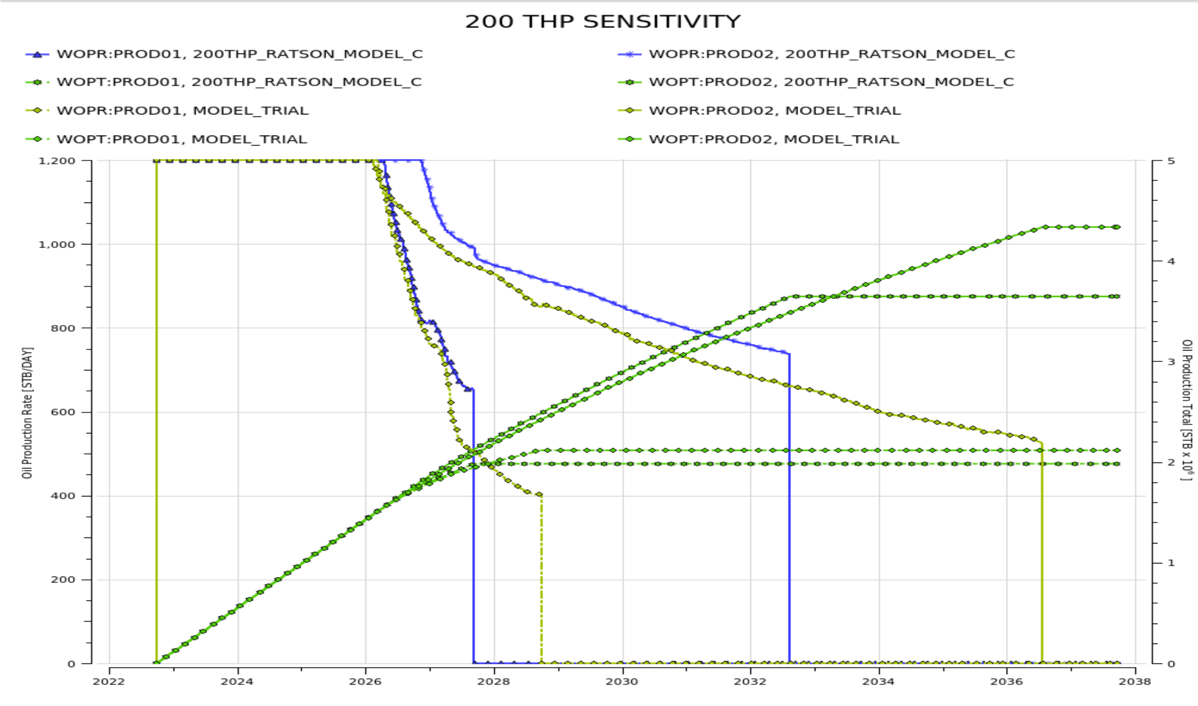

Figure B1: 200 THP FOPR/FOPT Sensitivity Plot

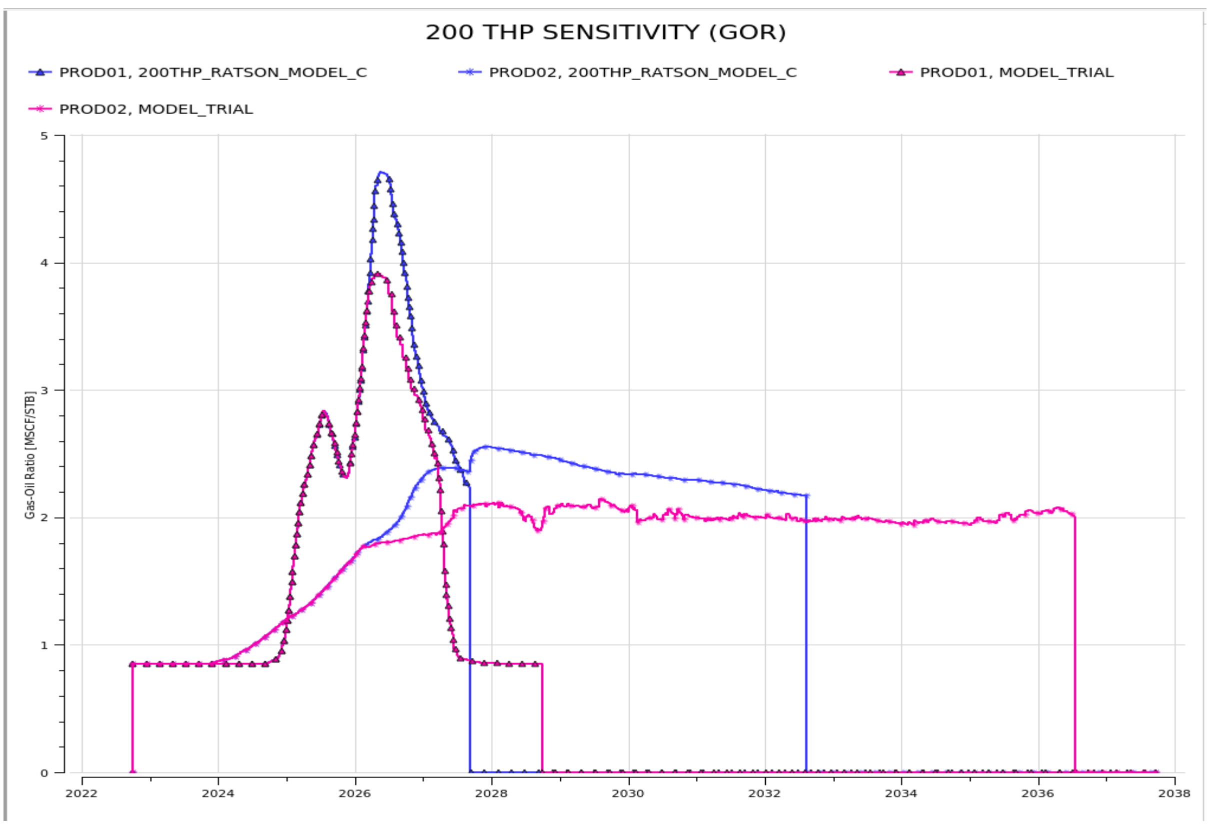

Figure B2: 200 THP GOR Sensitivity Plot

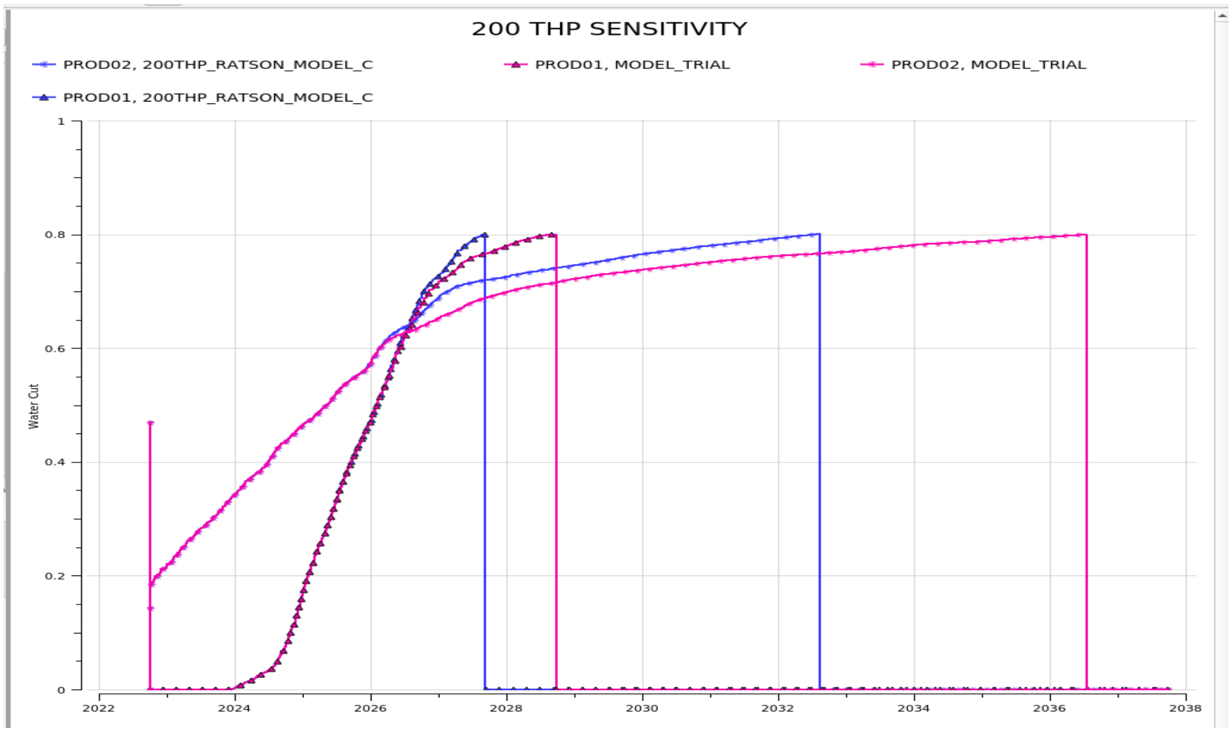

Figure B3: 200 THP WWCT Sensitivity Plot

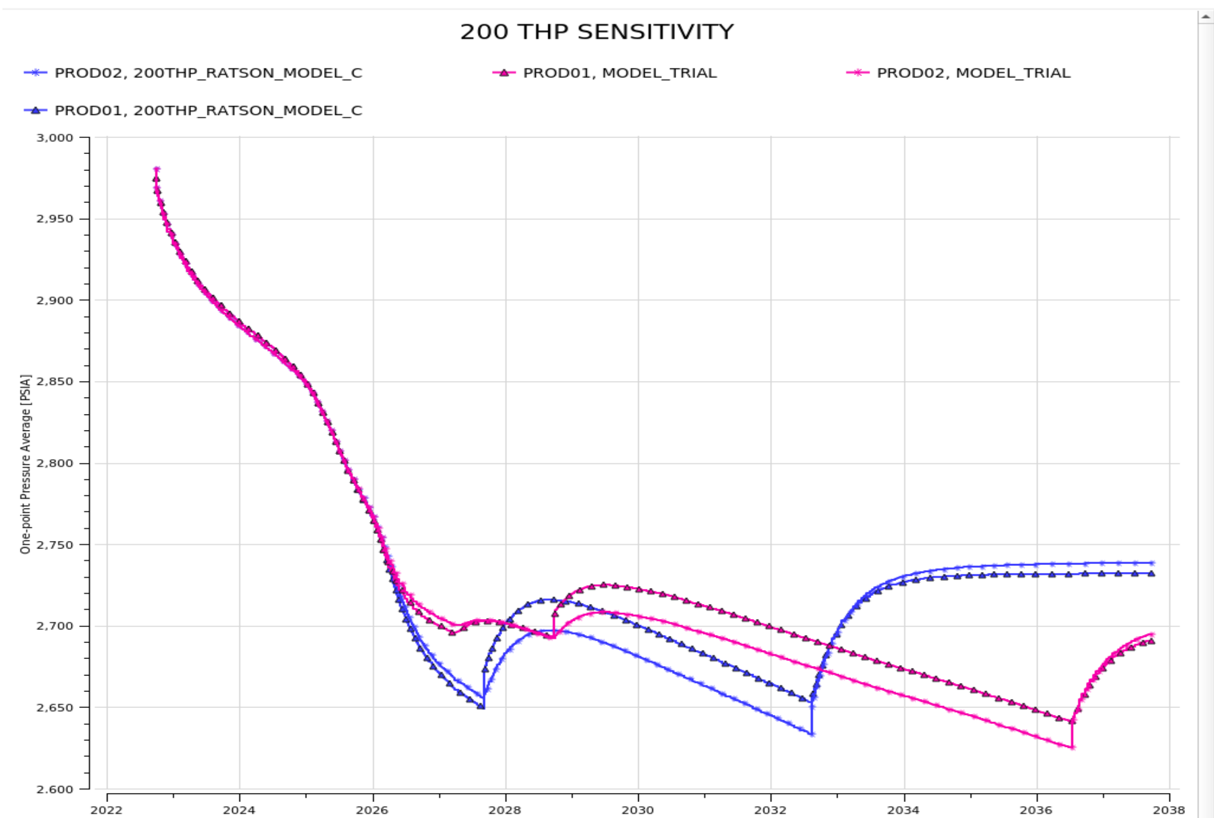

Figure B4: 200 THP WBP Sensitivity Plot

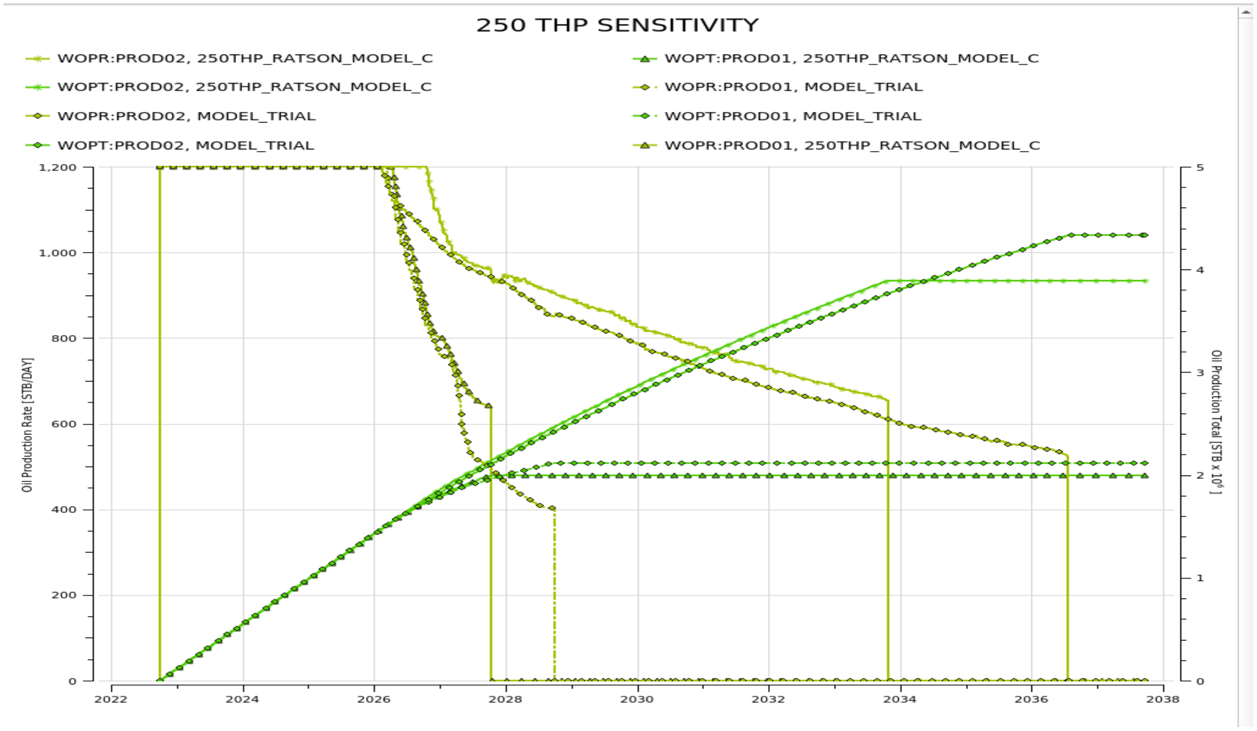

Figure B5: 250 THP FOPR/FOPT Sensitivity Plot

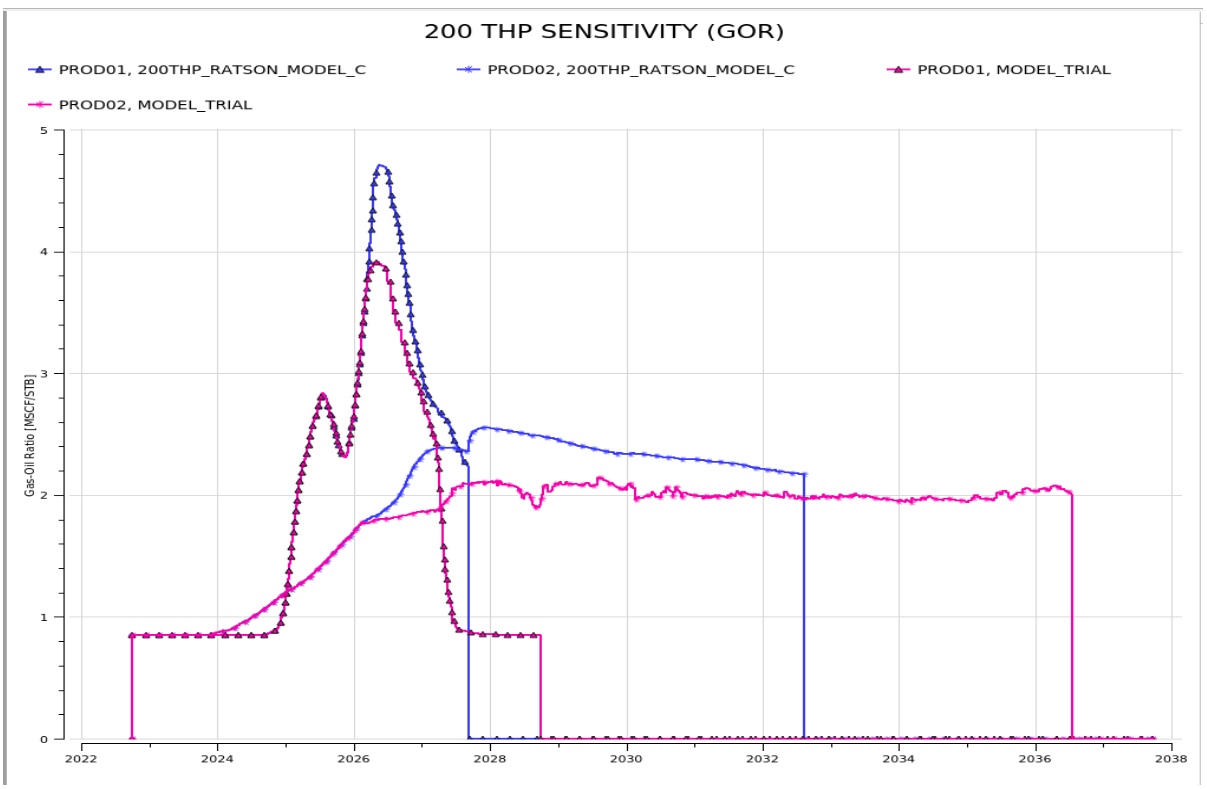

Figure B6: 250 THP GOR Sensitivity

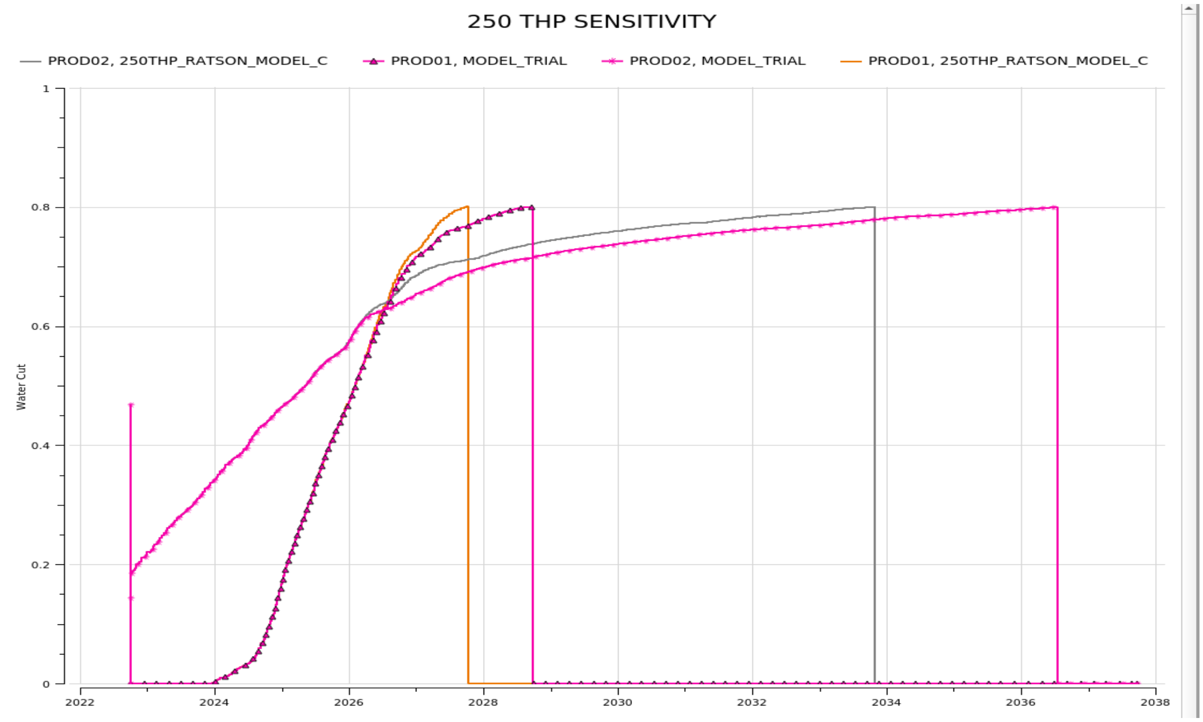

Figure B7: 250 THP WWCT Sensitivity Plot

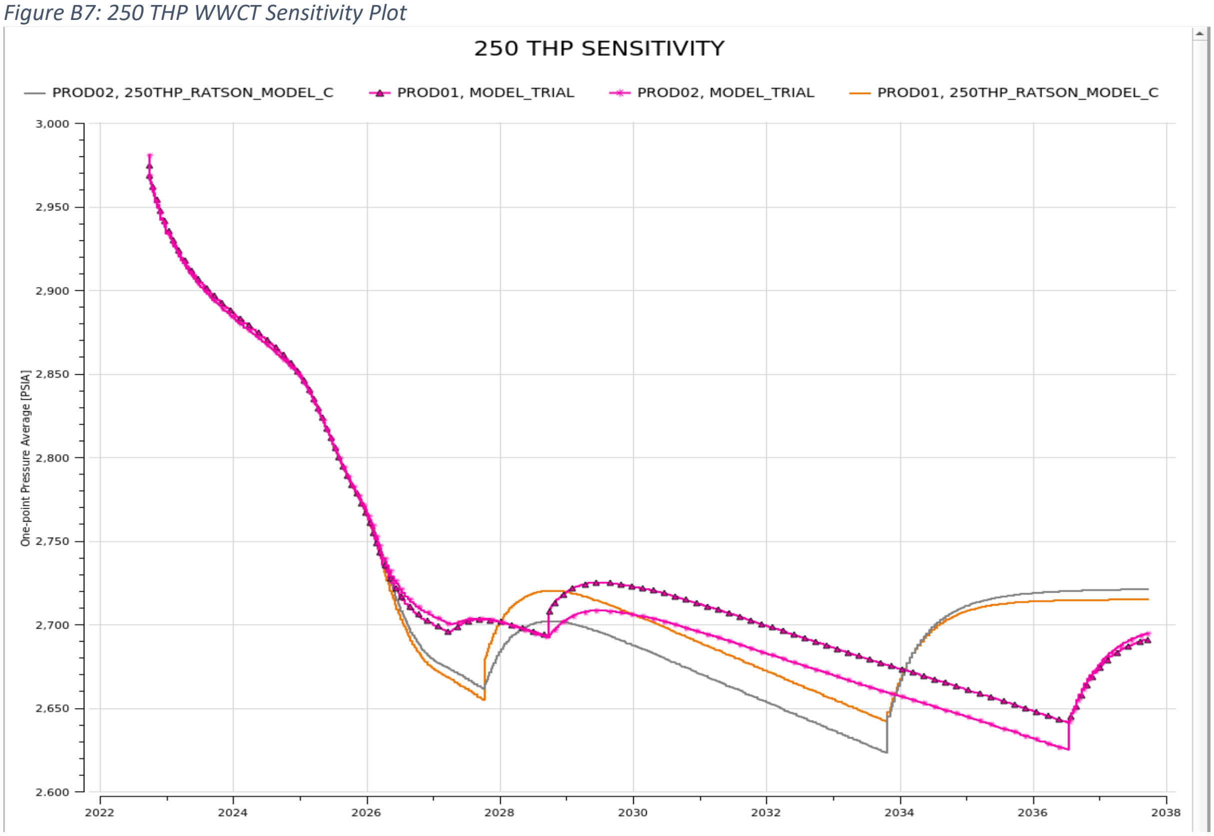

Figure B8: 250 THP WBP Sensitivity Plot

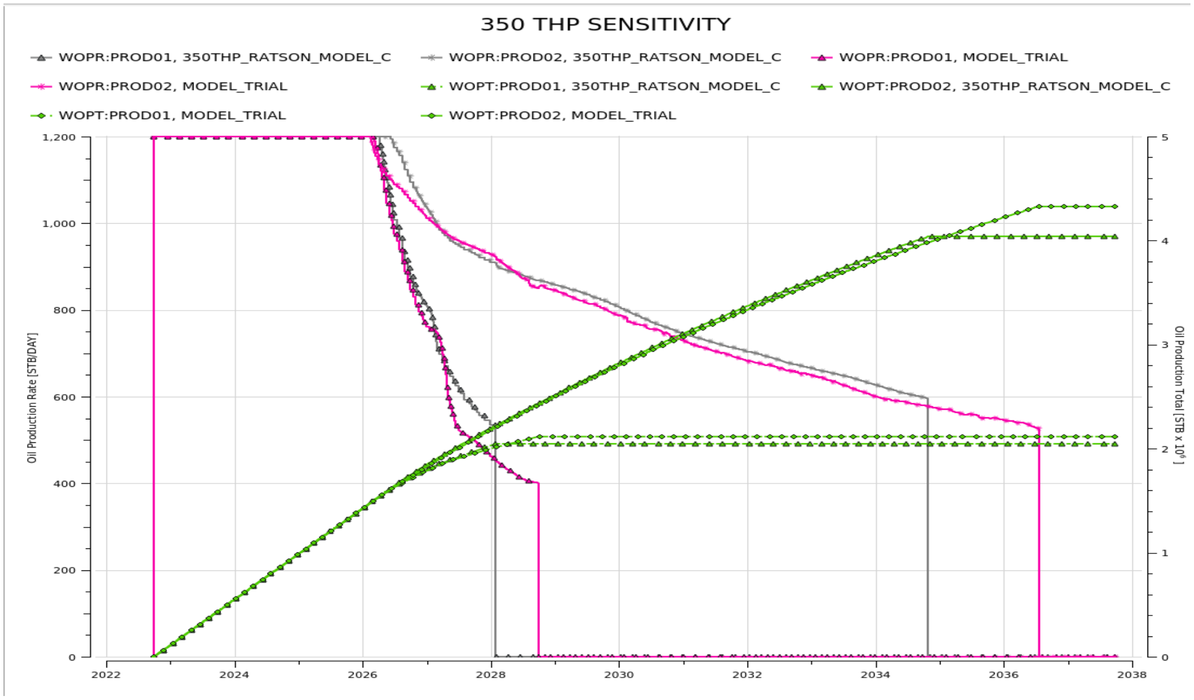

Figure B9: 350 THP FOPR/FOPT Sensitivity Plot

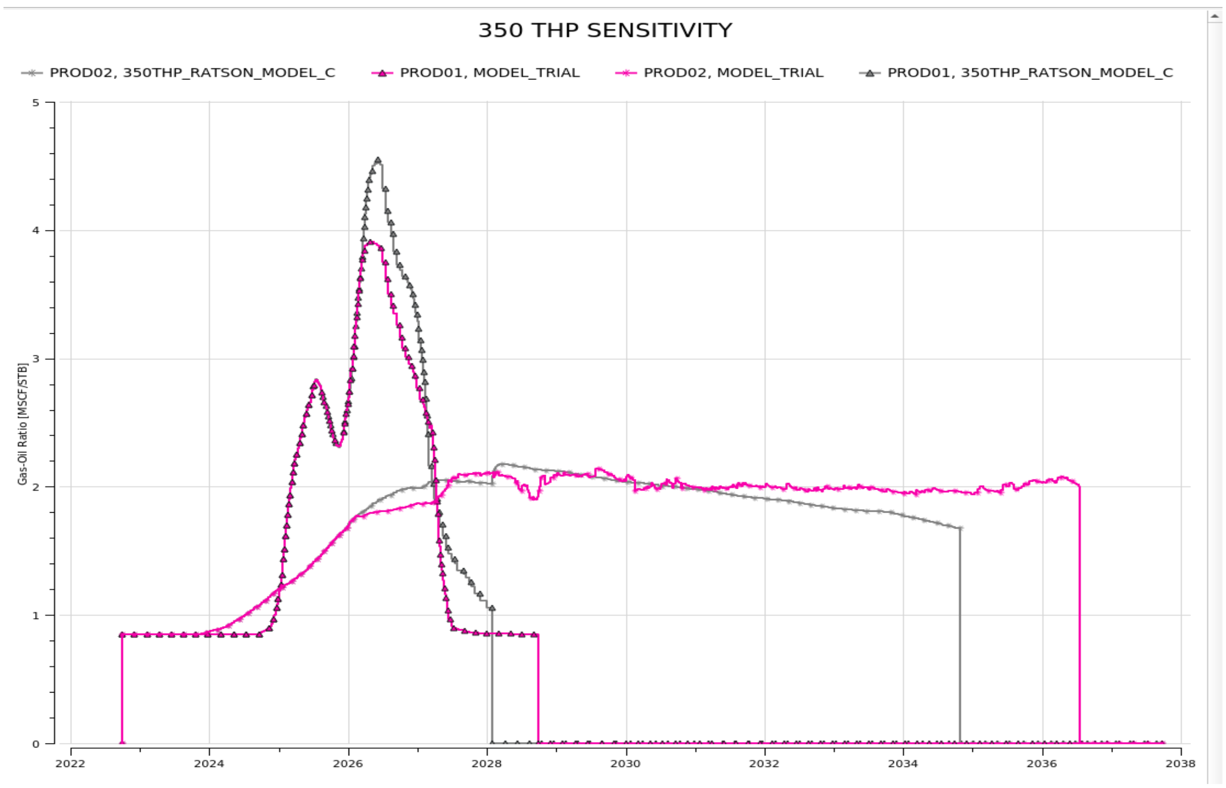

Figure B10: 350 THP GOR Sensitivity Plot

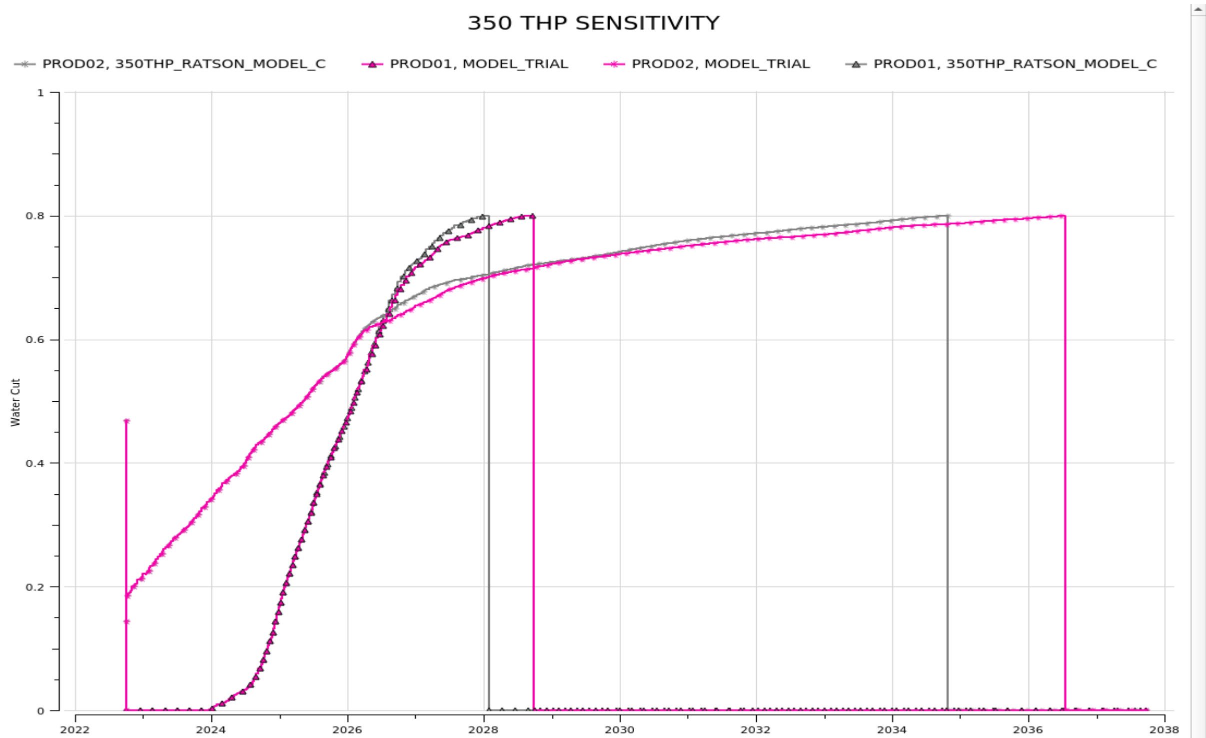

Figure B11: 350 THP WWCT Sensitivity Plot

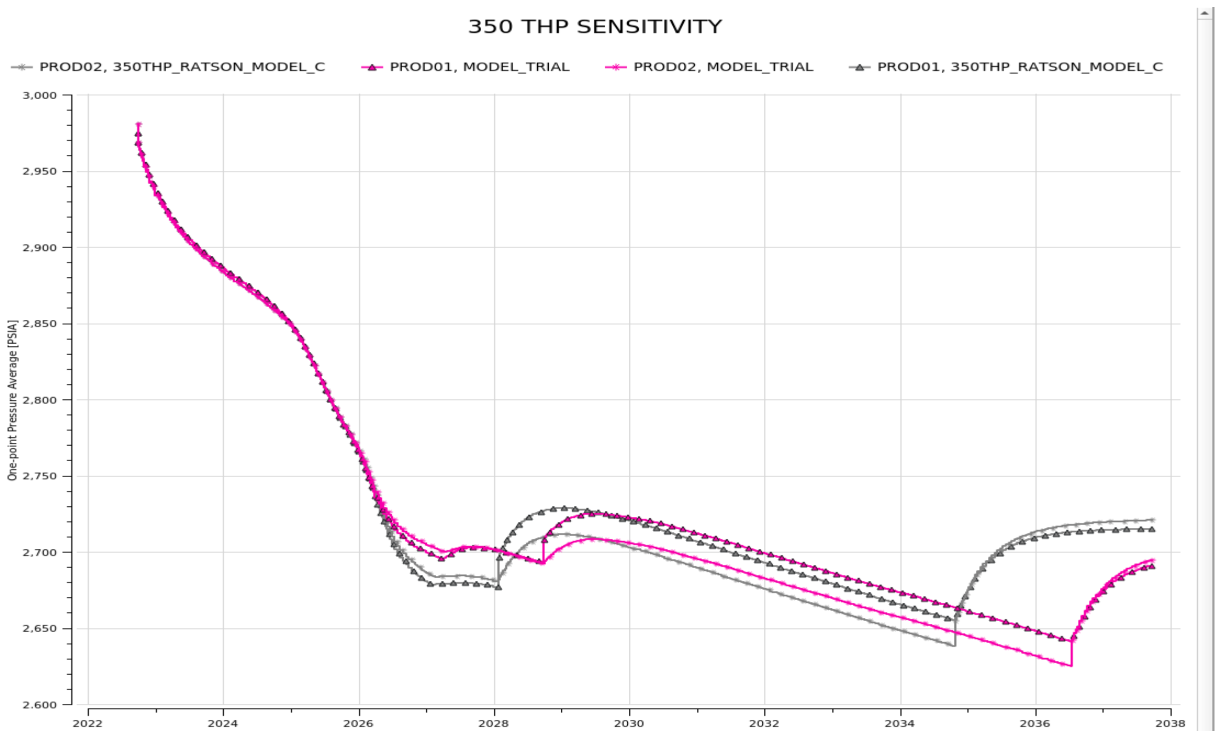

Figure B12: 350 THP WBP Sensitivity

Appendix C: Results of Gas Injection Rate Sensitivity Analysis

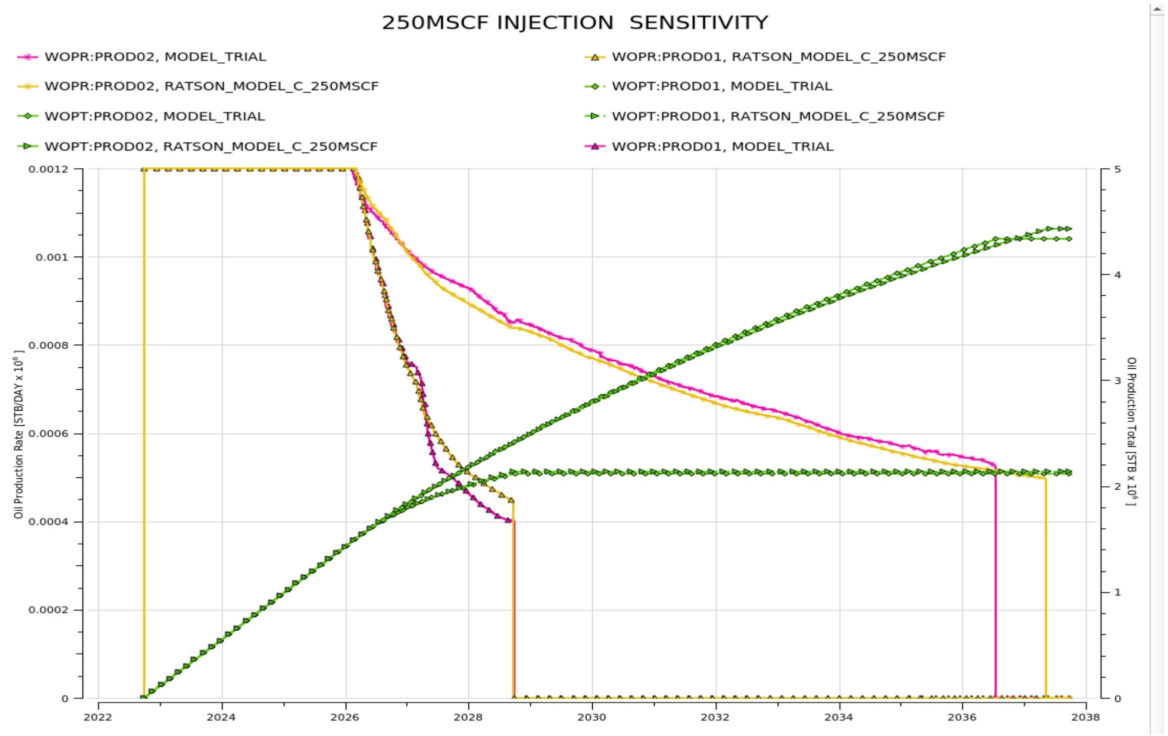

Figure C1: 200 MSCF FOPR/FOPT Sensitivity

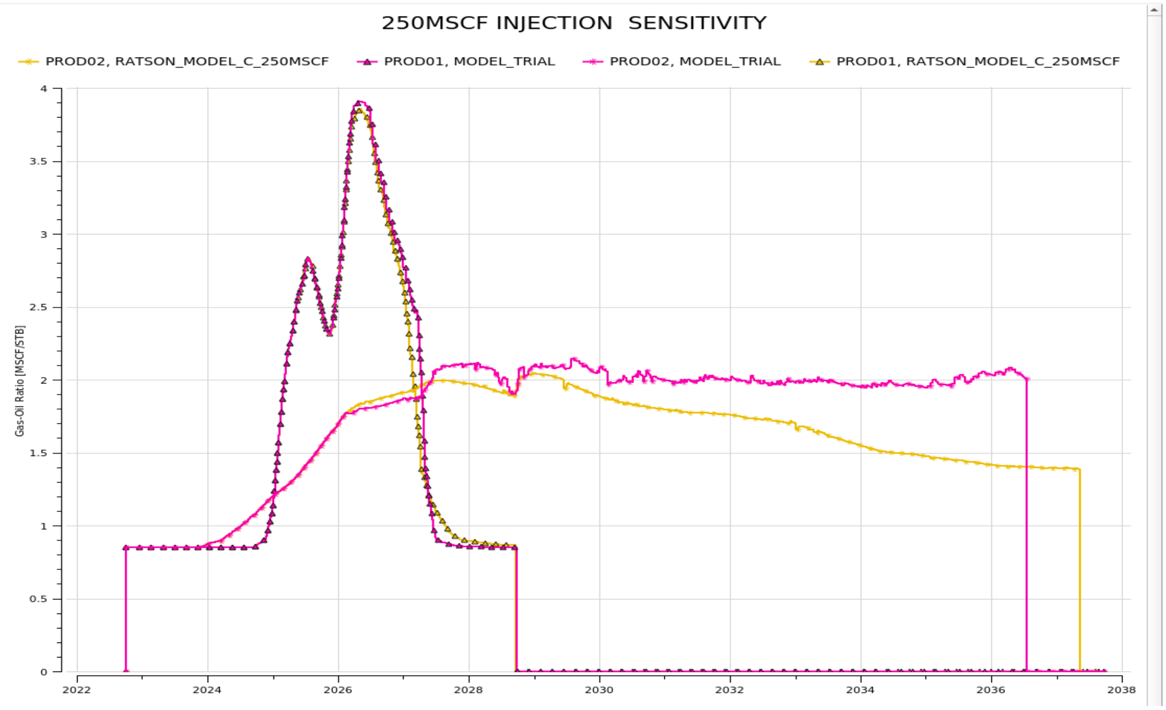

Figure C2: 250 MSCF GOR Sensitivity Plot

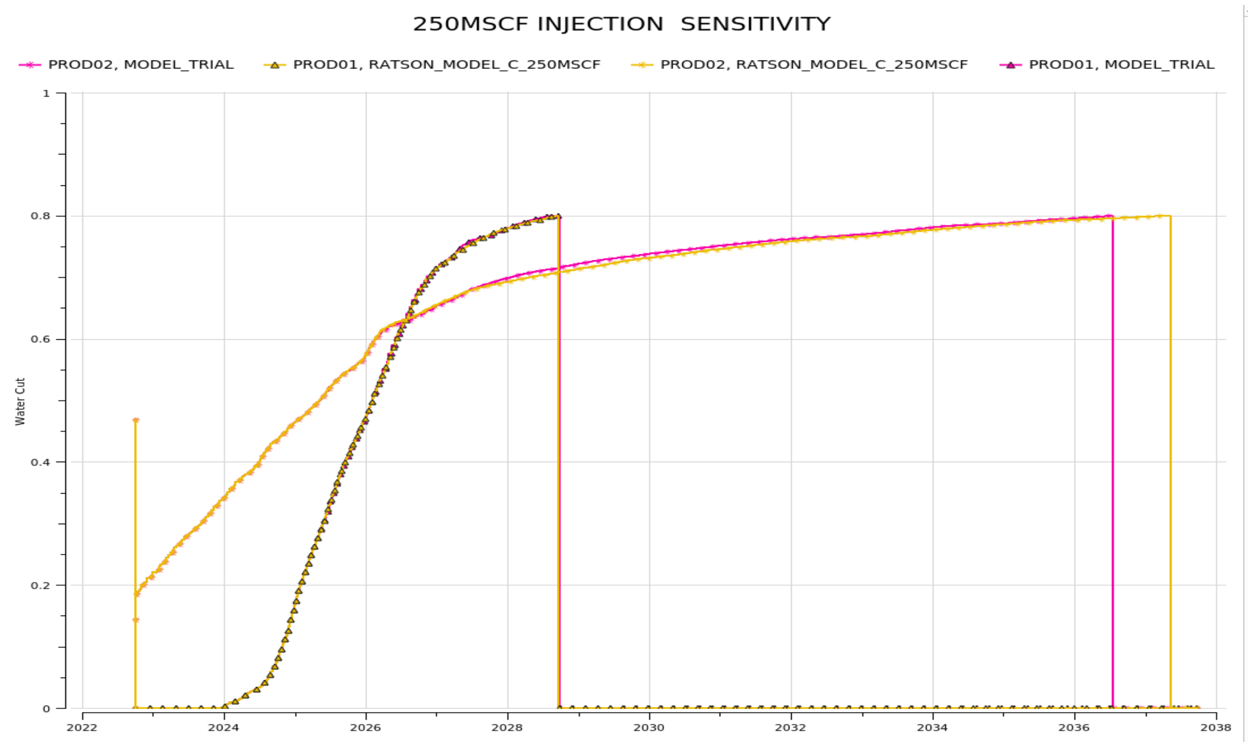

Figure C3: 250 MSCF WWCT Sensitivity Plot

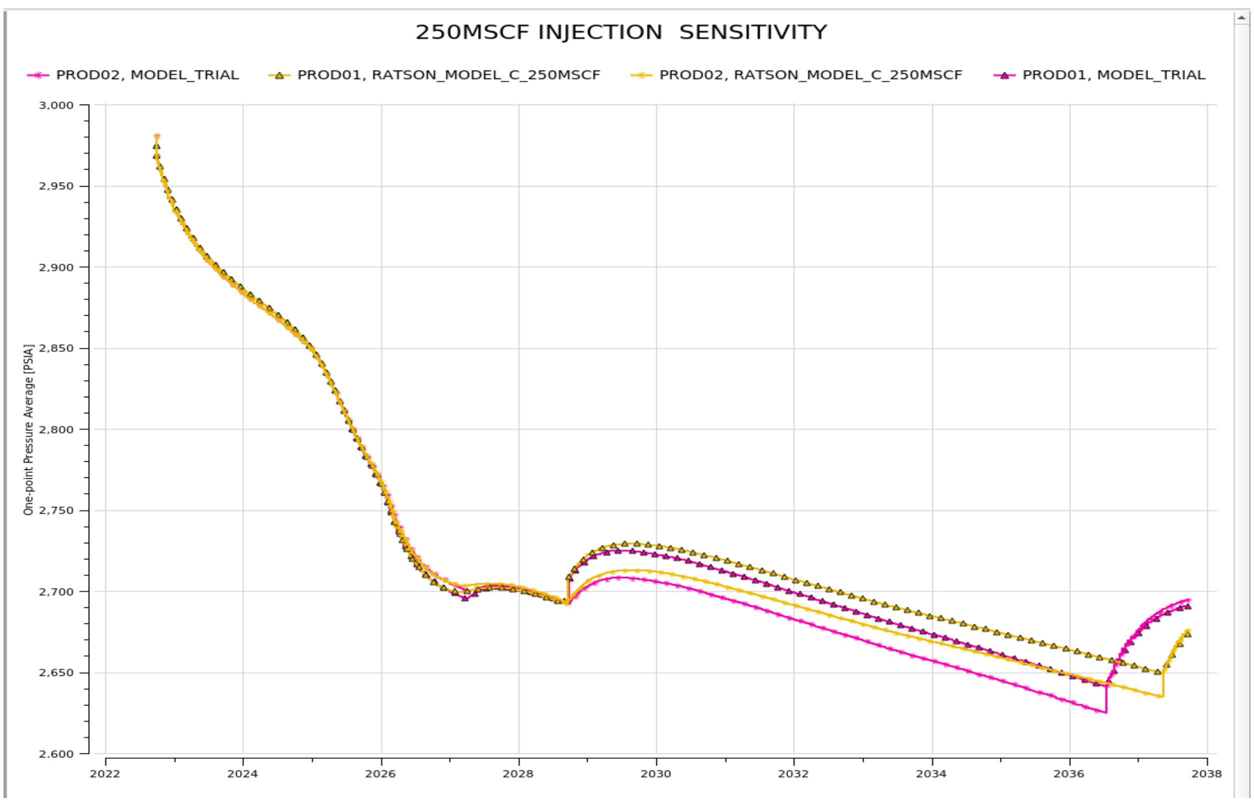

Figure C4: 250 MSCF WBP Sensitivity Plot

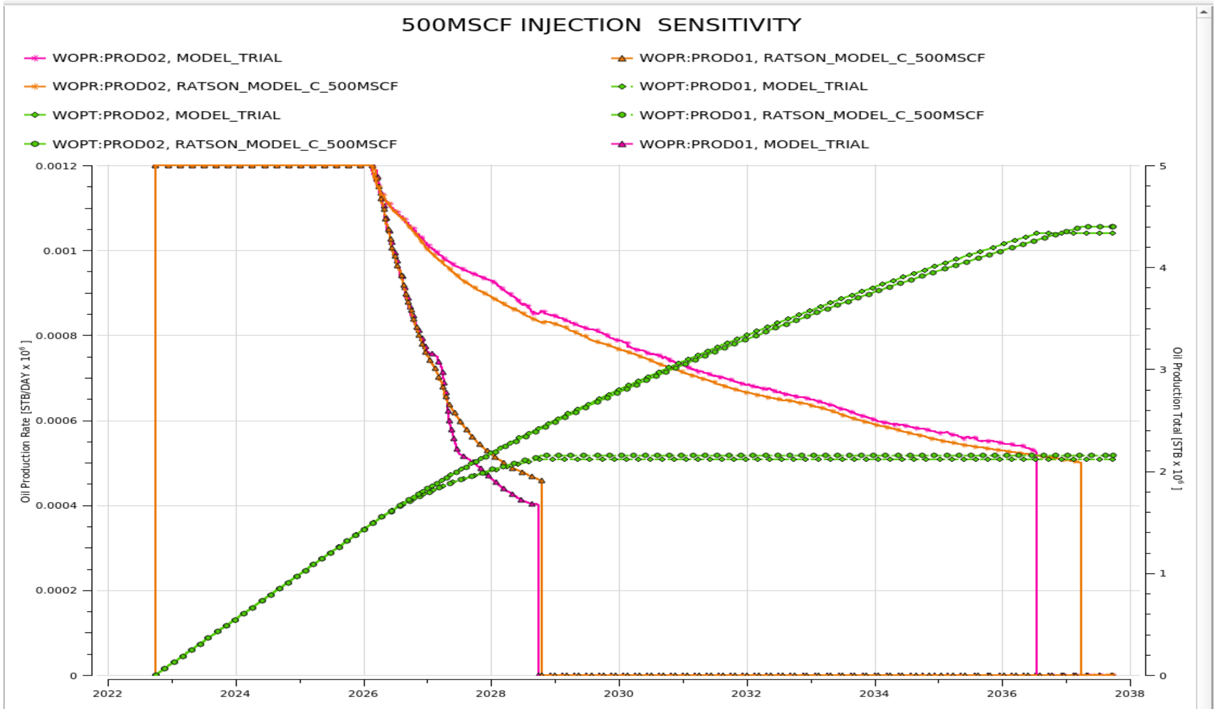

Figure C5: 500 MSCF FOPR/FOPT Sensitivity Plot

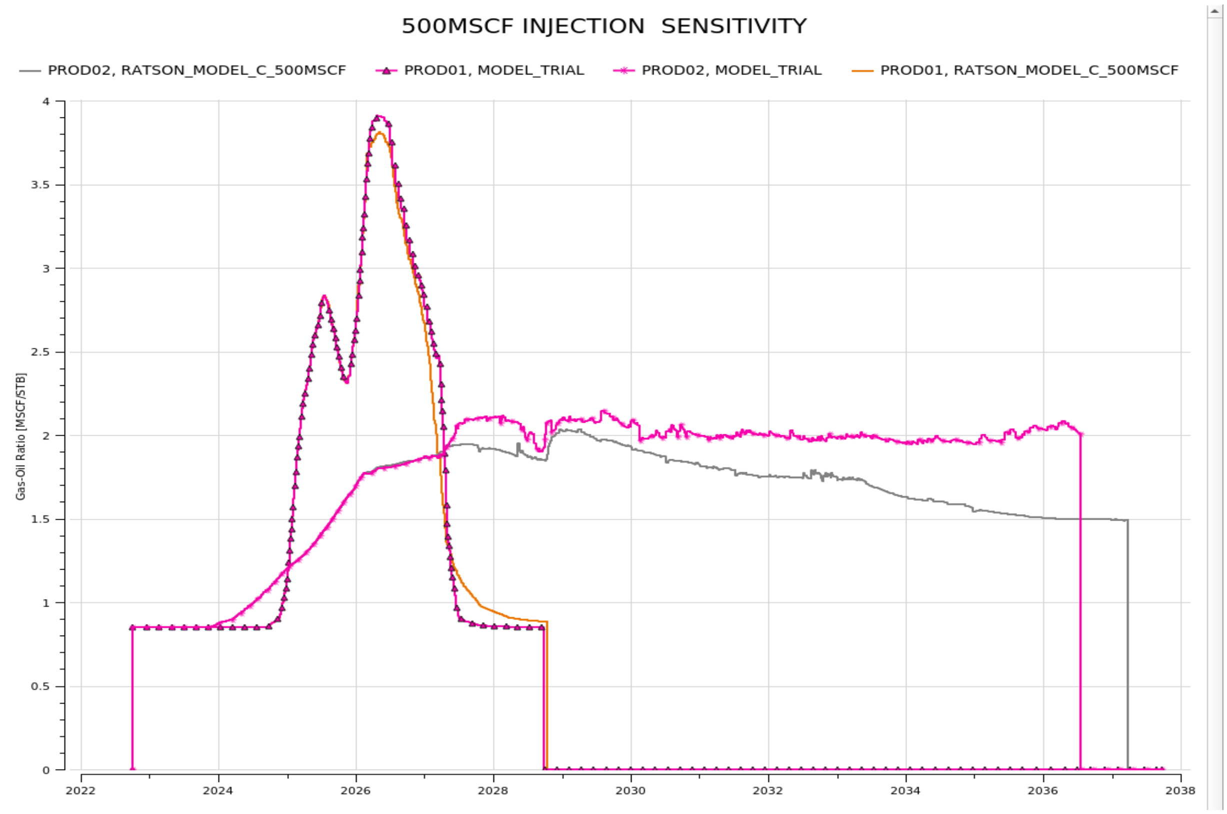

Figure C6: 500 MSCF GOR Sensitivity Plot

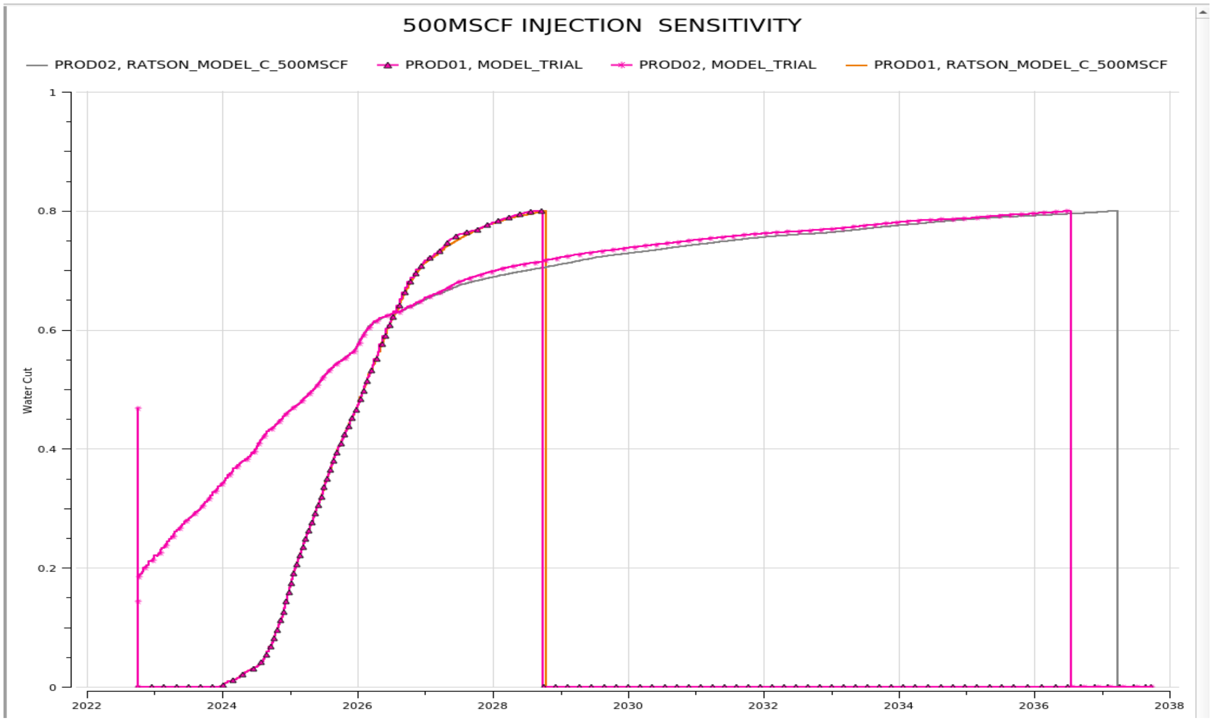

Figure C7: 500 MSCF WWCT Sensitivity Plot

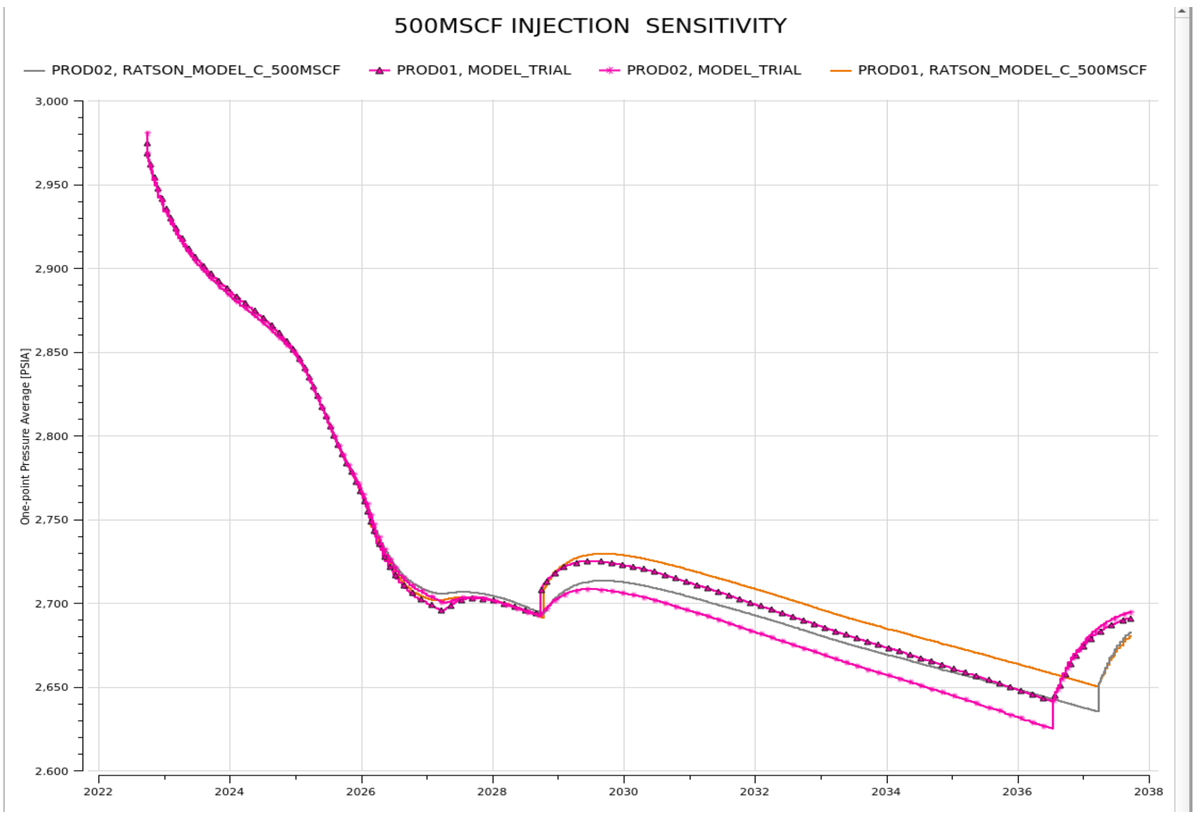

Figure C8: 500 MSCF WBP Sensitivity Plot

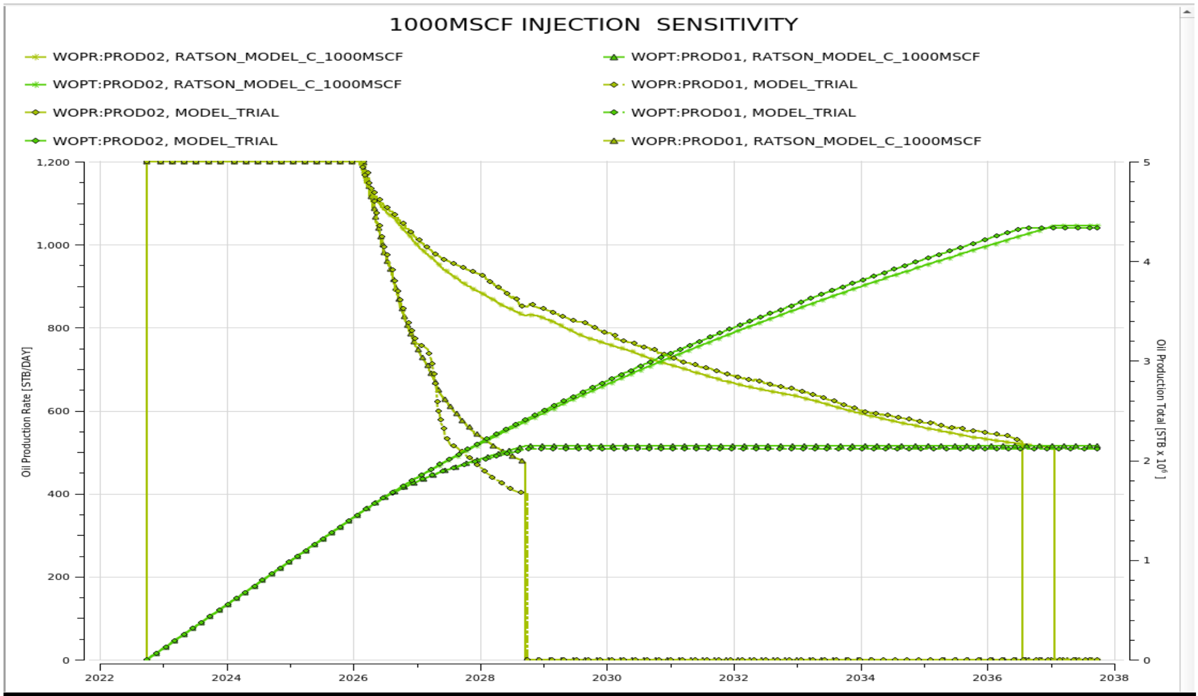

Figure C9: 1000 MSCF FOPR/FOPT Sensitivity Plot

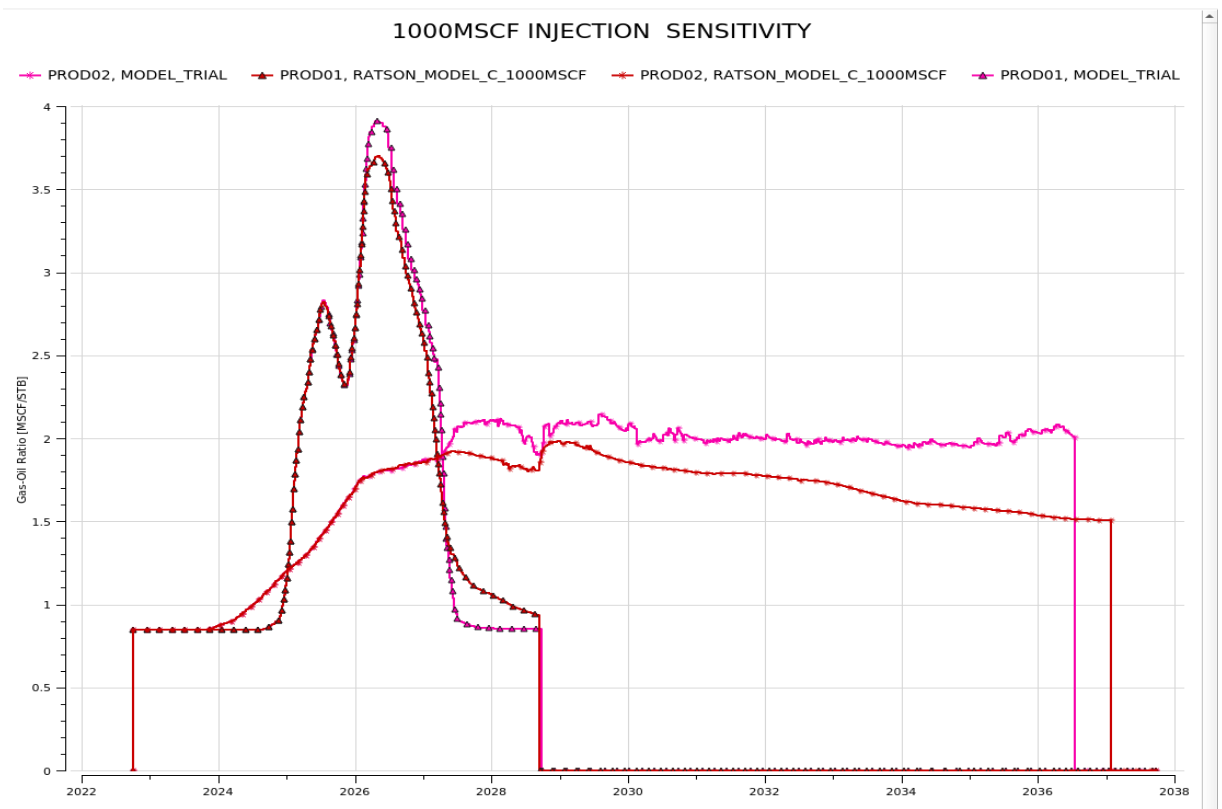

Figure C10: 1000 MSCF GOR Sensitivity Plot

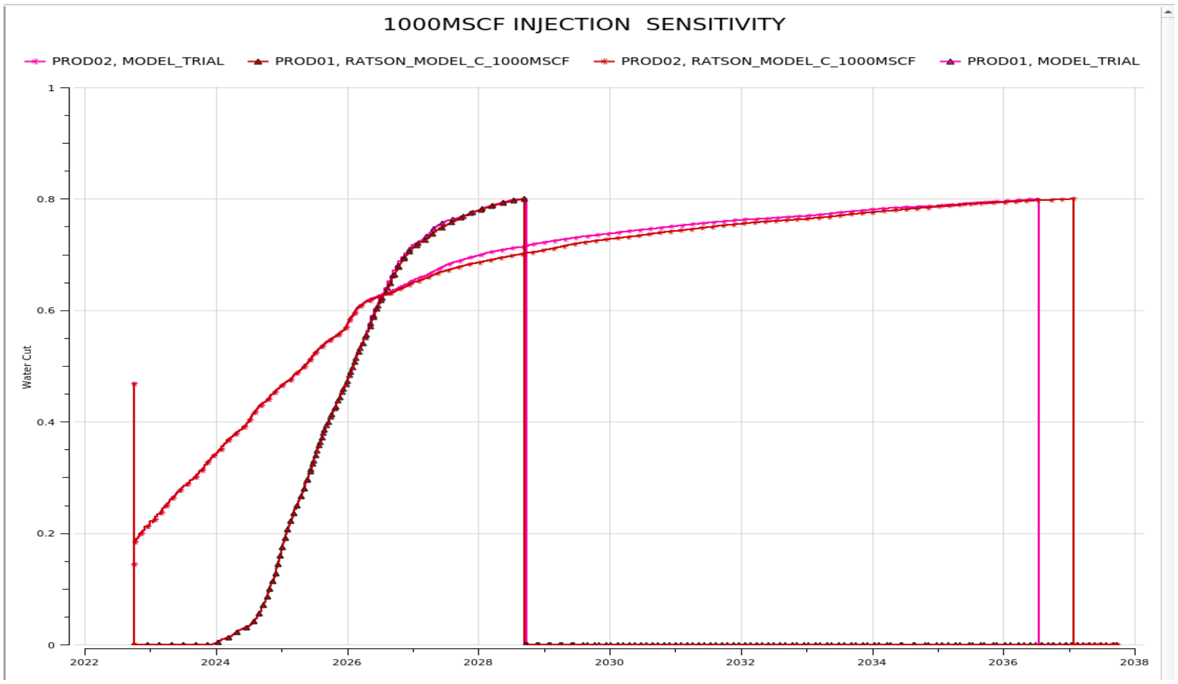

Figure C11: 1000 MSCF WWCT Sensitivity Plot

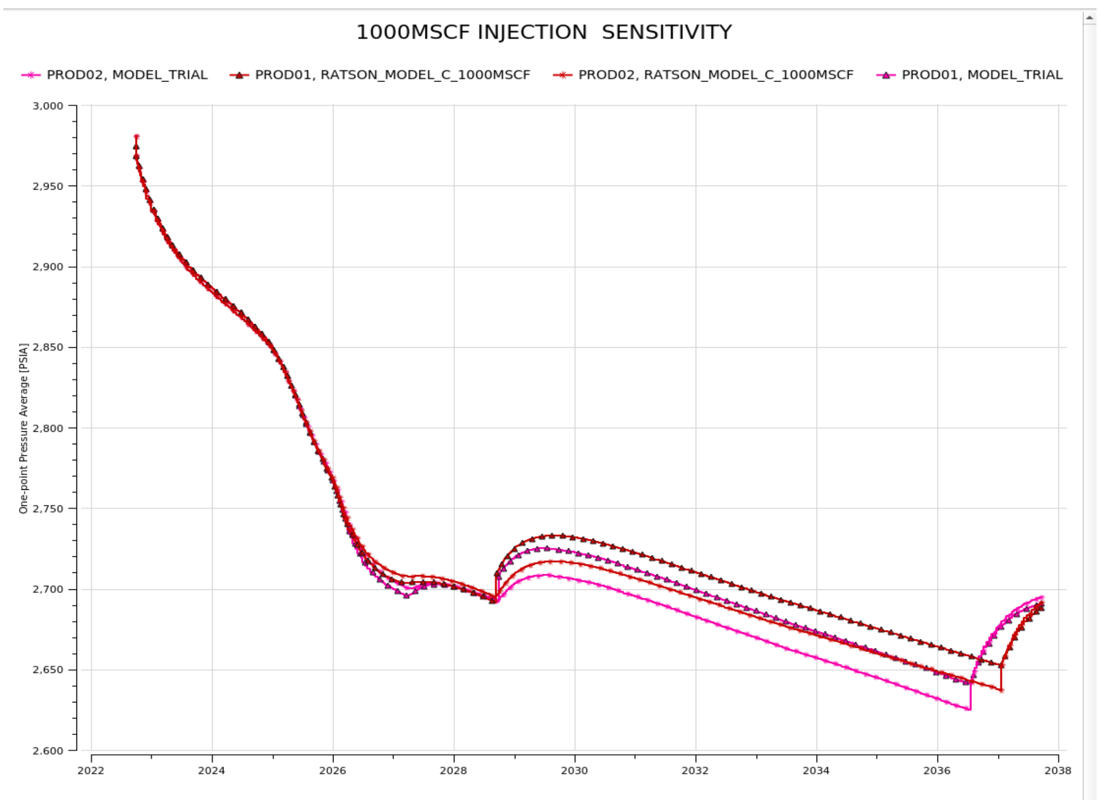

Figure C12: 1000 MSCF WBP Sensitivity Plot

Appendix D: PVT Properties and Niger Delta Geological Timeframe

D.1 PVT Properties Plots

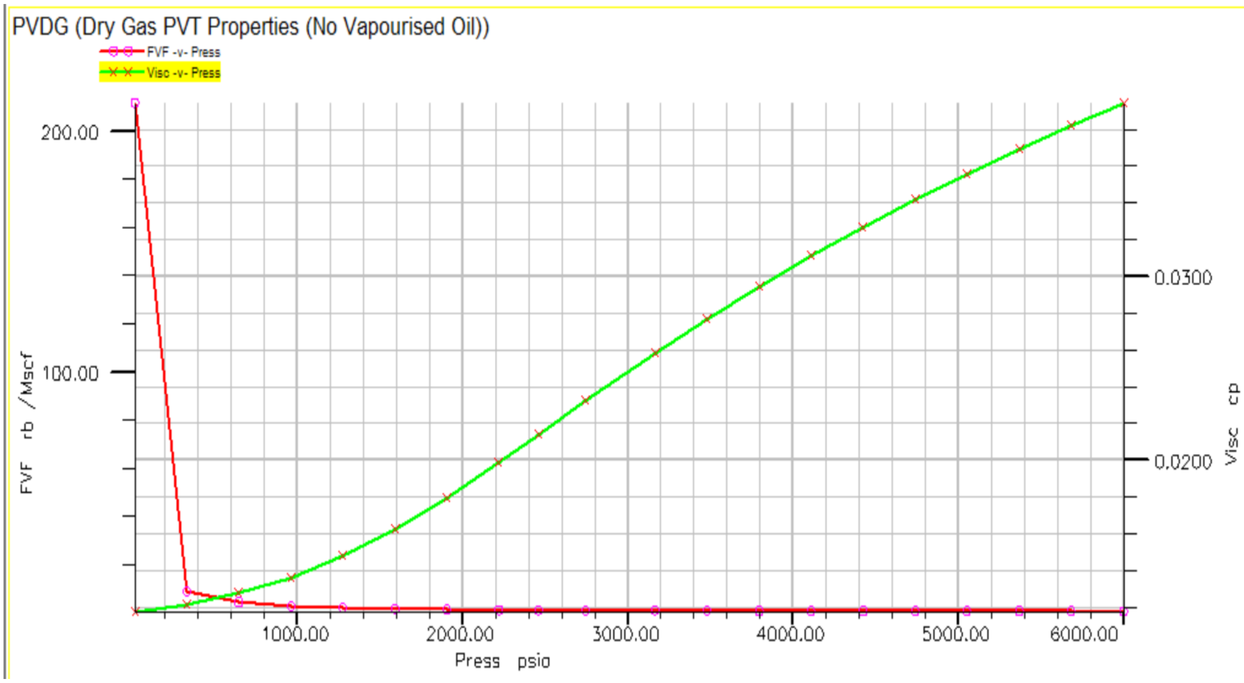

Figure D1: Dry gas PVT properties

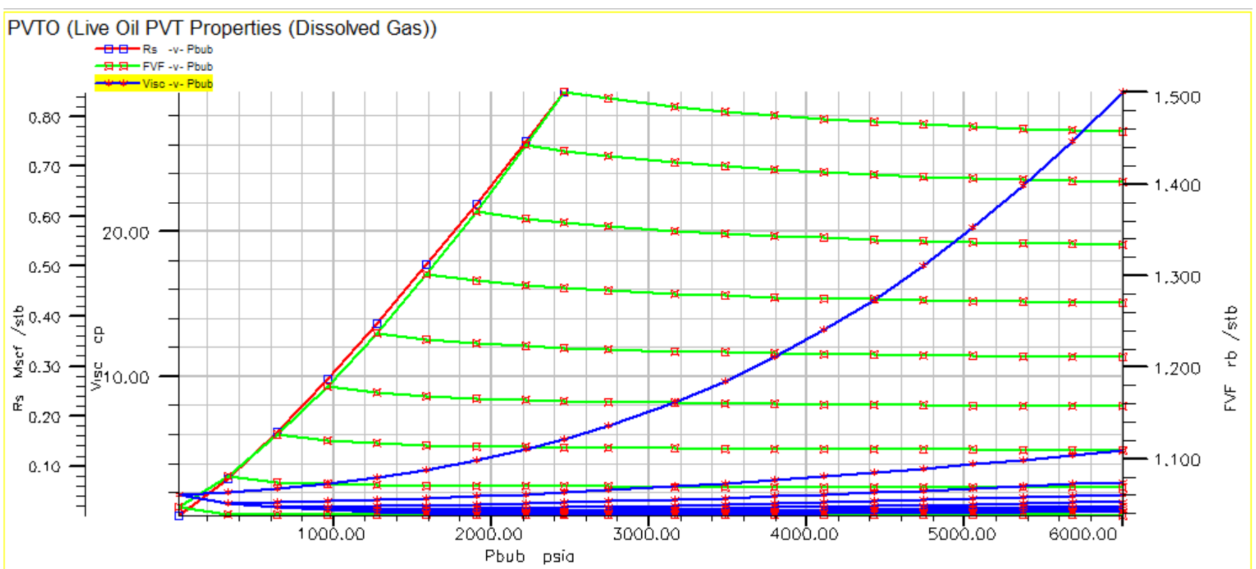

Figure D2: Live oil PVT properties

D.2 Geological Timeframe for Development of the Niger Delta Basin

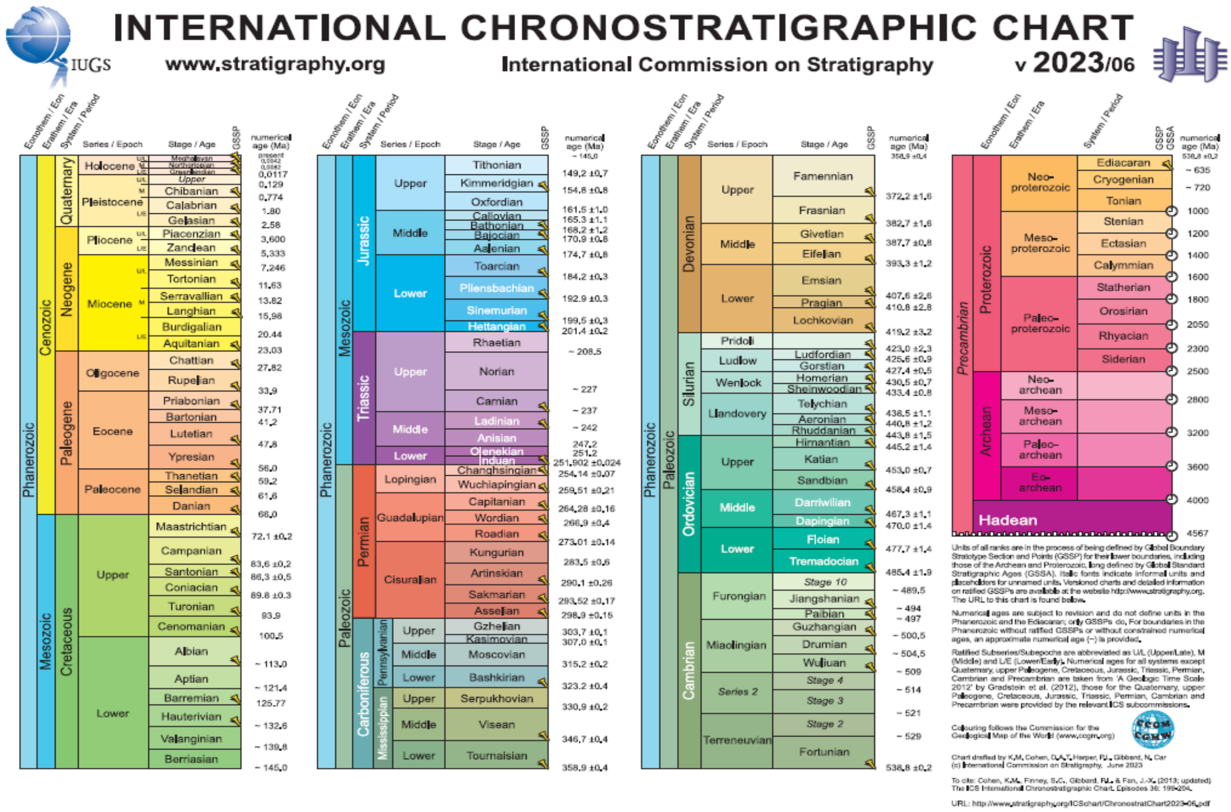

Figure D3: International Chronostratigraphic Chart (Cohen, Harper, & Gibbard, 2023)

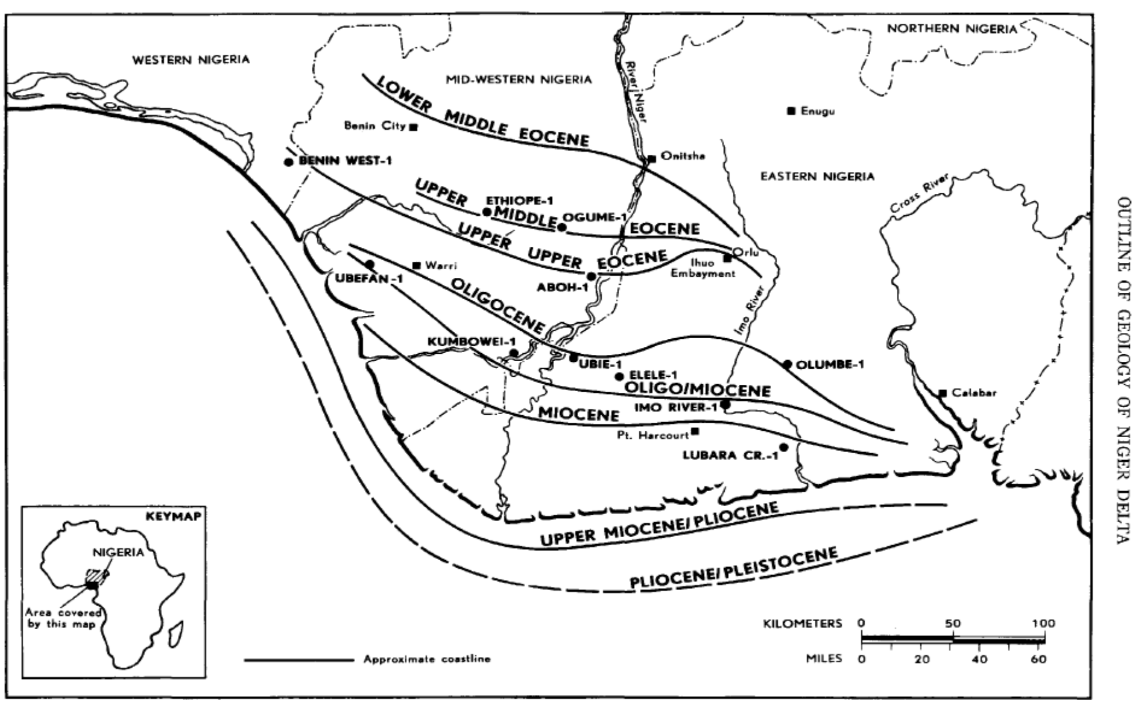

Figure D4: Paleogeography of Tertiary Niger delta—stages of delta growth (Short & Stouble, 1967)