COMPARATIVE STUDY ON A THREE PHASE SYSTEM FOR THE EVALUATION OF WELL PERFORMANCE AND RESULTS

A THESIS SUBMITTED TO THE GRADUATE SCHOOL OF APPLIED SCIENCES OF NEAR EAST UNIVERSITY

By
RAHANAT OSEHEIZA MOHAMMED

In Partial Fulfilment of the Requirements for
The Degree of Master of Science
in
Petroleum and Natural Gas Engineering

NICOSIA, 2020

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Approval of Director of Graduate School of Applied Sciences

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We certify that this thesis is satisfactory for the award of the degree of Masters of Science in Petroleum and Natural Gas Engineering

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I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

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Date: 04.06.2020

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To my family…

ABSTRACT

The use of computer model has become part of the petroleum industry in the last few decades with an innovative and advanced method in providing better understanding of fluid flow in the reservoir regardless of its complexities. Its use for reservoir simulation modelling requires a concentrated study on the characteristics of fluid dynamics as well as interactions in reservoirs. Completion of well modelling techniques can provide results which when analysed is a method of risk assessment of the reservoir against making costly financial mistakes. Reservoir simulation is often done to provide a company/engineer deeper understanding of the performance of the reservoir. After the goal of the study has been determined by the simulation engineer, the most fitting approach which is subject to the fluid and rock properties is determined before the data is analyzed.

For this research, PROSPER, PIPESIM and CMG was employed for reservoir modelling and production optimization. PIPESIM and PROSPER produced well designs suitable for optimum performance using the data-set available and results were concluded on. Additional optimized production through implementation of ESP lift was simulated. CMG's IMEX for Black Oil models produced detailed information on the fluid flow relationships and predicted oil production rates for the next 30 months. The comparison between productions with and without water-flooding can be seen.

Keywords: Waterflooding; PROSPER; computer models; well modelling; history matching; upscaling.

ÖZET

Bilgisayar modelinin kullanımı, son birkaç on yılda, karmaşıklığına bakılmaksızın rezervuardaki akışkan akışının daha iyi anlaşılmasını sağlayan yenilikçi ve gelişmiş bir yöntemle petrol endüstrisinin bir parçası haline gelmiştir. Rezervuar simülasyon modellemesi kullanımı, akışkan dinamiklerinin özellikleri ve rezervuarlardaki etkileşimleri üzerinde yoğun bir çalışma gerektirmektedir. Kuyu modelleme tekniklerini tamamlanması analiz edildiğinde maliyetli rezervuar hatalarına karşı bir risk değerlendirmesi gibi sonuçlar verebilir. Rezervuar simülasyonu genellikle bir şirkete/mühendise rezervuarın performansı hakkında daha derin bir anlayış sağlamak için yapılır. Çalışmanın amacı simülasyon mühendisi tarafından belirlendikten sonra, gerekli veriler analiz edilmeden önce akışkan ve kayaç özelliklerine tabi olan en uygun yaklaşım belirlenir.

Bu araştırmada rezervuarın modellenmesi ve üretim optimizasyonu için PROSPER, PIPESIM ve CMG kullanılmıştır. PIPESIM ve PROSPER, mevcut veri kümesini kullanarak optimum performans için uygun kuyu tasarımları üretti ve sonuçlar sağladı. ESP pompasının uygulanmasıyla ek optimize üretim simüle edilmiştir. “Black Oil” modelleri için CMG IMEX akışkan akışı ilişkilerinde ayrıntılı bilgiler sağlamış ve takip eden 30 ay için üretim debilerini tahmin etmiştir. Su basması olan ve olmayan üretim arasındaki karşılaştırma da görülebilmektedir.

***Anahtar kelimeler*:** Su Basması; PROSPER; bilgisayar modelleri; kuyu modelleme; tarihçe eşleme; ölçeklendirme.

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LIST OF ABBREVIATIONS

BHP:	Bottomhole Pressure
BWI:	Water Formation Volume Factor
CMG:	Computer Modelling Group
CO:	Under-saturated Compressibility for Oil
CVW:	Pressure Dependence of Water Viscosity
CW:	Compressibility of Water
DOF:	Digital Oil Fields
EOR:	Enhanced Oil Recovery
ESP:	Electrical Submersible Pumps
FVF:	Formation Volume Factor
Gg:	Geothermal Gradient
GOC:	Gas Oil Contact
GOR:	Gas Oil Ratio
IPR:	Inflow Performance Relationship
LGR:	Local Grid Refinement
MD:	Measured Depth
MTBR:	Mean Time Between Repairs
PVT:	Pressure-Volume-Temperature
STB:	Stock Tank Barrel
Sw:	Saturation of Water
THP:	Tubing Head Pressure
TVD:	True Vertical Depth
VLP:	Vertical Lift Performance
VWI:	Viscosity of Water
WOC:	Water Oil Contact

CHAPTER 1

INTRODUCTION

Hydrocarbons which are produced from thousands of feet below the surface of the earth have been generated and accumulated from organic matter over time. The accumulated oil and gas can be most likely be detected in a reservoir rock that has the ability to push out enough petroleum into the producing surface area. To produce hydrocarbons to the surface facilities, a well must be drilled into the reservoir mostly equipped with a casing to hold the well and protect it from the surrounding formation. A tubing which serves as a conduit to the surface is also set. Proper well development practices are to be ensured to provide optimum well deliverability in the best economical range possible. That is why it is important to evaluate well performance by using computer software designed for modelling and calculation of the wells' ability to produce oil and gas effectively at a desirable rate (Karikari, 2010). Good well modelling by using a software involves adequate use of the available reservoir information and establishing a relationship between the size of tubing to be selected, reservoir productivity, and the rock/fluid properties (Tarek, 2010).

Pressure drop in a reservoir is one of the biggest factors influencing the flow of fluid, and as such it is an important factor in the overall financial consideration in a well design. Precise knowledge of the pressure drop in a reservoir serves as a guide for well design, and optimization techniques (Fossmark, 2011). As oil or gas flow from the bottom of the well upwards the pressure declines with continuous production due to friction between the walls of the tubing and the fluid itself, other flow restrictions in the tubing or forces between the rock and fluid (viscous and gravitational forces). Pressure drop in oil reservoirs will lead to escape of gas in oil while pressure drop in a gas reservoir may lead to the formation of condensates.

A well performance modelling done through simulation tools should involve the inclusion of detailed PVT model of the oil or gas produced from the well, the inflow performance curve model and the outflow performance relationship model (Tarek, 2010). Fluids produced at the surface must have undergone several properties at varying temperature and pressure; this is why a PVT model is considered important. Proper PVT model for varying temperature and pressure is applied in well simulation design and optimization to predict fluid flow conditions through tubing (Petroleum Experts, 2010). The calculation of pressure drop of a flow medium is considered complex because as the fluid travels upwards to the surface, the fluids may separate and velocities of gas and liquids travelling up the well will differ.

The prediction of pressure drop is important as it provides an estimate of the fluid volume a well can deliver, thereby improving the reservoir time to depletion. There are various multi-phase flow correlations proposed although none has been confirmed to provide accurate prediction for all circumstances that may come up during production. The applications of various correlations have a practical meaning for which their individual use is based upon by modelling the pressure losses (Pucknell et al., 1993; Fossmark, 2011). The best approach is to examine all the correlations and then compare them to select the best one with the available data for modelling fluid flow (Brill and Mukherjee, 1996). For this study, the correlation used for the modelling is modified by tuning the software to provide precise correlations which is then used in forecasting the performance of the well.

1.1 Fundamentals of Reservoir Fluid Flow

For a well to flow preferentially, the two areas of importance studied are the pressure change along the path through which it flows and the pressure relationships at the important nodal points. The important variables taken into consideration are the reservoir pressure, wellhead pressure, stock tank pressure, bottomhole flowing pressure, and the separator pressure for their equivalent rates of oil or gas production. The reservoir pressure differential is the main force that aids substantial flow into the wellbore and increases the rate of production as the reservoir drawdown pressure increases. In a simple plot normally referred to as the Inflow Performance Relationship (IPR) curve, a clear relationship between the surface oil and gas rate and the wellbore is formed. Well productivity is influenced by the IPR through nodal analysis. Nodal analysis provides a view on the inflow rate of fluid performance of the well with its outflow curve. These two plots are then combined to create a single graph showing an intersection point for managing a well’s producibility.

1.2 Production Optimization

Production optimization through well control and software implementation are important factors in the petroleum industry which helps to create a round assessment of how the maximum capacity can be reached with minimal risks involved. This problem is highlighted because there are so many oil fields in their mature stages compared to the number of new oil pool discoveries. Many engineers are then faced with the task of managing the available mature field in order to produce to its highest capacity through the control of wells and reservoirs. A well is a connection between the reservoir and the surface and thus should be considered as a boundary point. The volume of oil or gas produced is highly dependent on the flowing bottomhole pressure, which can be changed through the use of valves installed.

Production optimization in wells can be achieved by adopting the following practices:

- Ensuring well integrity by prevention or remediation of casing and cement failure.
- Removing damages near the wellbore by matrix stimulation (acidizing)
- Conformance management practices (fingering and gas/water coning problems) near-wellbore area.
- Designing well completion optimization through sand control management and artificial lift performance.

The most important goal of production optimization is to ensure well productivity which is influenced by inflow performance relationship curve through nodal analysis. Nodal analysis is important as it helps to analyze the performance of the surrounding system composed of the interacting components between the inflow production rate and inflow pressure with the outflow production rate and outflowing pressure at node. The point of intersection between an inflow performance curve and outflow vertical curve is known as the flowing point.

1.3 The Scope of the Thesis

The aim of this thesis is to evaluate the results from the comparative study done by using intensive datasets available, to determine the producibility of one well completed at different intervals. Chapter 1 is the introductory section providing a brief explanation on the fundamentals of fluid flow through a porous medium, and the importance of production optimization in the industry.

Chapter 2 comprises literature review on the mathematical equations governing fluid flow, performance checks for well modelling/production, artificial lift use in the industry for optimization, and recent developments in Petroleum Engineering.

Chapter 3 highlights the importance of reservoir simulation, the significance of this study done by using computer simulation software, statement of the problem, description of data and general information on the methods adopted to complete the research.

In Chapter 4, detailed explanation on the use of CMG's IMEX simulator for evaluating the performance of one well for a period of 30 months at scheduled flow rates over time, model assumptions considered and validation is done. Related variables influencing the well conditions are compared in different scenarios to determine the most suitable conditions for optimum delivery.

Chapter 5 shows through nodal analysis how well performance can be affected by changing tubing size, outlet pressure and the IPR/VLP relationship curves.

Lastly, Chapter 6 concludes on the research study and provides recommendations following the comparative analysis done for this study.

CHAPTER 2

LITERATURE REVIEW

As the demand for various energy forms increases, more weight is being placed on fossil fuels, particularly oil and gas which contributes a large energy production percentage when compared to wind energy and solar energy (Khayet, 2013). Due to the increasing world demand for energy as versatile as the petroleum and natural gas sector, Petroleum Engineers are burdened with expanding production and petroleum output in the market (Lee, 2005). In order to increase production, methods leading to discovery of reservoirs are implemented.

2.1 Mechanisms for Improving Production

Reservoir production process through natural flow aided by means of differential pressure existing between the reservoir and the production well is known as “primary recovery” (Lyons, 2009). After production is completed by natural flow towards the wellhead, the use of secondary recovery processes like gas injection and water-flooding is done to maintain the pressure in the reservoir. In the lifetime of many reservoirs, it may reach a point where it is considered uneconomical to continue production by primary and secondary production only (Lake et al., 2014).This is due to the increased cost added to production as an increased water cut or gas oil ratio simply means there will be need for more surface separation facilities to be used. Production is then continued by introducing tertiary recovery processes also known as enhanced oil recovery (EOR) methods into the reservoir to improve reservoir and fluid properties (Green and Willhite, 1998). When all other options evaluated prove to be economically non-feasible, the well may then be abandoned.

The importance of petroleum engineering industry in the past decades cannot be overemphasized. An exceptional disciple which not only prepares petroleum engineers studying the discipline on the core aspect of crude oil formation and extraction, but also on various training of an everyday general engineer. A Petroleum engineer undergoes basic learning courses considered important for other disciplines such as geology, chemical or even mechanical engineering. Initial migration is where the hydrocarbons readily move to the more porous, permeable and low pressured area, after which the hydrocarbons move upwards to a trap formed by means of gravity segregation (Djebbar and Donaldson, 2004). One of the basic sectors thriving in the oil and gas world is the reservoir engineering aspect which holds the brain power to all the exploration and technical production studies. Reservoirs are where hydrocarbons can be found containing organic compounds with various behavioural pattern due to their individual pressure and temperature (Tarek, 2001).

2.2 Reservoir Fluid-Flow Properties

To better understand the behaviour of the reservoir, the use of field data, flow models, structural mathematical models to forecast producible zones for oil and gas exploitation or reservoir characterization can be summed up as processes reservoir engineering. The single most important reason for reservoir characterization is to determine the basic reservoir properties associated with the field and finally to be able to find out the most suitable method for optimum producibility production.

Knowledge about diffusivity equation as well as differential equation like non-linear partial differential equation is used in forming numerical reservoir simulation (Schlumberger, 2001). This process puts into consideration the behaviour of the rocks in presence of reservoir fluid and thus, it is highly important to manage the petroleum assets available today. Helmy et al. (2010) described the “ultimate goal of a reservoir model to be one with a realistic tolerance range for imprecision and uncertainty that may arise”. The importance of reservoir characterization involves the modelling of every unit involved to provide realistic well behaviours and the use of previous history of well performances to predict future conditions of the reservoir. This is accomplished by the combination of discipline information from geology, geophysics, reservoir engineering, petroleum economics, petroleum production engineering and often use of petrophysical information (Aminian and Ameri, 2005; Wong et al., 2005).

These days, reservoir interpretation, reservoir modelling and fluid flow in reservoir studies are used in the prediction of production performance, and forecast on cash flow in business decisions (Cavero et al., 2016). In a three-dimensional reservoir modelling, some limitations that may start from allocation of the selected facies with their individual properties and integrating the adjacent and vertical selection in the required range within all flow elements in the selected 3-D framework (Orellana et al., 2014). This process involves the use of conceptual geologic models (CGM) in the combined three-dimensional reservoir model by use of correct geostatistical techniques (Orellana et al., 2015). Geologic models show a good representation of geological parameters and serve as a principal guide in developing three dimensional models at various points during oil exploration and production projects by using factual or theoretical geological objects and processes (Quinto et al., 2013).

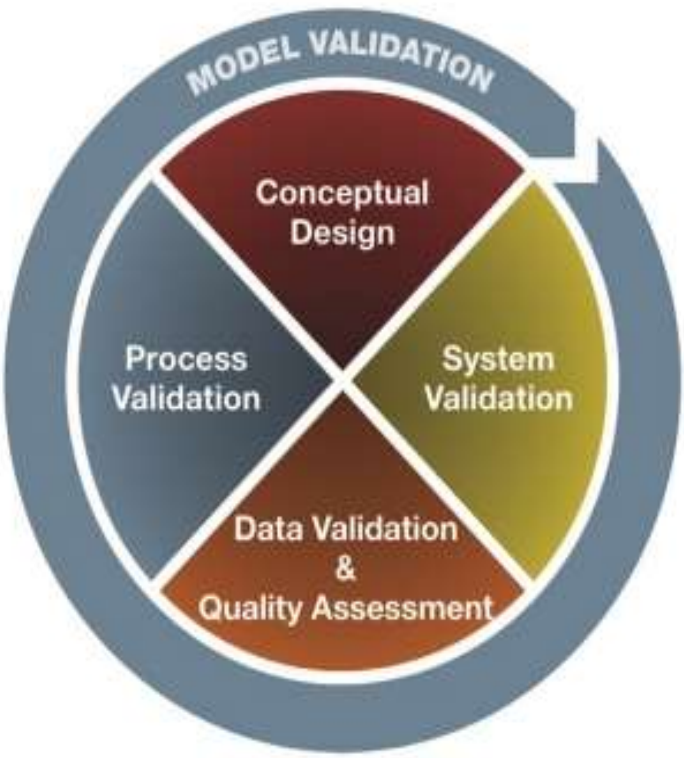

Figure 2.1: Model validation using four main components (Crowe, 2016)

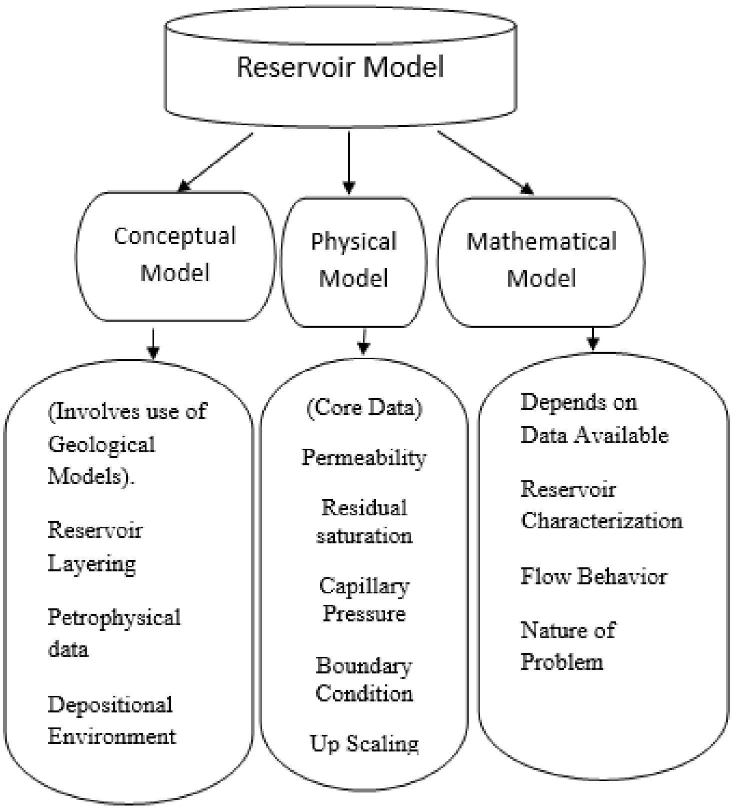

Figure 2.2: Reservoir model (Wall, 1986)

2.3 Mathematical Principles and Laws Followed by Reservoir Simulation

Some of the laws followed by reservoir modelling tools are:

- Conservation of mass
- Conservation of energy
- Conservation of momentum

Their use and application in reservoir engineering are highlighted in the following paragraphs

2.3.1 Mass conservation

The principle of this law explains that for every system closed to transfer of energy, the mass of that system must be constant by time. This is because the mass of any system cannot change therefore no quantity can be added or deducted from it i.e. the value is preserved over time (Wikipedia, 2019). Flow through various porous media is based on mass and energy preservation, and derived for the fluid type as well as the porous material used. The conservation of mass can be described in the well-known formula below in Equation 2.1:

⟨Mass in system "x"⟩ - ⟨Mass out of system "x+Δx"⟩= ⟨Rate of mass change in system⟩

$$u\rho A_{x} - u\rho A_{X+\Delta X} = \frac{\partial}{\partial t}\{\varphi A \Delta x \rho\} \qquad (2.1)$$

Where:

u = Velocity (m/s)

ρ = Fluid density (kg/m^3)

A = Cross sectional area (m^2)

2.3.2 Conservation of momentum

Conservation of momentum is derived from Newton's First Law of Inertia which states that a system will have a constant momentum with no external force acting on the system (Feynman et al., 1989). The conservation of momentum is ruled by another equation i.e. (Navier-Stokes) but often reduced for a low velocity flow in porous media which is shown in form of Darcy's equation in a horizontal flow (single phase). It can be described mathematically as shown in Equation 2.2:

$$u = -\frac{k}{\mu}\frac{\partial P}{\partial x} \qquad (2.2)$$

Where:

u = Velocity (m/s)

k= Permeability (md)

μ= Viscosity (cp)

2.3.3 Conservation of energy

The conservation of energy states that energy can neither be created nor destroyed instead it moves from place to place and changes from one form to another. The energy is assumed to be preserved over time hence the name "conservation of energy. It is known as the First Law of Thermodynamics and the foundation of most flow equations known. In friction losses during heat and fluid flow surroundings at steady state, mass conservation provides a simple expression for pressure gradient (Ikoku, 1984; Katz and Lee, 1990).

$$\left(\frac{dP}{dL}\right)_f = \rho \frac{d\,(lw)}{dL} \tag{2.3}$$

Where:

P = Pressure (lb_f/ft^2)

ρ = Fluid density (lb_m/ft^3)

l_w = Heat loss during work converted ($ft\text{-}lb_f/lb_m$)

L = Length of pipe (ft).

2.3.4 Well performance models

A well performance model is designed to provide visual and systematic understanding of a well design. It provides possible alternatives to evaluate a well production pattern, its performance and completion pattern which aids the prediction of well performance depending on its varying reservoir characteristics. Well models consist mainly of:

- Modelling of fractured zones
- Well completion design and assessment
- Inflow performance analysis
- Liquid fall-back analysis
- Production prediction
- Heat flow evaluation in the wellbore
- Artificial lift design/Lift performance
- Financial evaluation.

An added importance of simulation models is the use of primary recovery methods to ascertain the performance of artificial lift methods in wells. Simulations based on the field data will give an indication of what rates the different solutions will give. Production wells are either free flowing or lifted. A free-flowing oil well has enough downhole pressure to reach the suitable production pressure of the wellhead, which gives flow that can be maintained. If the formation pressure is too low, and water and gas injection cannot maintain pressure, then the well must then be lifted artificially. Artificial lift is a means of reducing bottomhole pressure so that a well can produce at some desired rate, either by injecting gas into the producing fluid column to reduce its hydrostatic pressure, or using a downhole pump or sucker rod pumping unit at the well head to provide additional lift pressure downhole. It is not unusual to associate artificial lift with mature, depleted fields, where reservoir pressure has declined such that the reservoir can no longer produce naturally. These methods are also used in younger fields/marginal fields to increase production rates and improve project economics.

2.4 Artificial Lift

Artificial lift is a process used in oil producing wells to increase displacing pressure differential within the reservoir and encourage oil to flow towards the surface. When the natural drive energy of the reservoir is not strong enough to push the oil to the surface, artificial lift is employed to recover more oil. Artificial lift technologies are of many types and specifications. In this case, it applies to numerous methods equipment's, instruments, technologies and techniques used to improve the flow of fluids (like crude oil, water or a mix of oil and water along with natural gas) from a production well. The lift can be achieved mechanically through the use of a pump.

It can be as simple as to change the well's natural flow pattern by installing a velocity string. Alternatively, lift can be achieved by decreasing the weight of the hydrostatic column in the well by injecting gas into the liquid at the designed depth. This course will review the major types of artificial lift systems, explain benefits and drawbacks of each type, and what are the ideal applications for each.

2.4.1 Importance of artificial lift in production optimization

In artificial lift operations, operators are interested in increasing their production while minimizing the cost to do so. In order to achieve both, the need to implement proper planning to avoid poor performance is necessary.

In dealing with mature fields it's not unusual that difficulties related to field productivity is encountered where artificial lift is a method that can be implemented to get full recovery for the wells/fields. Regardless, it is important to select the best method of lift for the job.

Recent developments include a well test optimization algorithm (well-done) that analyses test separator measurements in real time. Another area of innovation is online, multiphase production measurement using simple instruments. Field tests have shown that the liquid production of a well can be estimated from the pressure drop (ΔP) across an existing flow line restriction, the ΔP can be used for enhanced well scheduling and for measuring the response of gas lift wells to changes in lift gas injection rate. In a new development, gas wells which show changing behaviours can be stabilized by active control of the production choke. Currently, it has been demonstrated in the laboratory and is undergoing field trial.

Generally, production optimization is what an everyday asset management team tries to achieve and it may be straight forward if the well is a natural producing one but it becomes more challenging if the wells need artificial lift which means increased water production as well as increased operating cost. E.g. a well performance optimization was done by Shell using an online, real time software package for monitoring gas lift systems & associated gas lift wells to maintain stable pressure & optimum delivery of the gas to the well by performing automatic distribution of gas. The software package is one of the designed programs under Shell Online Foundation System (SOFS) (Cramer et al., 1997). It is important for the operators to remember to take several necessary steps to acquire good well test data, since well testing is a vigorous and time-consuming process. An increasing number of consumers will be using artificial lift optimization solutions that depends on the connectivity, real-time monitoring, which gives itself to the geographically distributed and infrastructure limited nature of upstream production assets onshore, offshore, and subsea. In these applications, one or more operating companies can benefit by sharing operational data across the field or large reservoir.

The initial well planning process should consider the deployment of artificial lift systems, and realizing that at some point in the well's life cycle, it's more likely that artificial lift optimization will also have to be deployed. Lift requirements should be based on the overall reservoir exploitation strategy and will have a strong impact on the well design. While numerous factors influence the selection of an appropriate artificial lift method, it's clear that the use of artificial lift optimization solutions is necessary to ensuring owner-operators players and drilling contractors can maximize their production, improve recovery rates in new wells, enhance oil recovery in more mature wells and open up the production envelope in a broader array of well types and application locations. In marginal fields where there are some technical limitations due to smaller recoverable reserves, low permeability and thickness the use of artificial lift can be implemented although selection from a wider range of method is limited due to its size. Some artificial lift methods considered in many field operations are Sucker-rod Pumping, Electrical Submersible Pumps (ESP), Progressive Cavity Pumps, Hydraulic (Turbine Pumps and Jet Pumps), and Gas Lifts.

Gas Lift is the most common type of lift used in onshore and offshore wells. The gas lift is not a favourite in lifting of heavy oil due to high solution GOR. Gas lift is favourable for offshore locations mainly because of its rate flexibility, high Mean Time Between Repairs (MTBR) and Retrievability.

2.5 New Developments in Petroleum Engineering

The oil and gas sector today is much different from what it used to be in the1960's. With innovations and technological advancement since then, vast improvements have been attained in the fast moving industry, creating an environmentally safe and reliable energy sector equipped with the knowledge to reduce the effects on the climate (NORSK, 2019). The application of research studies, development designs and clear demonstration of new technology has been essential to the thriving petroleum industry in the last few decades. The use of progressive methods in oil and gas fields around the world is implemented to help in the identification of new reservoir regions for development and ultimately help in the production of oil/gas efficiently and safely. These new developments are required for solving existing and future problems that may arise in the industry.

The petroleum sector is the one that constantly reviews methods and designs for future development to compete with other sources especially the growth in the renewable industry. Some of the new developments recorded include the use of rock simulators like the coupled flow and rock mechanics simulator which is used to design and provide production forecasts from reservoirs with considerably weak or medium strength (Pettersen, 2012). The coupled flow-simulator provides an accurate compaction computation in many reservoirs considered to be weak.

Another area of improvement is in the highly technical hydraulic fracturing job which involves forcing open formations with oil or gas due to their difficulty in producing naturally. Hydraulic fracturing is done through the use of water (pressurized), chemicals and proppants. Fracking in shallow zones can pose series of threats to the environment and aquatic habitat through migration of harmful chemicals which have been used into water-bodies (Marten Law, 2013). Some of the milestones attained to preserve environmental safety is the introduction of legislative/regulatory laws by the government and related bodies to mitigate the impacts of hydraulic fracturing on the environment (Hall, 2013).

CHAPTER 3

METHODOLOGY

The use of computer model has become part of the petroleum industry in the last few decades with an innovative and advanced method in providing better understanding of fluid flow in the reservoir regardless of its complexities. It promises a concentrated study on the characteristics of fluid dynamics as well as interactions in reservoirs. Completion of well modelling techniques can provide results which when analyzed a method of risk assessment of the reservoir can be developed, reducing the risk of financial mistakes.

Numerical Reservoir Simulation is a combination of reservoir engineering, mathematics, physics and also computer programming to device a means for predicting the reservoir and well performance which is operating under certain conditions. In the past, physical models were used to simulate the reservoirs. These models made use of the interaction of water, oil and sand in order to simulate the reservoirs. Then, the use of electric simulators was introduced. In this method, the use of electrical current flow and reservoir fluids were used to predict the behaviour of the reservoir. In the last four decades, the use of computer technology has made numerical reservoir simulation a lot better by allowing the simulators used for reservoir modelling to have more realistic and more accurate predictions.

Petroleum engineers need numerical reservoir simulation in order to get a more precise and accurate prediction of a hydrocarbon reservoir performance. This helps in minimizing the risk that may occur in the reservoir life thereby improving the efficiency of the reservoir. Risk in the reservoir is affected by several factors such as the complexity of the reservoir due to anisotropic and heterogeneous properties, differences in fluid properties in the different zonal areas of the reservoirs, difficulty in the hydrocarbons mechanisms due to complexity and also the application of alternative prediction methods which have limitations that might be unsuitable or inappropriate for the reservoir. Numerical reservoir simulation takes all of these factors into consideration by the general input data initiated or built in the reservoir simulation models to ensure its validity.

Numerical reservoir simulation study is more than just simulating some runs on a model and concluding the study based on the output, in fact, it is much more equipped to provide the engineer deeper understanding of the performance of the reservoir. After the goal of the study has been determined by the simulation engineer, the most fitting approach which is subject to the fluid and rock properties is determined before the data required is analyzed. Another important process in reservoir simulation involves the preparation for computer runs. The final step involves the examination of the output gotten as well as the preparation of the report.

With each passing decade more limiting factors are present in most reservoirs and wells which cause delay or difficulty in extraction of hydrocarbon. It was found that most reservoir engineers follow a trial-error pattern in order to translate the data available, that is, core analysis, production history data, seismic data and well log data into more useful information for engineers. The use of simulation model is introduced to experiment the different dynamics of fluid flow through porous media in reservoir. The use of these models is to correlate the pressure response to each producing level which can ultimately create a 2D/3D view of production in any similar field with the same characteristics. Since the use of numerical modelling are not viable for fields with large data (problem) and it is in fact technically expensive to complete, the use of the aforementioned reservoir tools which can perform multiple runs for sensitivity analysis and design optimizations to be done is highly preferred.

3.1 Significance of the Study

Over the last decade, numerical reservoir simulation has been developed in variations and qualities that suit the properties of a reservoir, and that is why this study is important as it tends to the increasing need for petroleum engineers to provide correct forecast of the performance in reservoirs under varying conditions. Often, the recovery of hydrocarbons from a field/reservoir is backed with an even bigger financial risk that the company will be taking. A very large investment indeed, with millions of dollars at risk if the recovery plans is not fruitful. While a reservoir engineer cannot afford to make mistakes in their predictions and calculation of performance value, numerical reservoir simulation model is one method that can be relied upon to provide accurate information on a reservoir or well condition provided trusted data is available from the field that can be matched to. Possible risks realized after modelling a reservoir through simulation must be assessed and mitigated to the lowest in order to determine if the project will be completed or dis-continued. This is usually done by completing an economic analysis of the project at the end of the reservoir simulation by the geologist or engineer. Some of the issues that contribute to high risk situations in a reservoir are the nature of the reservoir in terms of complexity, recovery mechanisms of the reservoir, fluid properties, relative permeability characteristics and the use of procedures with limitations that may lead to error. The last factor can be mitigated with time as the engineer gets used to the reservoir simulation model and frequent use of everyday engineering practices.

3.2 Reservoir Modelling

In order to introduce the use of reservoir models, data functions such as Petro-physics, fluid properties, well data, facilities, tubing curves and seismic data interpretations must be incorporated (Fanchi, 2006). The modelling of reservoirs simply implies the application of computer modelling tools to describe the flow of fluid in the reservoir and by such analysis, provide a better understanding of processes in the reservoir (Aziz & Settari, 1979). These computer programs help in the design of flow patterns in the porous media albeit providing possible solutions to challenges that may exist in such reservoirs. In other words, reservoir modelling computer tools are like an assessment system used in the management practices that aid optimum recovery of hydrocarbons while considering the economic implications as a reservoir engineer (Fanchi, 2006).

Reservoirs can be defined in discrete areas associated with various properties along with them. The relationship between the pressure and saturation components in the form of non-linear differential equations can be created and then solutions can be provided using the finite difference method equation. This is how reservoir models and simulating models make use of numerical solutions to solve the aforementioned equations (Wall, 1986). Although a model formed may not be an exact replica of the reservoir, the end result greatly depends on the availability and quality of data to be used. The Figure 2.2 in Chapter 2 describes a typical flowchart on the inputs required for a reservoir model.

3.2.1 Importance of reservoir simulation

Forecasting the performance of reservoirs must be done as accurately as possible to avoid making financial errors. The simulation process can be done by the implementation of calculations using the finite difference equation (Dullien, 1992). It was found that the main reason reservoir simulation studies are carried out is to present a trusted forecast of a reservoir's performance and its highest possible recovery (Aziz & Settari, 1979). It is important to ascertain the goal and objectives of the study to be carried out before the start of reservoir simulation. Carlson (2003) mentioned that some procedures required before an ideal reservoir simulation can be carried out are the review of all geological information available, review of present reservoir performance, data collection, model selection, initializing, history-matching, forecasting and then recording the output.

1) ***Available Geological Information:*** Geological reviews are so important because they provide information on all the connections to the geological model that may be used in understanding the reservoir's pore geometry (Carlson, 2003).
2) ***Review of Reservoir Performance:*** The performance of the reservoir is an important process for reservoir simulation as it provides information on several parameters needed to follow up. Parameters such as Pressure-Volume-Temperature (PVT) data, the driving mechanism of the reservoir, the reservoirs Gas Oil Ratio (GOR), and Formation Volume Factor (FVF).
3) ***Data Collection and Model Selection:*** All data available must satisfy the quality checks of the distributing reservoirs fluid and rock properties (Carlson, 2003). The selection of model is subject to the data available and field properties required. When quality data is provided, several models may be useful for the simulation process. In any case of a new design required, a model may be updated or adjusted as desired.
4) ***Initializing:*** Involves run simulations that generate values for the initial water in place, initial gas in place as well as oil in place (Carlson, 2003). Initializing the fluid in place is affected by the rock type and location.
5) ***History-Matching:*** Carlson (2003) described history matching as the inputting of various reservoir properties relevant to that reservoir in the past, in order to verify that the selected models are working excellently as intended. Validating a model involves for main procedures and also highlights possible restrictions, uncertainties and their effects.

History matching can be done by regulating the input data until a more suitable result to the exact performance of the reservoir is achieved. The deviations and problems reflected in the model should equally be as depicted in the reservoir. Parameters that can be adjusted during this procedure are volume of water cut, pressure, field inputs and wells (Panteha, 2018). History matching is particularly useful when a field is mature as it has previous information's that will aid production assessment.

6) ***Forecasting:*** Forecasting the performance of the well or reservoir is next after validating the model, finding the OOIP and OGIP and history matching the reservoir model. The performance of the reservoir model can be forecasted at various scenarios by using various properties associated with the well. The output retrieved are then examined carefully to predict a possible future performance depending on the expertise of the engineer in charge of the model simulation (Carlson, 2003)
7) ***Recording the Output:*** Recording the findings made during simulation modelling is the last step. Simulation models are set up in such a way that the engineer always comes back to his work to achieve the exact performance needed. After the discretization on each grid block, properties of a single grid can be found and solved using a finite difference solution method. In another solution method known as the streamline solution, equations are solved on each grid. Ordinary functions can be used to find solutions for restricted elements (Schlumberger, 2001). After forecasting the performance of a well or reservoir, decisions on how much to be invested can be done through other simulation although it depends on the ability of the intended model to be used (Jian and Larue, 2002).

The use of diffusivity and non-linear and partial differential equations can be introduced in reservoir simulation projects when data is readily available on the rock and fluid measurements. Various rock data can be determined from carrying out tests like drill stem tests, logging and analyzed in the laboratory (Dullien, 1992; Schlumberger, 1972). Reservoir simulation and modelling of well or reservoir is such a huge breakthrough for the petroleum industry as it has cut down the time used in making such calculation the models can perform in a few runs. It provides a non-tedious method in gaining information about the reservoir and forecast on the performance. Through this information, possible perils can be reduced or averted thereby improving the development of the well / reservoir.

Some of the biggest problems associated with reservoir simulation are:

- Data collection
- Reservoir properties (thickness, and areal extent)
- Little knowledge on reservoir mechanisms / complexity. (faults, distribution, facies).
- Error in recorded fluid properties i.e. viscosity and formation volume factor.

3.2.2 Possible problems involved with simulation

Finding an authentic data to be used for the simulation can be difficult since it has to be released by oil companies or approved for individual use. In other instances, insufficient information of the data can also prove to be a problem for the engineer. It is highly important to use a correct data, as the data should describe the reservoir accurately. Sometimes, true data values can only be verified through drilling process. The use of an incorrect data will most likely defeat the purpose of simulation modelling anyway. Secondly, accurate information on reservoir properties can be a problem when the midpoint is used and its values inputted into the model which then changes the result or performance totally. Better performance can be achieved through upscaling of the formation properties. Upscaling also called "homogenization" involves changing a heterogeneous property area in the model that consists of finer grid cellblocks with another homogeneous area consisting of coarse grid cellblock with an active value. The two heterogeneous areas should be equal. It can be done for all the grid reservoir properties needed as well as the coarse grid required for the simulation model. Lastly, there are many reservoir recovery mechanisms although it may be unknown to the geologist or engineer modelling the field. In case of no information on the mechanism of recovery, nearby fields can be investigated upon for an idea on what recovery drive is.

3.2.3 Importance of using reservoir simulation

Reservoir simulation can be used in defining a reservoir as accurately as the data entered, giving the user a visual representation of what the reservoir looks like or how it may perform under varying conditions.

Generally, reservoir simulation can be used for the calculation of volumetric original oil or gas in place estimations by calculating important fluid saturation properties like water saturation (S_w). The use of reservoir tools can also be used in the evaluation of reservoir performance, thereby creating an avenue to determine the best recovery method and ultimately determination of techniques to optimize recovery process. Well planning and development practices can be designed through simulation networks for better understanding of the field performance. The use of these computer tools helps in the evaluation of results depicting production profiles for the reservoir and the most optimistic perforation zones in a well. Probabilistic description for the modelled reservoir or well can be generated provide information on injection rates and time in the well.

In reservoir simulation, usually the availability of data regardless of complexity and quality will determine the model to be used. Main elements of reservoir simulation are geological description, type of fluid (Compositional or Black Oil), and depletion type. Apart from the listed importance of simulation, it can also help in forecasting money circulation needed (Fanchi, 2006).

3.2.4 Applications of reservoir simulation modelling

Reservoir simulation is quite versatile and can be applied to a field young or mature at any stage in its life. During the early stages, reservoir models can be implemented to provide a cleaner view of the entire design of a field. At a later stage of the field, reservoir simulation models can be used to manage reservoirs since there will be some history data available on the reservoir in order to maximize the production rate.

At this stage, simulation activities involve progressive processes/development of the field, history matching using new available information from past years for better drilling and injection strategy, and re-visit the method of recovery using the new information presented. At a later period, when abandonment possibilities are starting to be considered, reservoir simulation model can be used to study patterns for improvement techniques like innovative drilling technology and possible use of IOR projects (Panteha, 2018).

3.3 Black Oil and Compositional Models

This involves the modelling of hydrocarbons in their respective phases and their various compositions using simulation tools. Phase Behavior Models take into account the fluid properties and equilibrium rise derivations or equation of state to evaluate the composition.

i. ***Black Oil Model:*** Hydrocarbons present for a black oil model is the one whose composition is expected to remain unchanged throughout the simulation process. Black oil models are done with components that have more than one phase whose mixture is considered immiscible in a porous media. Bubble point pressure and the pressure of the oil are both influenced by the surrounding fluid properties in the reservoir. It was found that using a black oil simulation model encourages the gas to be saturated in the other phases. This model can be used in a reservoir with natural depletion drive or water-flooding plus artificial lift recovery processes (Spivak and Dixon, 1973; Panteha, 2018).

ii. ***Compositional Reservoir Modelling:*** A compositional model is the one which clearly recognizes the exact constituents/compositions of oil/gas phases because of the complex nature of the pressure-volume-temperature (PVT) behaviour (Aziz and Settari, 1979; Panteha, 2018).

3.4 Data Collection

Data collection involved the coalition of authentic data depicting the state of the reservoir to be simulated. For this study, the use of reasonably hypothetical data for a cylindrical well consisting of its PVT profile, initial condition and production chart is given in Table 3.1.

Table 3.1: Well PVT data

Pressure Psia	**Oil Formation Factor B_o rb/stb**	**Oil Viscosity μ_o cp**	**Solution Gas/Oil Ratio (GOR) scf/stb**	**Gas Formation Factor B_g mcf/stb**	**Gas Density ρ_g Ib/ft^3**	**Gas Expansion Factor Eg**
400	1.0120	1.17	165	5.90	2.119	169.492
800	1.0255	1.14	335	2.95	4.238	338.980
1200	1.0380	1.11	500	1.96	6.379	510.204

1600	1.0510	1.08	665	1.47	8.506	680.272
2000	1.0630	1.06	828	1.18	10.596	847.458
2400	1.0750	1.03	985	0.98	12.758	1020.41
2800	1.0870	1.00	1130	0.84	14.885	1190.48
3200	1.0985	0.98	1270	0.74	16.896	1351.35
3600	1.1100	0.95	1390	0.65	19.236	1538.46
4000	1.1200	0.94	1500	0.59	21.190	1694.92
4400	1.1300	0.92	1600	0.54	23.154	1851.85
4800	1.1400	0.91	1676	0.49	25.517	2040.82
5200	1.1480	0.90	1750	0.45	27.785	2222.20
5600	1.1550	0.89	1810	0.42	29.769	2380.95

Other reservoir data used for the simulation are shown in Table 3.2.

Table 3.2: The general PVT data

General PVT Data	**Retrieved Value**
Reservoir temperature	180 ^{0}F
Stock tank oil density	45 lb/ft^3
Gas density	0.702 lb/ft^3
Water density	63.02 lb/ft^3
Under-saturated oil compressibility (CO)	0.00001 psi^{-1}
Water formation volume factor (BWI)	1.01303
Water compressibility (CW)	0.000003 psi^{-1}
Reference pressure for water	3600 psi
Gas viscosity	0.013 cp
Water viscosity (VWI)	0.96 cp
Pressure dependence of water viscosity (CVW)	0 cp/psi

Well deviation data: Well deviation and geometry data retrieved determine the shape and size of the wellbore extent from the initial stages of simulation which ultimately affects how much production the grid type of the reservoir contains.

For reservoir modelling to be done, the first input parameters required will be the basic geometry values for that reservoir. Table 3.3 shows geometry data for the simulation process completed using CMG.

Table 3.3: Basic geometry data

Data Type	**Measured Value**
Radial Extent (ft)	2050
Wellbore Radius (ft)	0.25
Angular theta in horizontal direction	10
Radial position of first block centre (ft)	0.84
Number of radial blocks	10
Radial block boundaries (ft)	0.365632, 0.90038, 2.21721, 5.45995, 13.4453, 33.1094, 81.5329, 200.777, 494.42 and 1217.5.
Dip-angle	0 degrees
Depth to top of formation (ft)	9000
Number of layers	15

Other required data are gas liquid ratio, reservoir depth and reservoir properties as permeability, skin, area, pay thickness, initial reservoir pressure and temperature.

3.4.1 Initial condition

- P_{ref} (reference pressure) = 3600 psia
- Depth of gas-oil contact = 9035 ft
- Oil pressure at gas-oil contact (GOC)= 3600 psia
- Capillary pressure at the gas-oil contact = 0 psi
- Depth of water-oil contact (WOC) = 9209 ft
- Capillary pressure at water-oil contact (WOC) = 0 psi
- Bubble point pressure = Initial pressure =3600 psia (saturated reservoir)
- Skin factor = 0
- Produced well completed in blocks (1, 7), (1, 8).
- Minimum bottom hole pressure = 3000 psi

3.4.2 Production plan

Time (Days)	Oil Production Rate (STB/D)
1 - 10	1000
10 - 50	100
50 - 720	1000
720 - 900	100

3.4.3 Reservoir properties

The array properties showing measurements from the depth to top of formation 9000 ft are given below in Table 3.4.

Table 3.4: Well array properties

Layer	Thickness	Porosity	Horizontal Permeability K_x	Vertical Permeability K_z
1	20	0.087	35	3.5
2	15	0.097	47	4.75
3	26	0.111	148	14.8
4	15	0.16	202	20.8
5	16	0.13	90	9
6	14	0.17	418	41.8
7	8	0.17	775	77.5
8	8	0.08	60	6
9	18	0.14	682	68.2
10	12	0.13	472	47.2
11	19	0.12	125	12.5
12	18	0.105	300	30
13	20	0.12	137	13.75
14	50	0.116	191	19.1
15	100	0.157	350	35

3.4.4 Fluid saturation data

The saturation data shows the fraction of pore space in which a particular fluid type occupies in a reservoir. The accompanying saturation information is provided in Table 3.5.

Saturation values for the reservoir fluids are given below where the expressions "S_w" and "S_g" used mean water saturation and gas saturation, respectively. Relative permeability to water "K_{rw}" and the relative permeability to gas is given as "K_{rg}". Relative permeability for two phase oil-water is given as "K_{row}", while "K_{rog}" denote the oil relative permeability for gas-oil systems. Capillary pressure between oil and water and oil and gas are given as "P_{cow}" and "P_{cog}", respectively.

Table 3.5: Well saturation data

S_w	K_{rw}	K_{row}	P_{cow}	S_g	K_{rg}	K_{rog}	P_{cog}
0.22	0.00	1.0000	7.0	0.00	0.0000	1.00	0.0
0.30	0.07	0.4000	4.0	0.04	0.0000	0.60	0.2
0.40	0.15	0.1250	3.0	0.10	0.0220	0.33	0.5
0.50	0.24	0.0649	2.5	0.20	0.1000	0.10	1.0
0.60	0.33	0.0048	2.0	0.30	0.2400	0.02	1.5
0.70	0.49	0.0000	1.5	0.40	0.3400	0.00	2.0
0.80	0.65	0.0000	1.0	0.50	0.4200	0.00	2.5
0.90	0.83	0.0000	0.5	0.60	0.5000	0.00	3.0
0.96	0.89	0.0000	0.2	0.70	0.8125	0.00	3.5
1.00	1.00	0.0000	0.0	0.78	1.0000	0.00	3.9

The gas compressibility factor "Z" which is a function of pressure was not given initially; instead, by using the PVT information provided above, "Z" was found to be 0.731 and only increasing slightly as pressure declined.

CHAPTER 4

BUILDING MODELS WITH CMG

A BUILDER is a software simulation tool used in generating input folders for CMG. The three basic CMG simulators i.e. IMEX, STARS and GEM are backed up by BUILDER which is a Windows based software program. With this tool, wide ranges of parameters can be determined by creating access which helps for importing grids, well properties, importing of well production data, generating or importing an existing fluid model, rock and fluid properties as well as the initial conditions. Basically, Builder consists of several tools that make it easier to manage data under varying conditions and examine the data before simulation.

Reservoir simulation with CMG provides a description on how a grid is generated and adjusted according to its conditions/properties to determine the most favourable location for well placement. The different sections of IMEX, GEM and STARS can all be used individually in generating a fluid model (i.e. initialization/adjusting the model and PVT properties). For rock and fluid properties, IMEX, GEM and STARS covers the adjustments of rock and fluid properties, relative permeability (K_r) tables, interpolation and adsorption tendencies. For each of the fluid model generated and the rock and fluid properties, a plot showing a vertical versus horizontal axis of the data will be shown by the BUILDER.

For the initialization and well group control, the three simulators cover the initialization selections available for use while the well and group control cover well editing, well group process control (like rates and constraints). History data for the well can be imported into BUILDER through the production data wizard. All the inputs associated with the well can be monitored which can be generated as well control against time.

4.1 Modelling a Well Using CMG (IMEX)

CMG's IMEX is considered one of the most reliable and fastest traditional reservoir simulators in the world which can be used in complex reservoirs to make forecasts reliably. It is quite common for Reservoir Engineers to implement the use of IMEX to ascertain recovery processes through data available from history matching to primary, secondary and other Enhanced Oil Recovery (EOR) processes into GEM and STARS simulators effectively. IMEX is widely known as a black oil simulator for modelling conventional and unconventional reservoirs. Some features like horizontal well system, comprehensive well management, double porosity/permeability system, local grid refinement (LGR), flexible grid, gas adsorption rate and multi-lateral wells are available in IMEX. Through this simulator group, a wide range of reservoir problems can be located and ultimately combated. In order to carry out more reliable runs at a shorter time, IMEX will be used after history matching to compare all possible recovery methods to produce the most financially rewarding selection.

4.2 Initialization – IMEX

To begin the reservoir simulation process, a fluid type model consisting of bubble point pressure (BP), dew point pressure (DP), reference pressure, capillary rise method for determining equilibrium in the wellbore, contact depth of all fluids, datum depth and reference depth is selected. After selecting a fluid type model, the data available on the current state of the reservoir is entered into the initial condition segment. The initial condition segment has two basic interfaces. The standard interface is a simple version providing a faster and laid-back approach to inserting most of the initialization values. The second type of interface is the advanced interface which contains three basic tabs detailing all the important initialization parameters to complement all relevant abilities offered through IMEX. An interface may be automatically selected after the entry of all initialization parameters, although the advanced interface is always available in the other interface.

4.2.1 Tree-View properties

To access tree view properties, right click the initial condition segment tab to drop the entailed menu consisting of validate, display and expand/collapse command. The validate command lists all the caution and error notice. The display command shows how the initial condition data has been saved in IMEX. The expand/collapse ribbon opens or conceals various items in the tree relating to the interface it is used in. A standard Interface can be generated after a new information data is uploaded or when the subsequent conditions stated below is satisfied:

i. That one PVT region is stated or must be defined
ii. An assigned constant for the bubble point pressure is defined by the grid.
iii. The given saturation value allocated to that grid for any capillary rise method for determining equilibrium is the median dived by the volume of saturation in that grid.
iv. That the stasis pressure defined in the reservoir is selected as the option for datum depth pressure.

When defining the bubble point there are control buttons which offer alternative processes to define the constants, and they can be recorded in the array selection region under the reservoir tree view tab. The dew point pressure, oil capacity, datum depth and reference depth can be entered using the advanced interface tab. The advanced model interface tab creates an entry for all the initialization values by clicking the block center menu. The use of more than one initialization section, dew point pressure and oil capacity fraction are also available in the initialization for the advanced interface. The main sub-regions under the advanced interface are the advanced properties, PVT properties and the calculation method properties.

4.3 PVT properties region

This is where most of the initialization parameters for various PVT regions are located. The PVT property region consists of reference pressure, contact depths for all the phases, reference depth, dominant water saturation (S_w) and datum depth information are located. In order to check each parameter associated with various regions, the particular region of interest will be selected from the initialization parameter for PVT. The entered information for PVT initialization may vary depending on the fluid model selected previously and the regions under it. PVT property region can be removed or updated as desired at any point of the initialization process. It can also be copied from one region to any region currently selected by entering the copy from region tab displayed at the left corner. The fluid model determines the range of properties that will be available during initialization and may need changes along the way. The methodology followed when entering the available properties can be completed either by use of tabular functions or using the array set up icon from the top by selecting the relevant property. The array set up will only refresh the correlative property described in the PVT property region if it is a constant.

In the absence of any correlative property for any region then the bubble point, dew point pressure and oil capacity cannot be properly refreshed automatically. In case of difficulties when defining the properties in the array set-up, the properties can be evaluated using the tree view property section by clicking the plus calculate tab. In the advanced parameter tab, some of the options which is not commonly found in other properties like the remaining oil saturation can be found.

4.4 Applications of CMG's IMEX

CMG's IMEX can be used in the following scenarios:

1. Unconventional gas & Liquids reservoir
2. Coal Bed Methane (CBM) and shale gas reservoirs
3. Infill drilling optimization
    - Horizontal & multi-lateral well placement
    - Oil and gas coning studies
4. Under-saturated/saturated oil reservoirs
5. Gas condensate reservoirs
6. Gas deliverability forecast
    - Reservoir/surface facility optimization
    - Naturally or hydraulically fractured reservoirs
7. Naturally fractured reservoirs
8. Gas-oil gravity drainage
9. Secondary recovery
    - Waterflooding

- Surface facilities modelling
- Polymer injection

10. Dry gas injection and pseudo-miscible solvent injection
    - WAG processes
    - Gas storage fields
    - Cycle optimization

4.5 Benefits of CMG

i. The use of CMG helps to complete simulation works quickly and is basically considered to be more reliable than other simulation tools.
ii. CMG provides detailed results on the different recovery methods.
iii. Can work diligently when compared with C-MOST for fast, reliable history matching, reservoir prediction in considerably shorter time.
iv. Smooth conversion from IMEX modelling to GEM and STARS simulators for tertiary recovery techniques.
v. CMG can be used for gas modelling in shale formations using IMEX.
vi. In fractured reservoirs, CMG provides a detailed modelling of matrix-fracture.
vii. CMG can be reliably used for non-Darcy fluid flow regimes.

4.6 Validity of Simulation Results

The authenticity of a reservoir simulation is important as it affects other external considerations. When results obtained create doubts or errors, it may be from unclarified guesses made or achieved by processes not acceptable by the model used in differential, spatial or time truncation errors. It may also be as a result of incomplete data report on the fluid and rock properties of the reservoirs. There could also be some errors due to approximation leading to an inexact solution of the difference equation, without taking into consideration the actual word count of the computer tool. Errors gotten due to approximation are generally considered small when they are compared to other types of errors. History matching information on the reservoir can be reviewed in cases where data quality is a problem or approximation errors are noted. When a simulated model result is still uncertain, evaluations done between the lab experiments and the simulated results can be used to check or compare the model's validity. This is done especially when the source of error is from data quality due to fluid and rock property or from inputs made from unclarified guesses. The comparisons done between the laboratory experiments and the simulated results are especially useful in quality model works in water or oil coning systems; gas or oil wells; and imbibition process in a fracture-matrix system.

4.7 Model Assumption

In most Black Oil Simulation models, one common assumption made is the solution of already free gas in respect with the amount of gas dissolved in oil at any pressure i.e. saturated Rs (P) during a process referred to as re-pressurization. This assumption may be faulty in some instances with thicker grid block and differential gravity in the vertical section between oil and gas is present. The free gas which is re-dissolved may have existed in free form at the top of the layer, this challenges the model set up as it initially dispersed throughout the block. The isolated gas by gravity segregation in reality will saturate only the top portion of the remaining oil there (residual oil) where the gas is situated. Irrespective of how the re-pressurization process happens, the model just assumes an absolute re-solution in the whole blocks with oil. A temporal solution to this problem is by making a process known as "Pressure Hysteresis" where measurements are taken twice at one exact pressure but at different pressure frequency i.e. when the pressure is changing from high to low versus when it changes from a low pressure to that exact pressure.

Another assumption that was previously made was utilizing one Formation Volume Factor of oil in respect to pressure and also one solution Gas Oil Ratio curve (Rs/pressure) for reservoirs. In actuality, many black oil reservoirs have distinct values of oil gravity with depth as well as different PVT data by depth or vicinity. The different Formation Volume Factor by depth values can be described in the model simulator by letting the initial solution Gas Oil Ratio (R_{si}) to change with depth in the region where under-saturation is specified. This generates one separate Formation Volume Factor and Solution Gas Ratio curves in respect to pressure. However, in some instances where different groups of curves with more than one oil component are required, using just oil as its only mechanism for the Black Oil model can cause significant error.

It was found that some basic reservoir techniques that are considered important like: capillary pressure hysteresis, rock compaction and non-wetting relative permeability (Kr) may not have great impact during the modelling of the well. Interestingly, a well drilled for producing and then completed may show production from a considerate amount of the layers while the remaining layers may be used for injecting water or other fluids by re-cycling. This problem with the layers can be due to bad vertical transmission amongst all the layers or increased productivity index with a reduced rate (small pressure differential) in the well. An intense treatment can be done to solve this issue of layers by modelling the wells liquid power and phase isolation as well as provision of accurate oil-gas mixtures for the different layers experiencing injection.

4.8 Result and Discussion

Using the IMEX black oil simulator the input design for one well named M-21 was produced after which the data-set was then validated and run.

The results simulated are as given in the Table 4.1 below:

Table 4.1: Calculated Results from CMG

Parameter (unit)	Results
Total Oil in Place (MMSTB)	~29
Total Water in Place (MMSTB)	~74
Total Gas in Place (MMSCF)	46013
Hydrocarbon Pore Volume (M RBBL)	36607
Total Pore Volume (M RBBL)	110763

The well data provided was used for completion and production began for a period of 2.5 years at changing oil production rates. The production time was set without any injection of water or solvent addition. Table 4.2 shows how the perforated interval will produce naturally in the reservoir.

Table 4.2: Well M-21 Production Result

Field Total	Oil (MSTB)	Gas (MMSCF)	Water (MSTB)
Cumulative Production	573.31	1325.3	251.05
Fluids Currently in Place	28325	46013	73767
Production Rates	0.10000	0.13456	0.5868
Injection Rates	N/A	0	0

Figure 4.1 shows how the oil rate reduced from 1000bbl/day to 578bbl/day on the 720th day before it is stabilized for 100stb/day again. Figure 4.2 and Figure 4.3 show the gas rate and gas oil ratio (GOR) over time, respectively. On the 900th day, it can also be seen in that the water-cut is about 37% as depicted in Figure 4.4. The results retrieved from the simulation are given below.

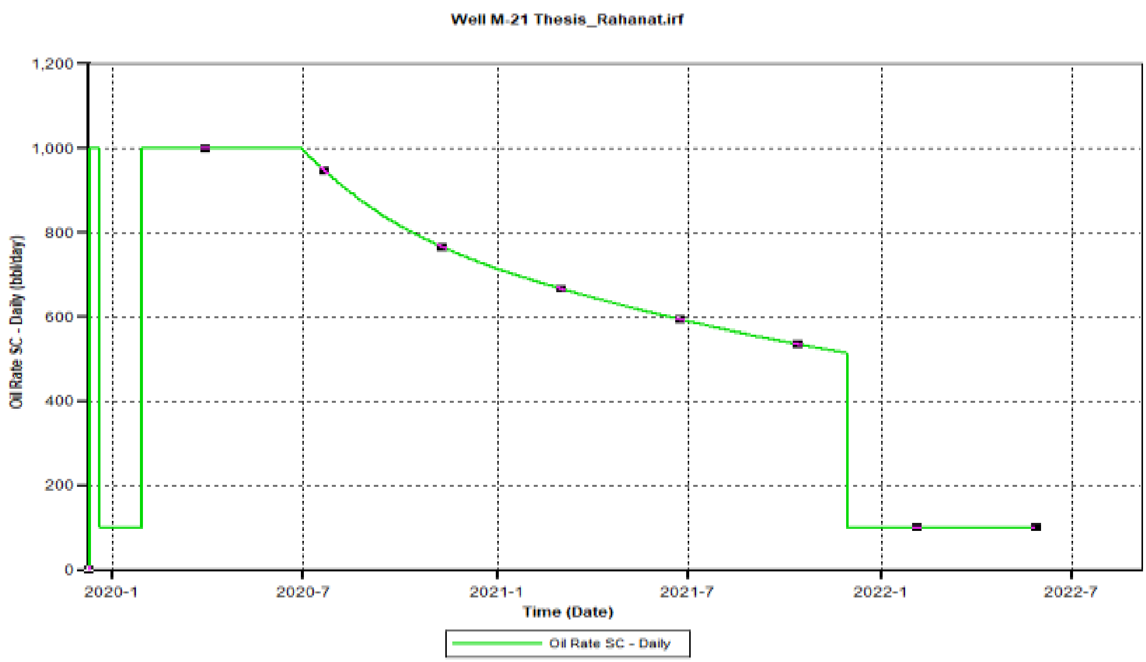

Figure 4.1: Oil Rate for M-21 by Time

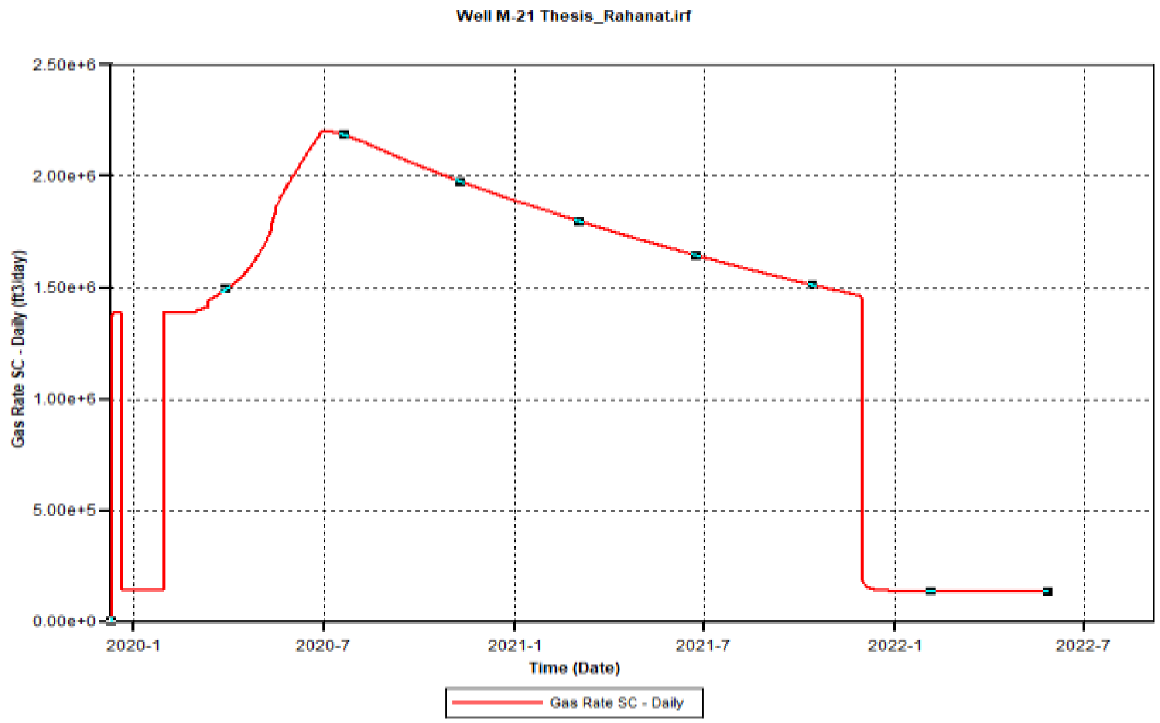

Figure 4.2: Gas Rate for M-21 by Time

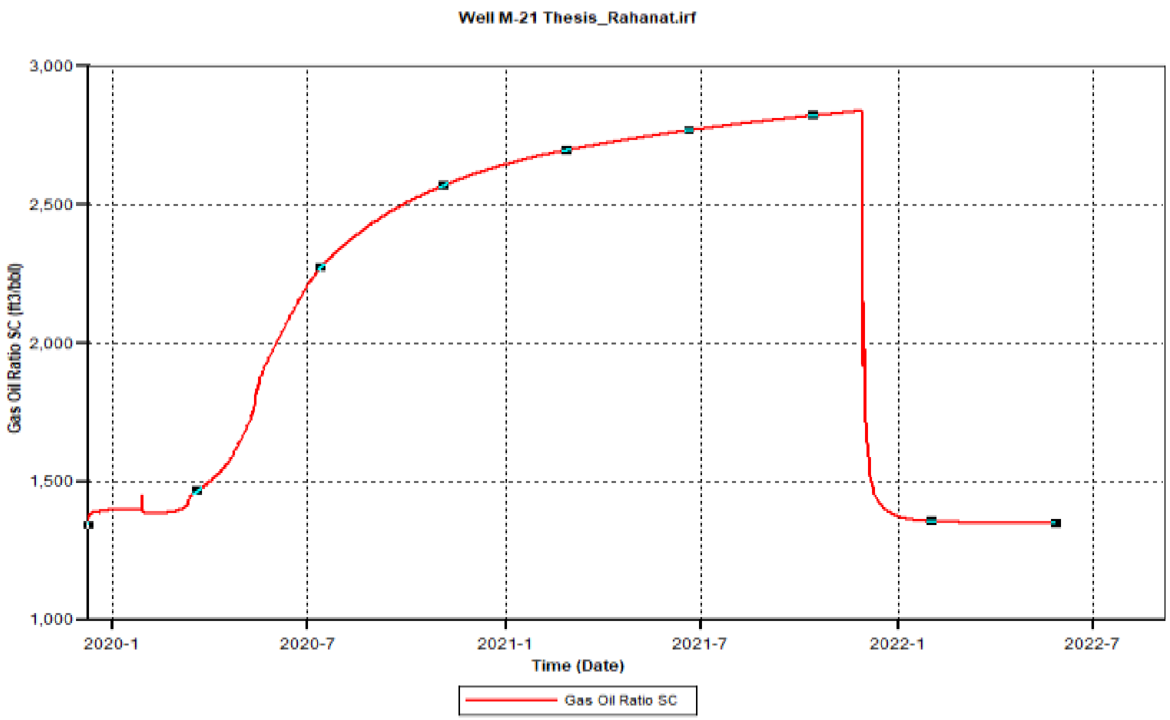

Figure 4.3: GOR for M-21 by Time

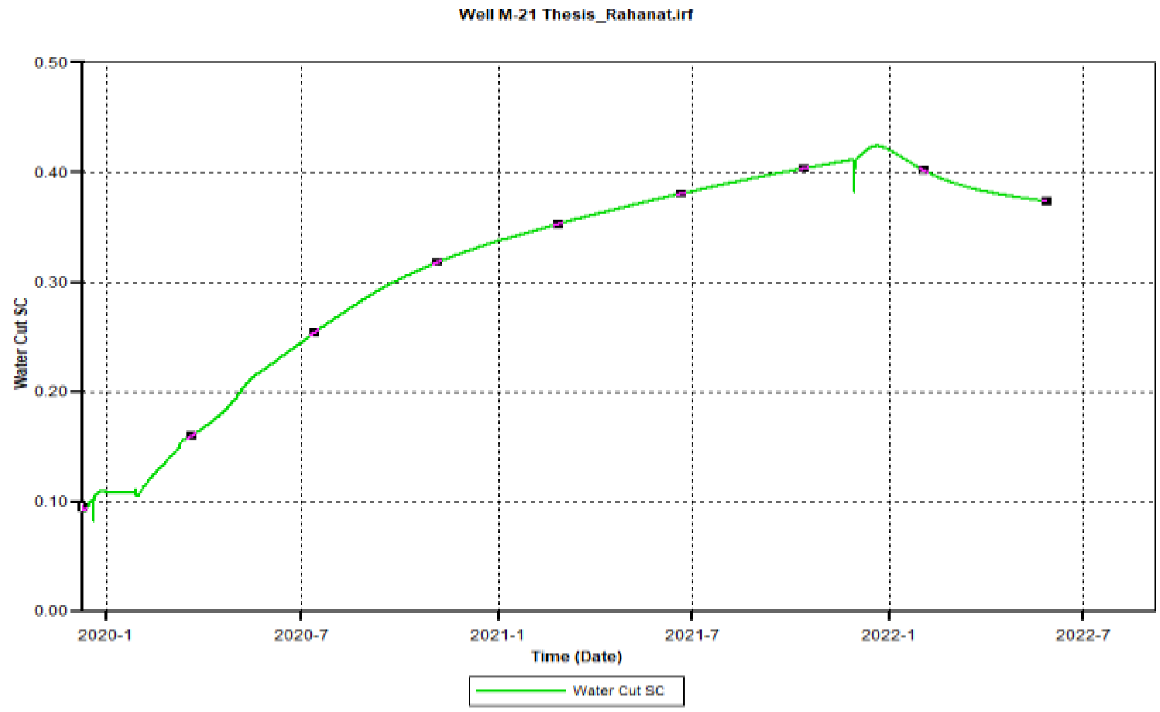

Figure 4.4: Water Cut for M-21 by Time

Figure 4.5 shows how the bottomhole pressure (BHP) changes over time, while Figure 4.6 shows how the gas oil ratio behaves with change in production rate.

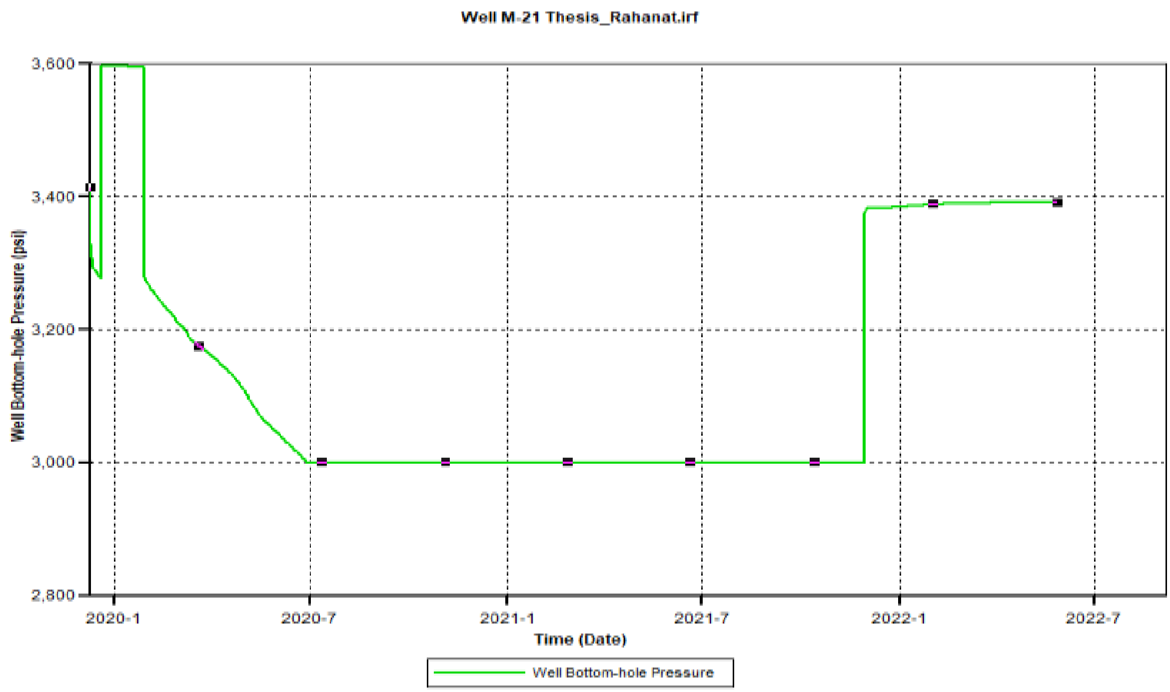

Figure 4.5: Well BHP by Time

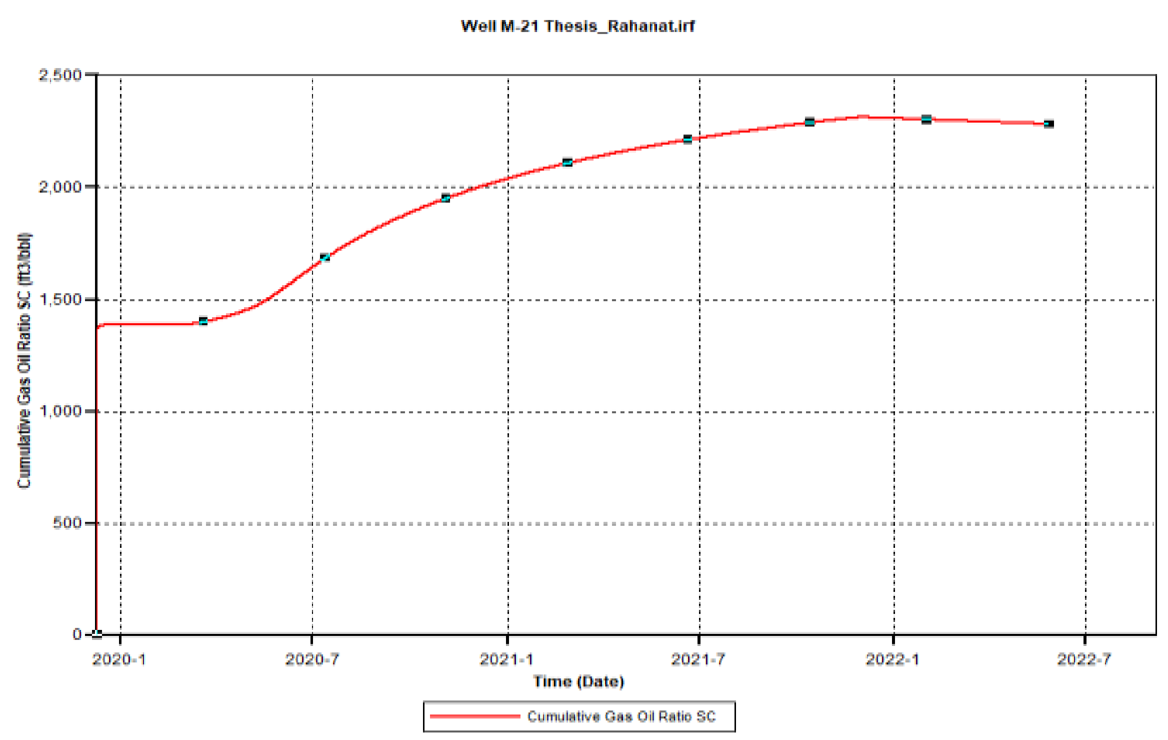

Figure 4.6: Cumulative GOR by Time

The Figure 4.7 below shows the comparisons between the recovery factor, production rate and gas oil ratio (GOR) with time.

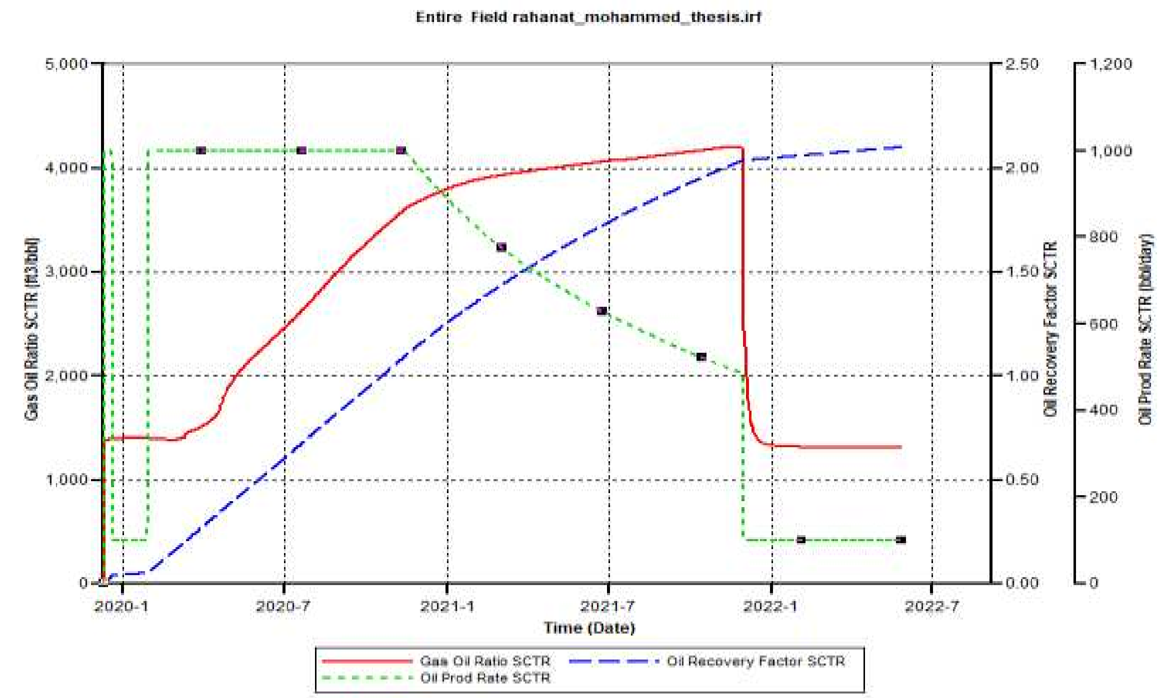

Figure 4.7: Recovery Factor, GOR and Production Rate by Time

A possible performance simulation was done by injection water at a rate of 5000 bbl/day into the reservoir at a maximum bottomhole pressure of 7000 psi through an injection well. The water injection is done to provide pressure support to a level close to its initial reservoir pressure. Table 4.3 shows the results of the waterflooding scenario.

Table 4.3: Waterflooding Results

Field Total by Waterflood	Oil (MSTB)	Gas (MMSCF)	Water (MSTB)
Cumulative Production	702.00	1762.7	513.21
Cumulative Injection	N/A	0	4500.4
Cumulative Water Influx	N/A	N/A	0
Production Rates	0.10000	0.16438	0.18496
Fluids Currently in Place	28196	45574	78005
Injection Rates	N/A	0	5.0114

At the end of the simulation run, the results show a considerable increase in the oil rate GOR and water cut. The graph plots showing cumulative production after water injection from one well is provided in subsequent pages where Figure 4.8 shows the effects on gas oil ratio (GOR) by time. In Figure 4.9, Figure 4.10 and Figure 4.11 shown below, it can be seen how waterflooding affects the oil rate performance, water cut and oil saturation, respectively.

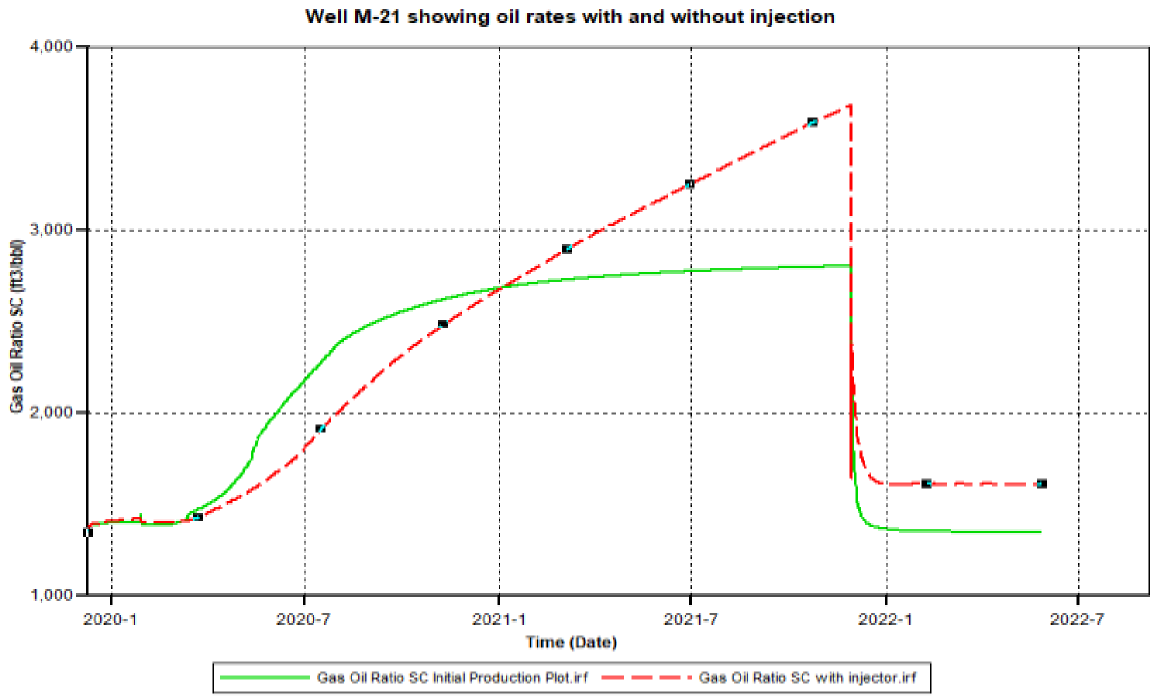

Figure 4.8: Waterflooding Effect on GOR

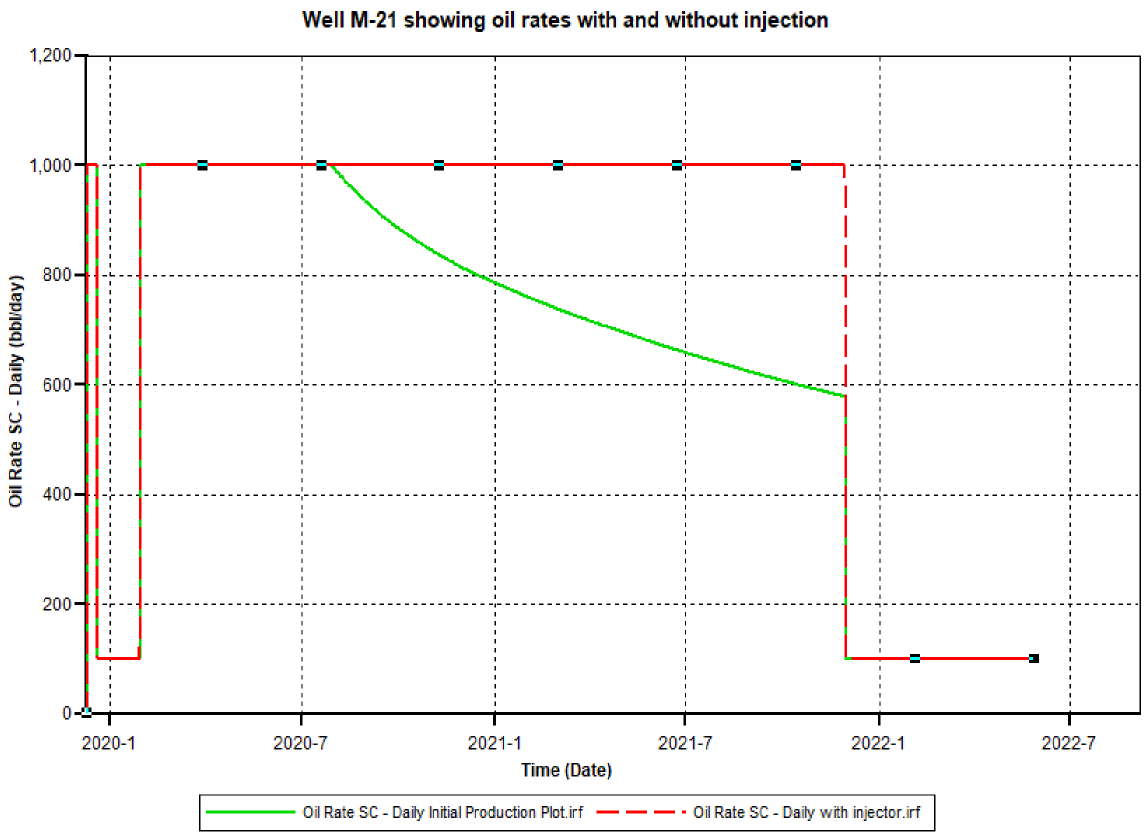

Figure 4.9: Waterflooding Effect on Oil Rate

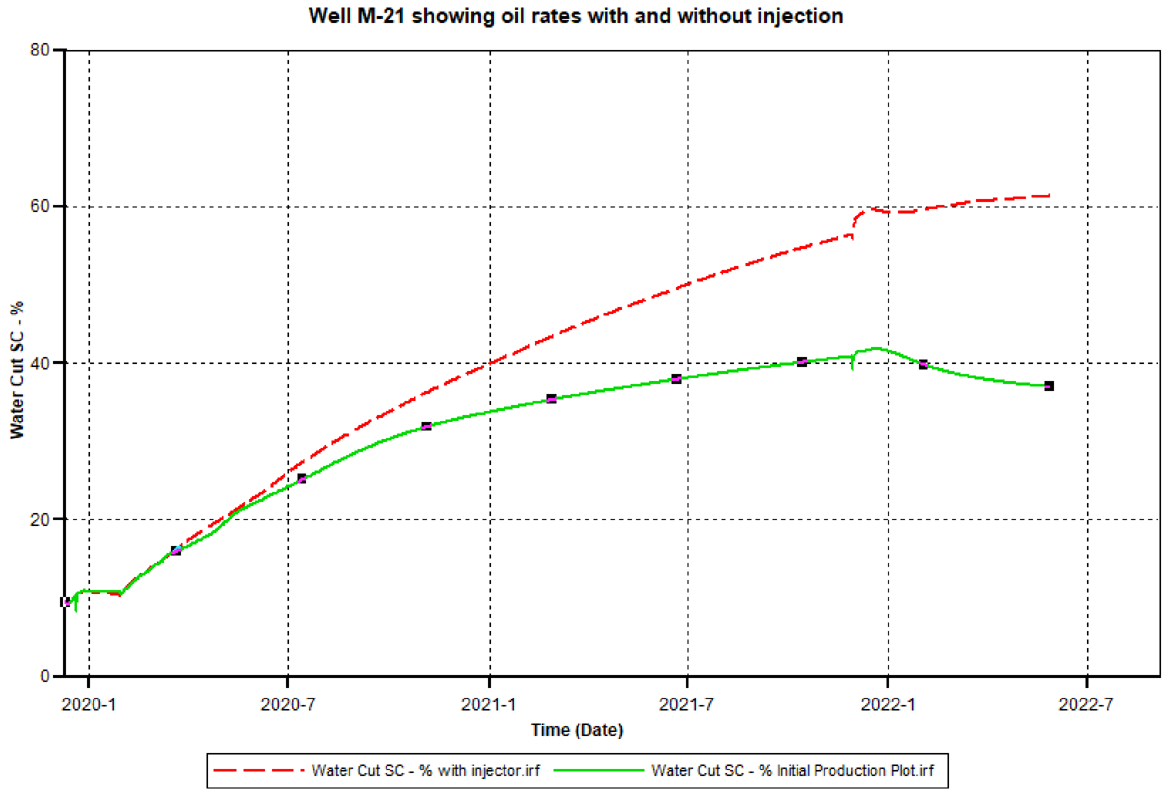

Figure 4.10: Effect on Water Cut with Injection

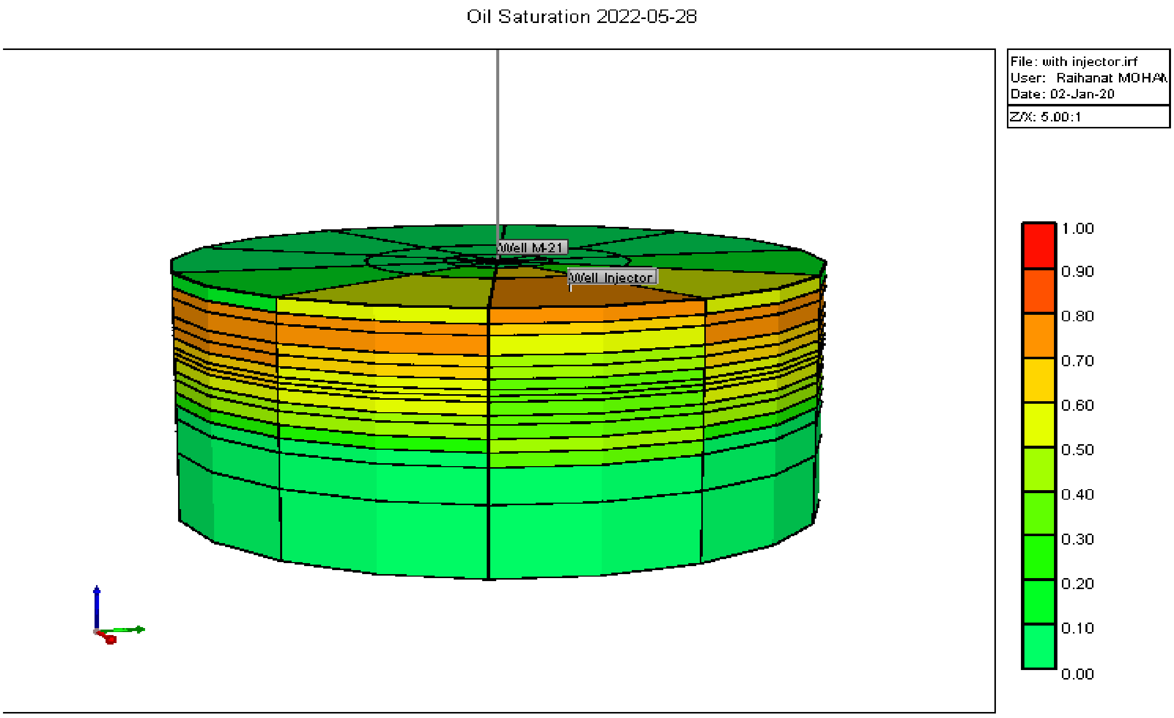

Figure 4.11: Oil Saturation after 900 days

The changes in bottomhole pressure (BHP) as a result of waterflooding can be seen in Figure 4.12.

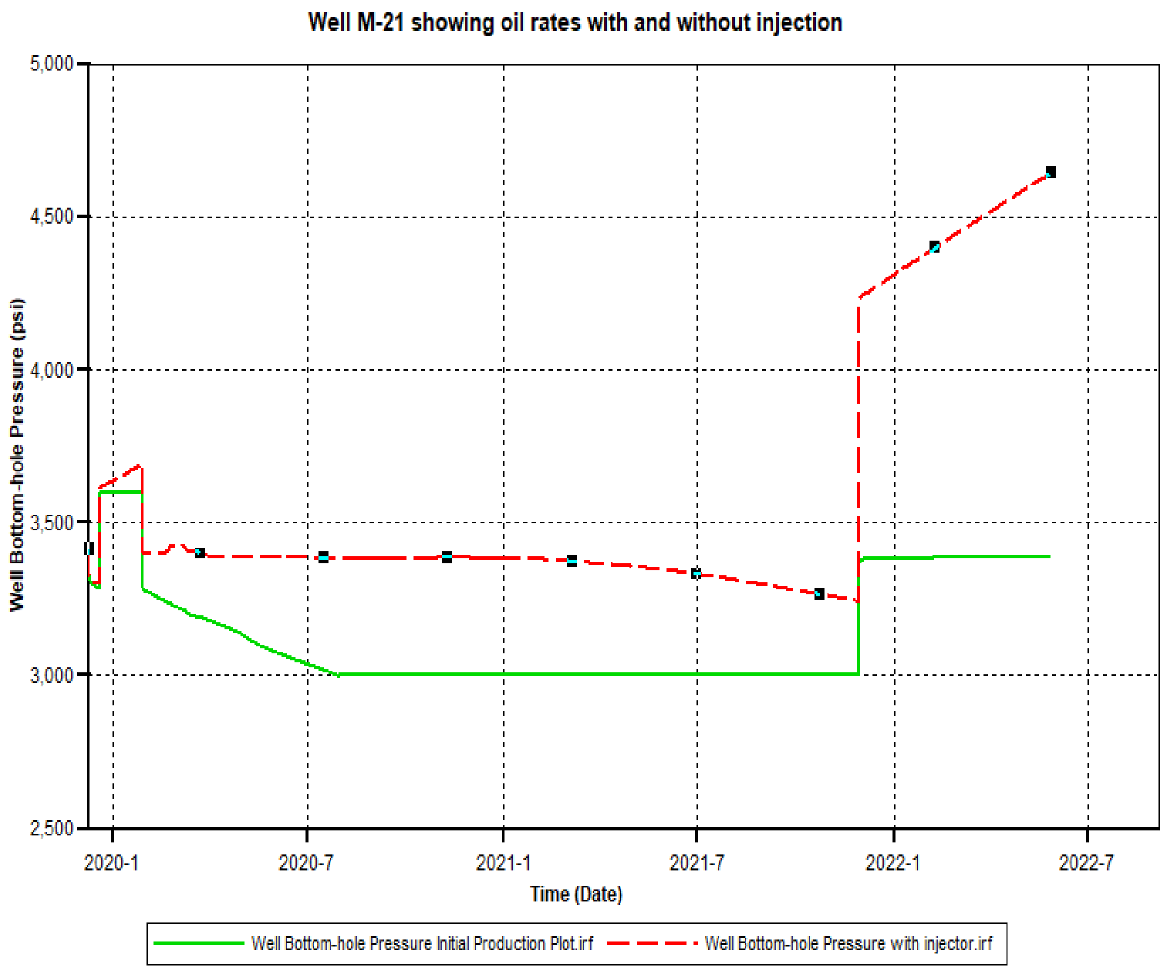

Figure 4.12: Injection Effect on BHP

Using the production profile given in the data sample section, an attempt to compare production performance by changing the interval of the well completion blocks. Four runs were made in perforation blocks (1,2) (1,5), (1,5) (1,7), (1,6) (1,8) and (1,7) (1,8). The results show that bottomhole pressure in the longest perforation block (1,2) (1,5) at the end of the production period has the lowest bottomhole pressure and water cut in percent. The center blocks for (1,5) (1,7) has the highest GOR as compared to the others in the plot. Figure 4.13 shows how the different perforation intervals affect oil rate over time, while the initial production interval has the highest water cut as seen in Figure 4.14 below. Lastly, the effect of perforation interval on GOR and BHP can be seen in Figure 4.15 and 4.16, respectively.

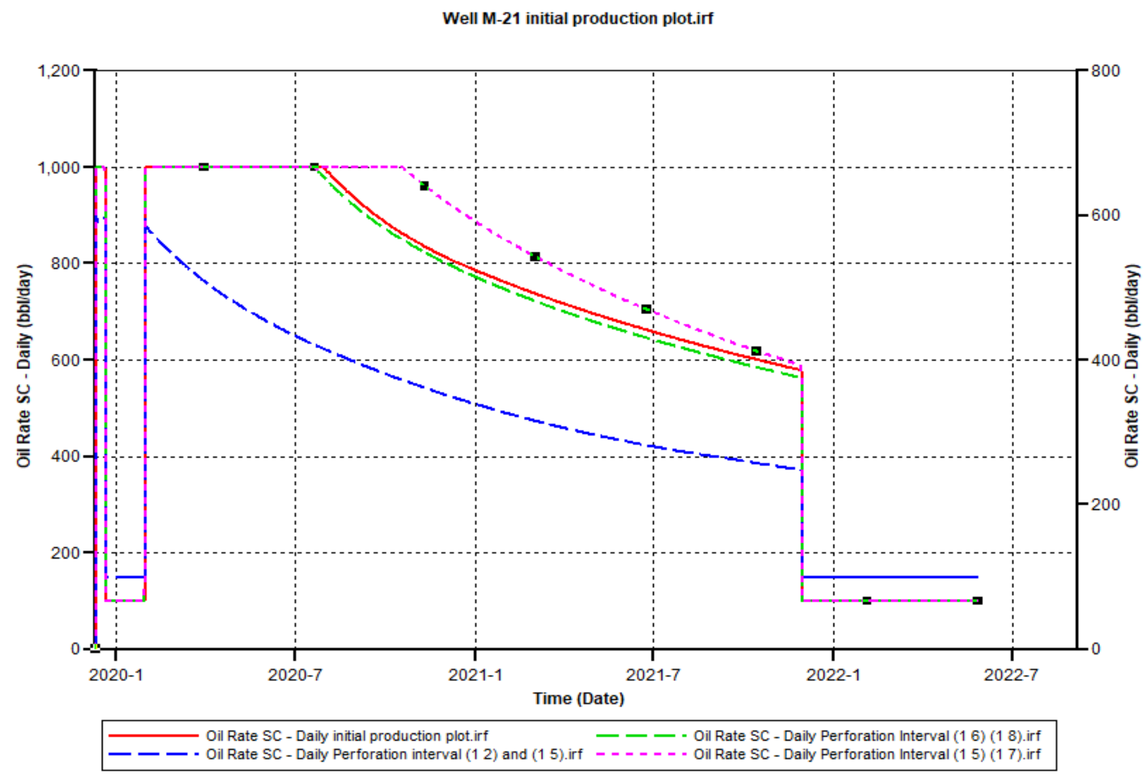

Figure 4.13: Perforation Interval Effect on the Oil Rate

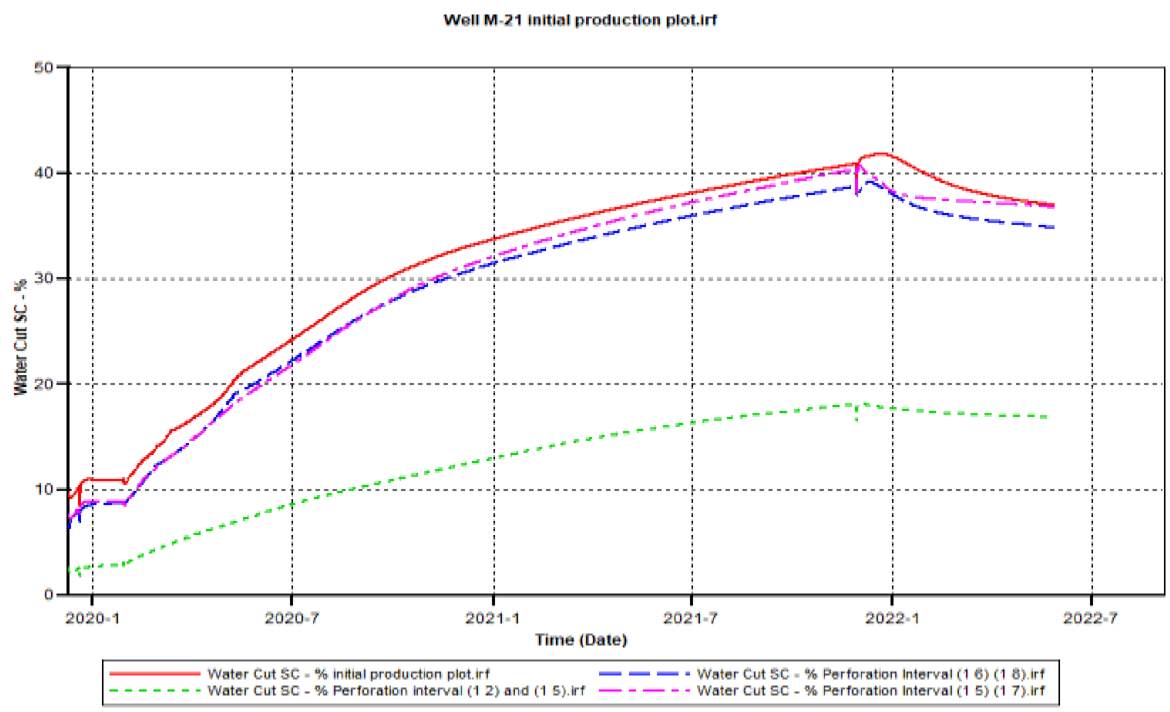

Figure 4.14: Perforation Interval Effect on Water Cut

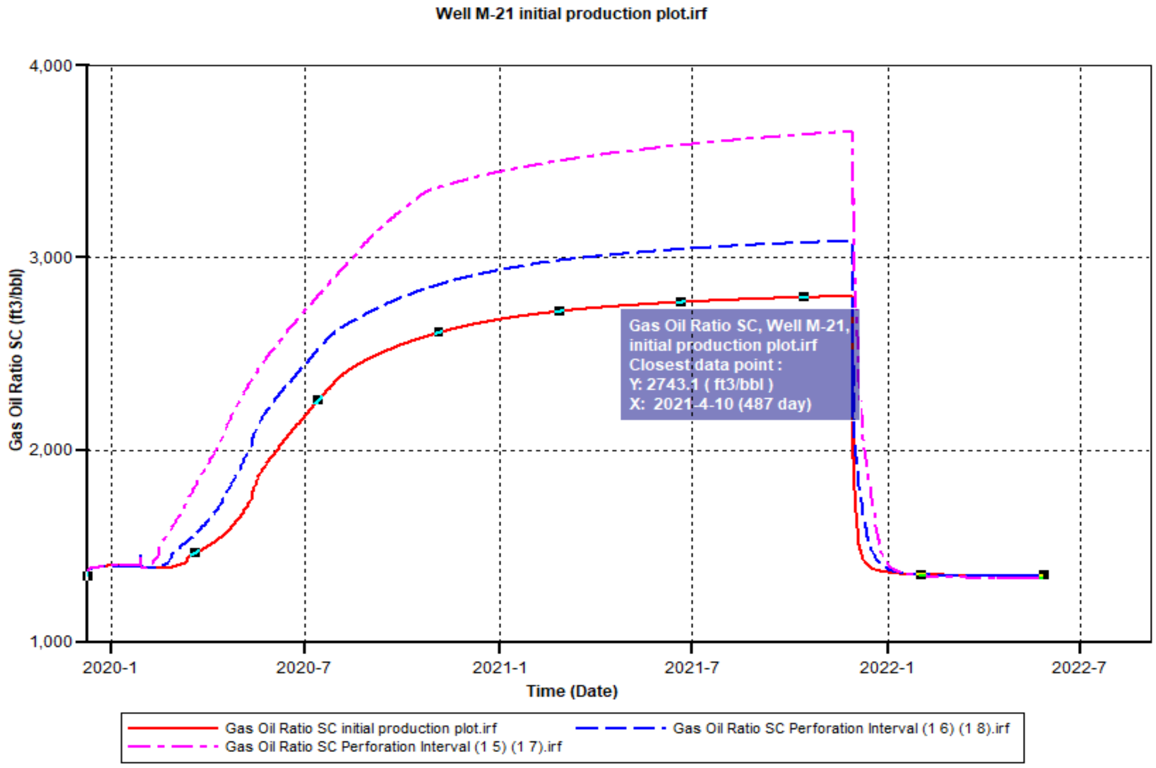

Figure 4.15: Effect of Perforation Interval on GOR

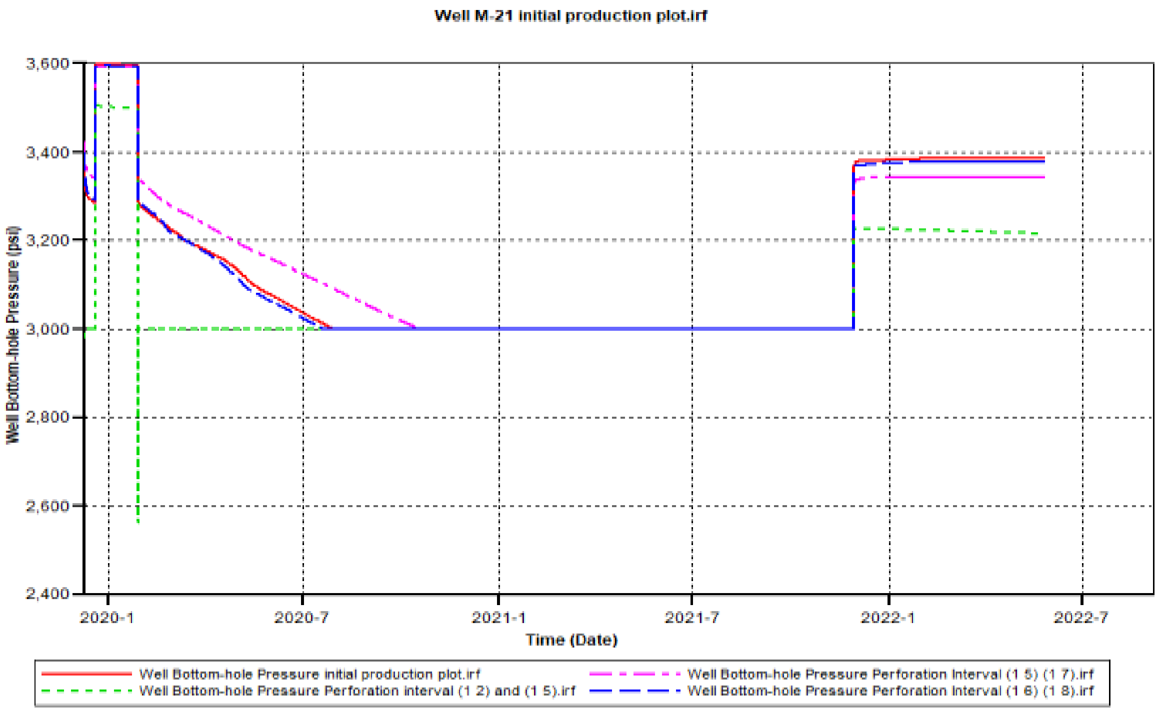

Figure 4.16: Effect of Perforation Interval on BHP

Results on a single plot showing how the simulated production rate performed over time is given in Figure 4.17 and Figure 4.18.

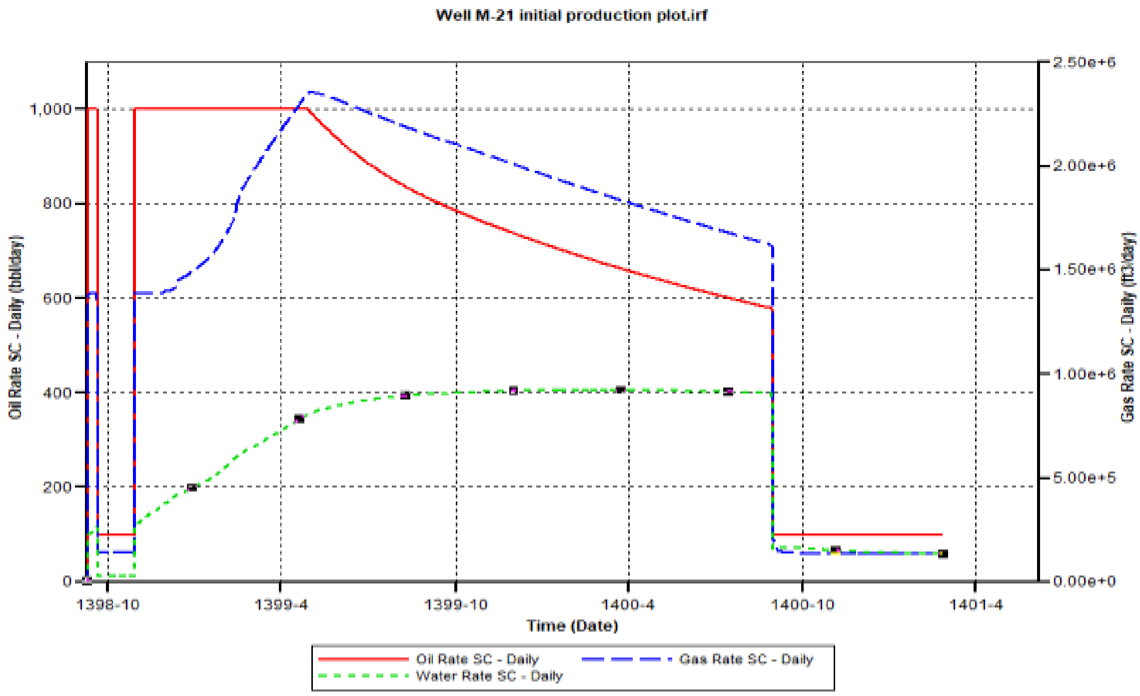

Figure 4.17: Gas, Water and Oil Rate by Time

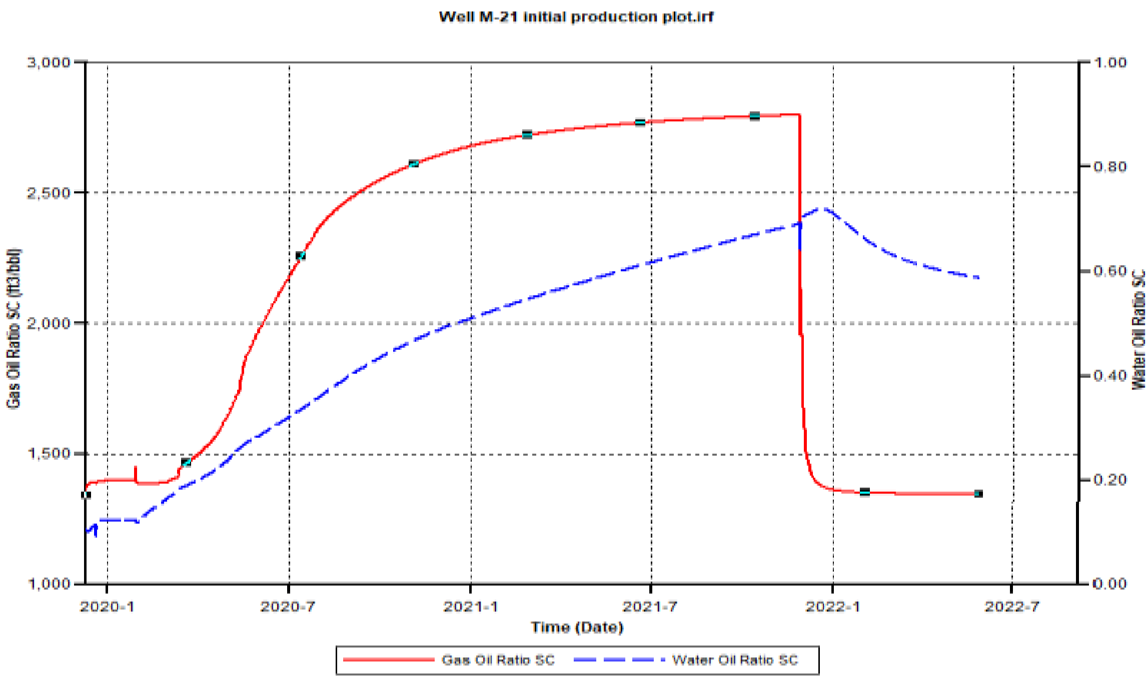

Figure 4.18: GOR and WOR against time

CHAPTER 5

WELL MODELLING

Well models are done to describe systematic volume of fluid flow into a well or from the well with considerations on the flowing wellbore pressure and pressure around the well itself (Aziz and Settari, 1979; Nolen, 1990; Peaceman, 1978). A good reservoir simulation model assumes the well to be a source/sink in a way that describes the whole boundary situation of the well and the fluid flow around it. A typical model is designed to handle one lateral well (horizontal, slanted or vertical). In some cases, prolonged well models are able to control friction losses by the use of less complicated solution for friction loss (Schlumberger, 2005).

Some of the important parameters which provide information on a typical well modelling process are the:

- Mathematical expressions used
- Density treatments though iterative solutions (subject to wellbore pressure & phases fractions)

It is imperative to note that the typical well modelling only studies the hydrostatic pressure variations in the wellbore which is not very promising. Other limitations of these models is that the appropriate density treatment procedure (using one or more iterations) and usually, transient effects in the well may be unaccounted for.

The second well type is the multi-segment well model relatively used in describing flow patterns in wellbore (Schlumberger, 2005; Holmes, 1998). It can be used in horizontal well with high rates. Such wells often have a higher friction factor associated with them (Ouyang, 1998). Since friction and acceleration are two important parameters in long-horizontal with greater volumes in the wellbore, this well model provides detailed information on decline in pressure caused by friction. Also, some lateral well with large phase hold-ups in their flow pattern can be modeled with this type of well. Some of the most important parameters which provide information on the multi-segment well modelling are the geometry and variables associated with the length. A well performance model is one designed to assess a wells design, and evaluate possible alternatives to the completion model and then forecast the performance of the well in the near future depending on its varying reservoir characteristics.

5.1 Well Modelling with PROSPER

PROSPER is a computer software for simulation and modelling both wells and pipelines, it was commercialized in the 90's and due to its development rate from the past two decades it has been the subject of ongoing research. Every year that passes by, new functions and models are added to the previously extensive list of options in the PROSPER program.

There are more than three (3) million groups of options which can be used to describe a gigantic majority of the physical phenomena occurring in the wells and pipelines. Despite the large number of parameters which can be modelled, the PROSPER adaptive interface only presents the operator with a useful input fields and set of choices according to the options chosen in the menu, maintaining the model building effort at a minimum (Figure 5.1)

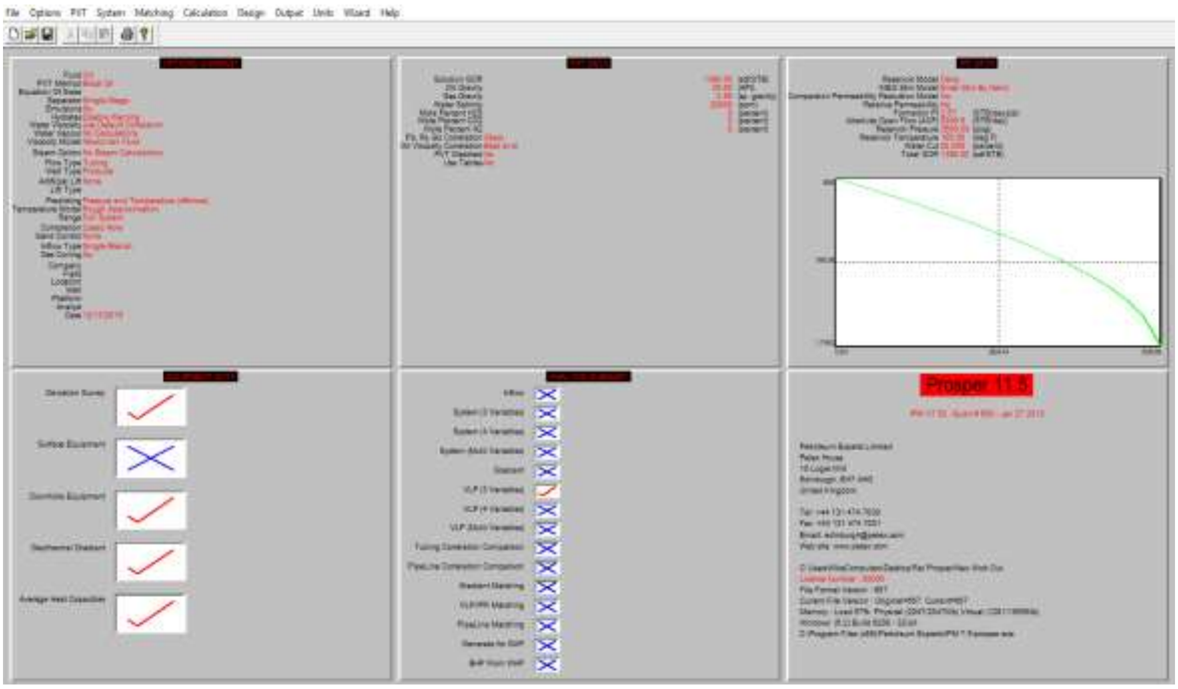

Figure 5.1: PROSPER work sheet

PROSPER has advanced into the standard for industry well and pipeline modelling due to its unique modelling capabilities and unmatched sound technical basis. The program recently forms one of the basis stones of the Digital Oil Field system (DOFs), and the calculation engine is developed by several workflows in real time in hundreds of fields worldwide.

5.1.1 Fluid PVT modelling with PROSPER

PROSPER was used to model the reservoir fluid. This is done by matching the PVT data obtained from laboratory analysis to the available correlations. The match is performed through nonlinear regression, adjusting the correlations to best fit laboratory measured PVT data. It applies a multiplier (parameter 1) and a shift (parameter 2) to each of the correlations. The correlation that best matched the fluid is the one which required the least correction to match. The standard deviation represents the overall closeness of the fit, which is usually the lower value.

5.1.2 Data input (equipment)

Data input for the equipment is made up of several input data such as geothermal gradient data, bottomhole equipment data, deviation inspection data and input variables regarding the heat capabilities.

1. ***Geothermal Gradient (Gg) Data:*** Geothermal gradient is a concept used in describing the rate of change in temperature with depth. At deep depths, temperature increases with depth due to factors such as the earth core, friction, radioactive effects, chemical reactions as well as the presence of magma. A geothermal gradient data will show temperature values against depth of the well.

2. ***Bottomhole Equipment Data:*** Shows information of tools and drill strings on the fittings used and its size. Information on the equipment like the tubing string which aids movement of reservoir from down formation to the very surface of the Christmas tree. Figure 5.2 shows the well schematic developed by PROSPER from the inputted values.

3. ***Deviation Inspection Data:*** Shows data on the Measured Depth (MD) and True Vertical Depth (TVD). When these variables are imputed into PROSPER the wells angle and total displacement in the well can be calculated.

4. ***Heat Capacity:*** Average heat capacities can be retrieved from PROSPER as specified. The effect of surface equipment on the performance of the wellbore was not put into consideration and thus, surface data equipment was ignored.

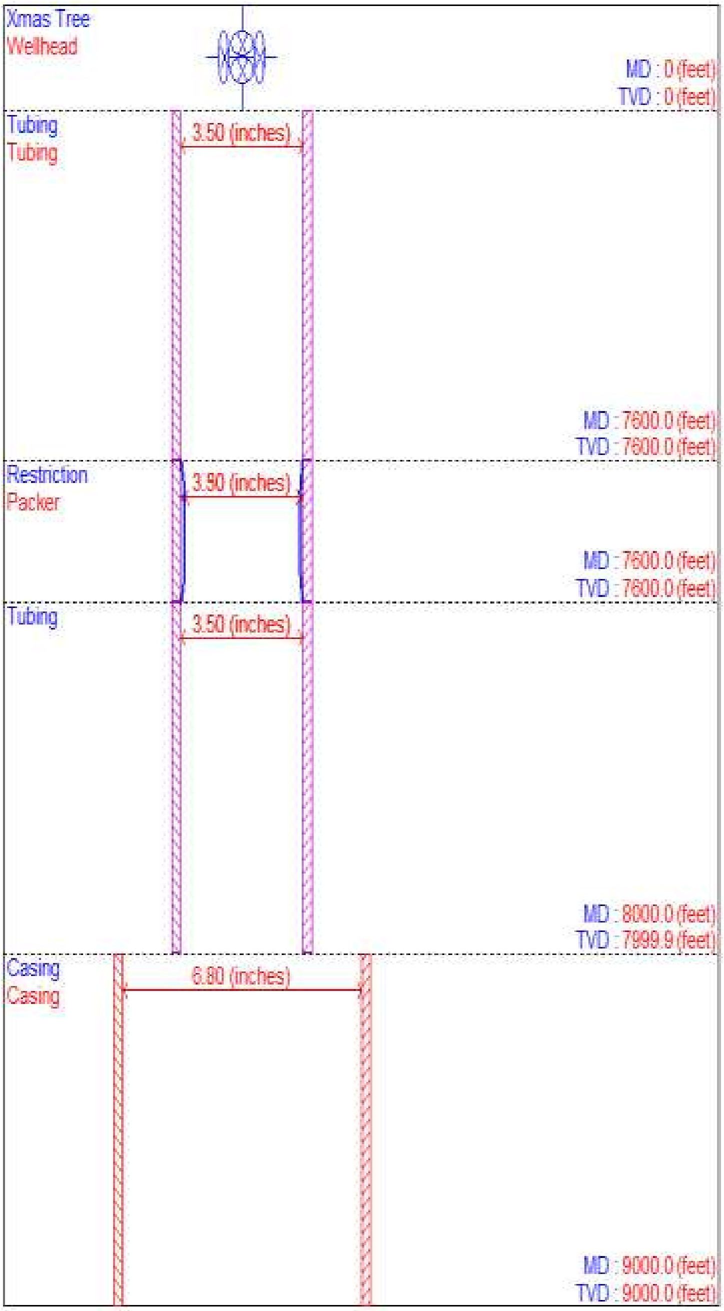

Figure 5.2: Schematic representation of the well completion designs.

5.1.3 Inflow performance relationship (IPR) model

In PROSPER, detailed set of inflow models which complements the flow efficiency in a multi-phase system is used in calculation for Nodal Analysis to be done in any type of well. Over the years, more than 20 inflow models have been established for applications in diverse geometries. Applicable geometries may be horizontal, deviated, vertical or multilateral. In addition, recent development has introduced exemplary designs for inflow models which better explains the varying PVT conditions in the well drainage areas and other zones. The new developments create an avenue for successful study on re-perforation to be considered, wellbore skin analysis, sand control possibilities as well as other sensitivity studies to be done.

5.1.4 Initiating inflow performance relationship (IPR) for the well

In order to initiate the inflow performance relationship curve of the well, PROSPER will be used to select the model for the reservoir using Darcy's equation. After the IPR is gotten, an outflow performance curve is then generated and used in finding the production rate at their point of intersection. The outflow performance curve (tubing curve) describes flowrate as a function of BHP (Figure 5.3) and can depend on various factors such as: tubing size, surface pressure, gas-oil ratio (GOR), water cut, pressure-volume-temperature information (PVT) and well depth

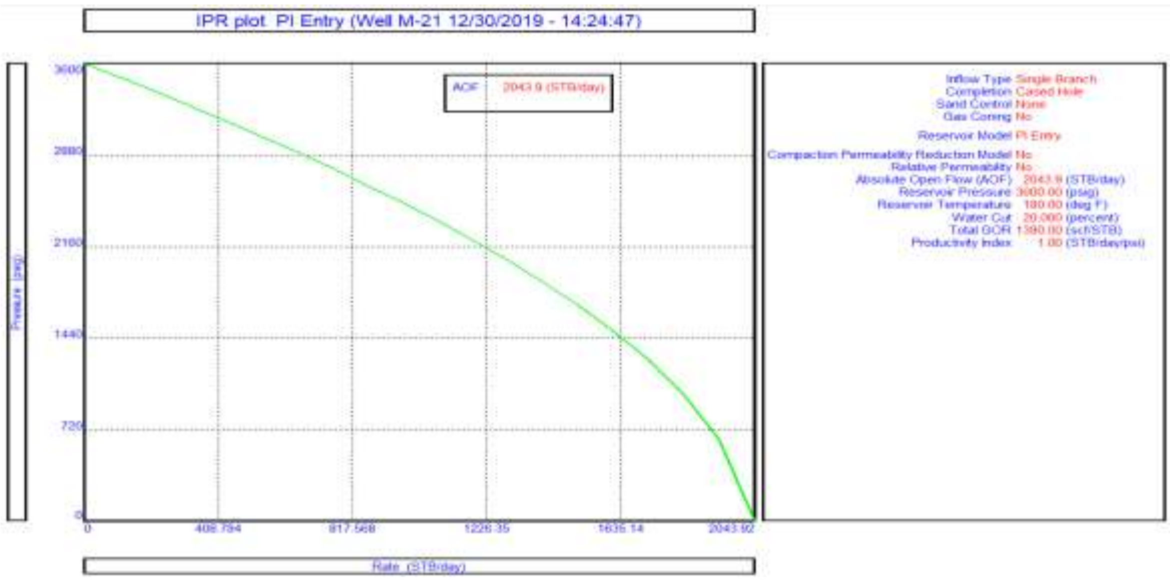

Figure 5.3: Prosper IPR plot - A typical inflow performance relationship curve (IPR)

5.1.5 Outflow Performance (VLP) Model

Through research, it was found that the introduction of PETEX with all its distinct features in the PROSPER package has led to the formation of some branded multi-phase pressure drop models. The models were created to provide the system with a working model that is much more reliable than the older models existing in the industry. The multi-phase pressure drop models may be empirical or mechanistic with design completed to overcome the restrictions of the previous models around. PETEX is enhanced with varieties of data set with different pressure drop measurements that have been introduced to give room for comparison between the new physical model to the actual information present.

Professionals in the industry have carried out separate correlations which proved that in fact the pressure drop model is reliable and dependable for ascertaining the validity of measurements gotten from the field. Users can analyze and match results obtained from the multi-phase pressure drop models with the one obtained in PROSPER to ascertain the fitting or its dependability throughout the life of the well. A typical outflow curve is shown in Figure 5.4.

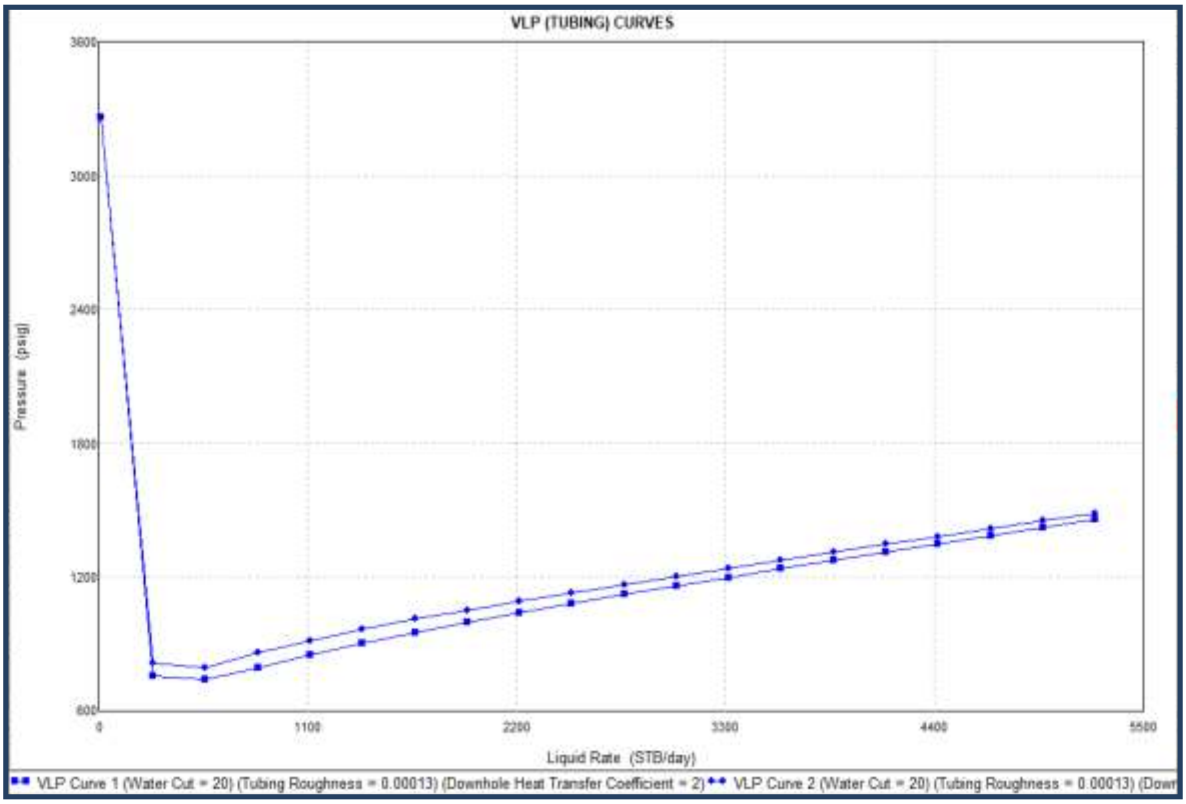

Figure 5.4: Outflow performance (VLP) model curve

5.1.6 Making correlations to match measured reservoir pressures

At this point, the multiphase flow relationships are then modified by correlating it to fit with the measured bottomhole pressures and the flowrate gotten from the production test. A matched OPR makes it possible to match the flowrate and down-hole pressure to the inflow performance curve (IPR). This match is successfully done by attaining a non-linear reversion. The difference within the calculated and measured pressures is then found by correlation.

From the equation for pressure loss, gravity and friction factors are adjusted until the measure values and calculated ones are around 1 psi each or completed before 50 iterations. The gravity and friction factor have multipliers that must stay within 10 percent, denoted by constant 1 and 2 respectively (Petroleum Experts, 2010). The report from the Outflow Performance Model (VLP) that best matched the Modified Duns and Ross correlation is given in Figure 5.5.

Tubing Correlation Parameters

File : C:\Bugs\Samples\prosper\VLP Match.Out

Report Date : 02/26/07 17:27:19

Fluid : Oil

PVT Method : Black Oil

Well : Oil Example

Analyst :

Correlation	Parameter 1	Parameter 2	Std. Dev
Duns and Ros Modified	1.00	1.00	
Hagedorn Brown	1.01	1.23	0.87185
Fancher Brown	1.00	1.00	0
Mukerjee Brill	1.00	1.00	0
Beggs and Brill	1.00	1.00	0
Petroleum Experts	1.00	1.04	0.057646
Orkiszewski	1.00	1.00	0
Petroleum Experts 2	1.00	0.98085	0.07988
Duns and Ros Original	1.00	1.00	0
Petroleum Experts 3	1.00	1.00	
GRE (modified by PE)	1.00	1.00	
Petroleum Experts 4	1.00	1.00	
Hydro-3P	1.00	1.00	
OLGAS 2P	1.00	1.00	
OLGAS 3P	1.00	1.00	
OLGAS3P EXT	1.00	1.00	

Figure 5.5: Tubing correlation parameters (Petroleum Experts, 2010).

5.1.7 Performance curve and sensitivity analysis for the well

With the availability of flowrate and wellhead pressure at different reservoir pressure (P_r), the performance curve can be generated. The generated graph shows the pressure at the wellhead at various points and the pressure at which the well will most likely not flow and where is more viable for production flowrate. With more production from this well, the reservoir pressure will likely fall from the initial pressure recorded. This well performance curve was generated using five various reservoir pressures between 2800 psig and 3000 psig. After the generation of well performance curve, sensitivity analysis is then conducted to make comparisons on the outcome of different tubing size on the well. Large tubing is expected to lift higher liquid rate as compared to a smaller tubing size. The diameter also contributes to the capability of the tubing for production purposes in the well (Lea et al., 2008).

5.2 Results and Discussion

The Figures below shows that with the reservoir pressure below 3600 psig at the current producing condition i.e. without lift, tubing diameter of 3.10 inches, tubing head pressure (THP) of 600 psig and a water cut of 20 %, the reservoir fluids will flow to the surface. To conclude on, when the reservoir pressure declines there will be a decline in the performance of the well. The results generated are given in Figures 5.6 to 5.9.

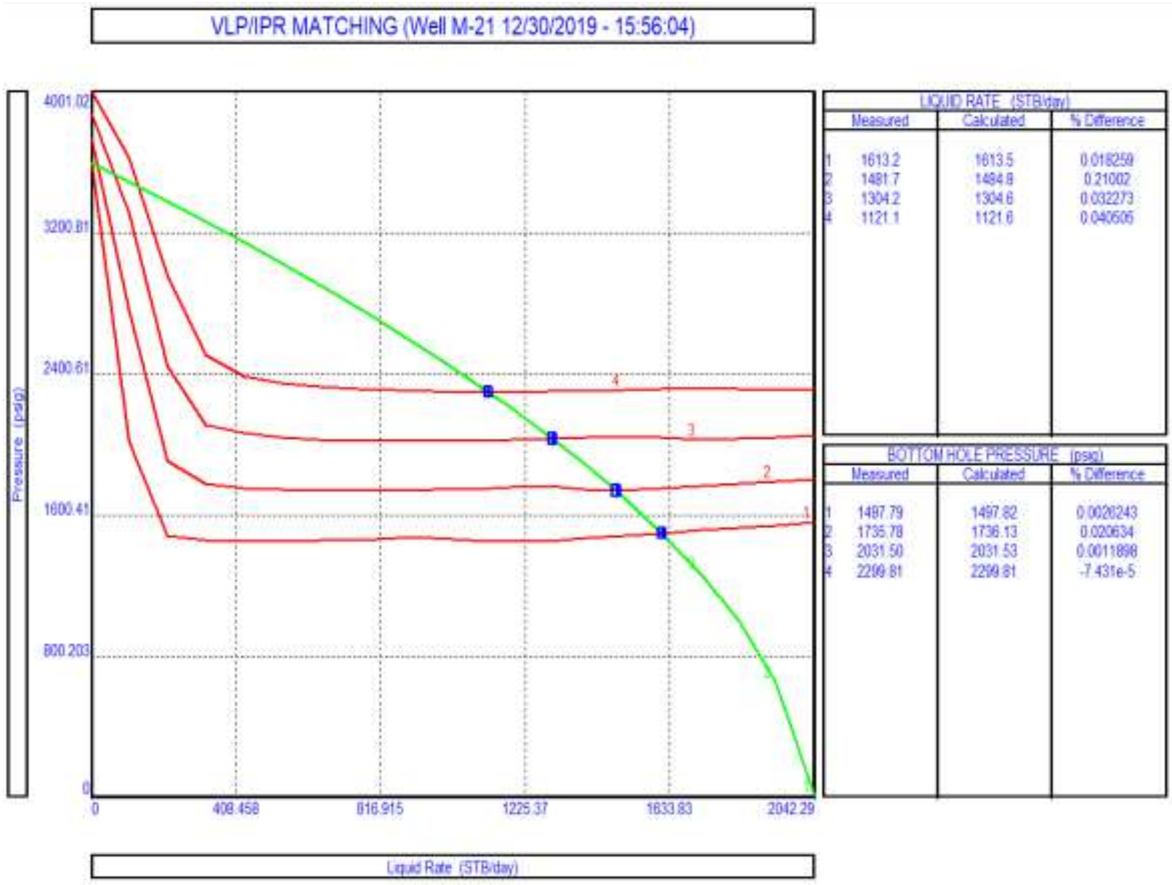

Figure 5.6: The Effect of THP on VLP and IPR

5.2.1 The effects of tubing head pressure (THP)

When the wells tubing head pressure lowers to about 400 psig or more and the reservoir pressure is under 3600 psig, the well will be able to carry liquids to the surface. Similarly, when the tubing head pressure increases above 1100psig, the well would not be capable of lifting fluids to the top for a long period of time even with a reservoir pressure of 4000 psig. The image in Figure 5.6 shows how the tubing head pressure of the well affects fluid rate. From the image; it can be concluded that when the tubing head pressure reduces, there is an increase in flow rate and consecutively an improved well performance.

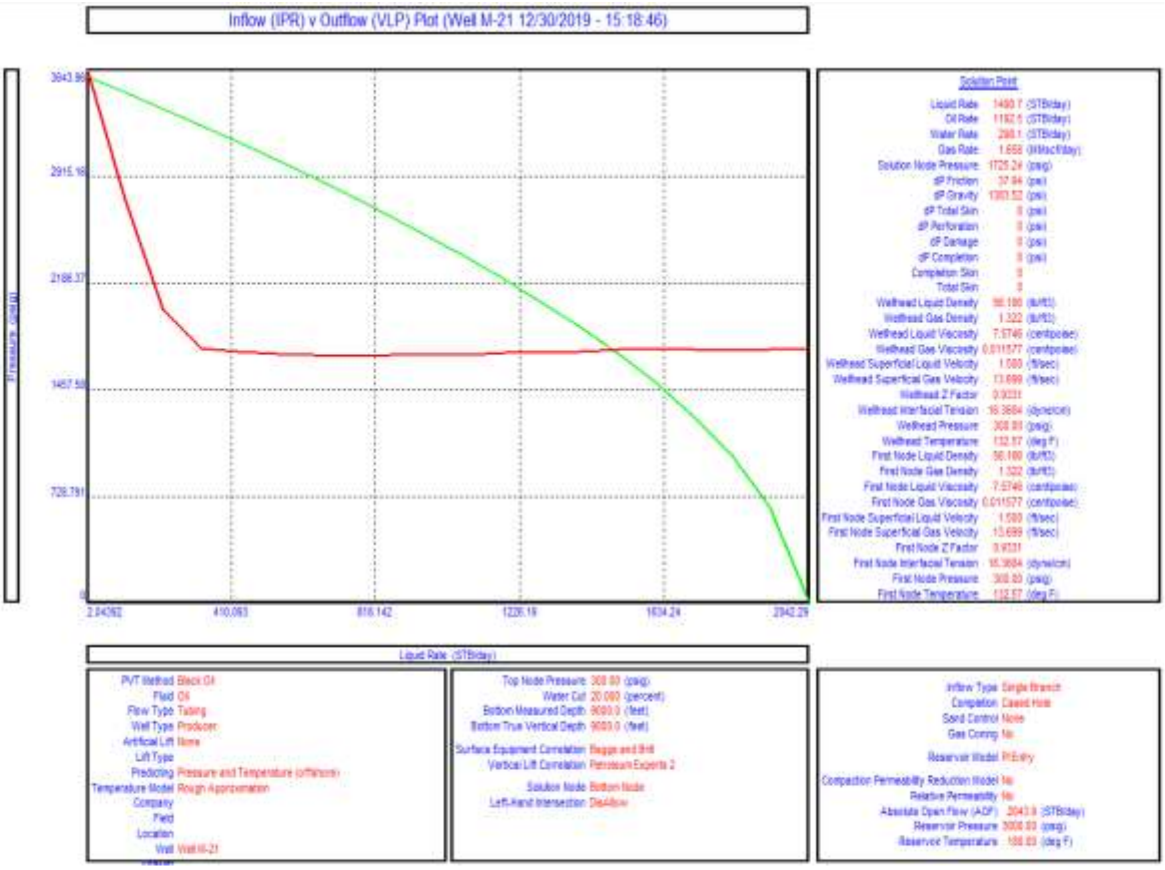

Figure 5.7: Inflow (IPR) versus Outflow (VLP) Plot

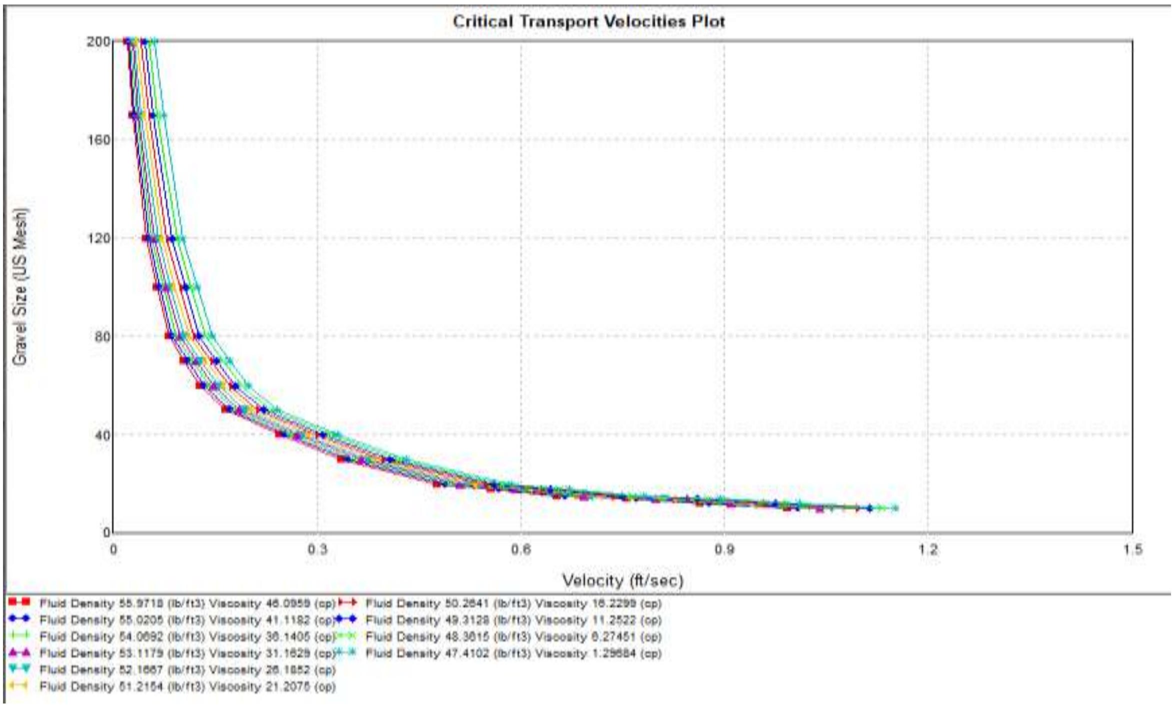

Figure 5.8: The Critical Transport Velocities

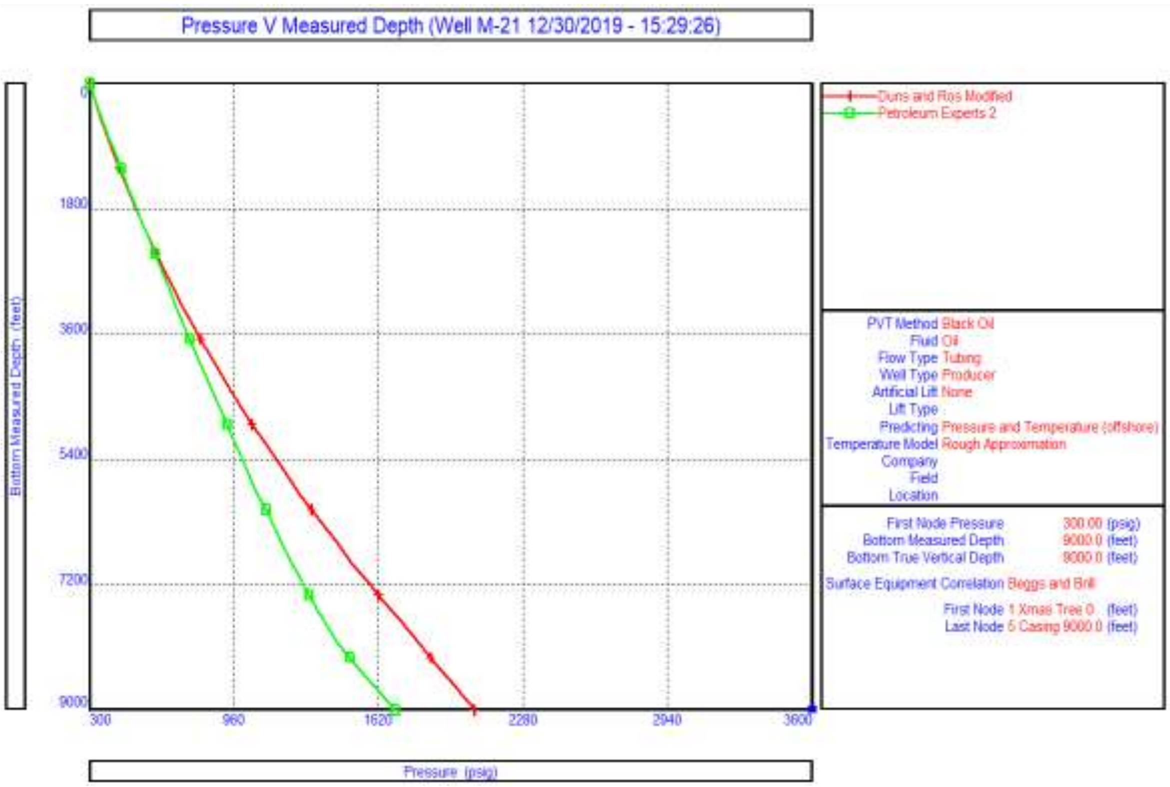

Figure 5.9: Revised Duns and Rons Bottom Measured Depth vs Pressure

5.3 Optimal Well Design by using PIPESIM

Achieving an optimal well design is very key to maximizing production over the life of a well. The PIPESIM simulator enables engineers to analyse the key parameter that would influence overall well performance using the vital nodal analysis technique. The interactive well schematic appears on the left and well components; such as tubing, casing or chokes etc. can be dragged in place. In the first step a casing is dragged and attached to the wellhead, after which the tubing is added. The deviation is left on default since a vertical well is needed; the soil temperature at the wellhead is specified from the heat transfer tab. A fluid is created by going into the fluid tab and selecting a particular type of fluid. A well design schematic for M-21 was completed using the data provided for optimal well performance with knowledge of the fluid contacts and depth to the formation top as seen in Figure 5.10 below.

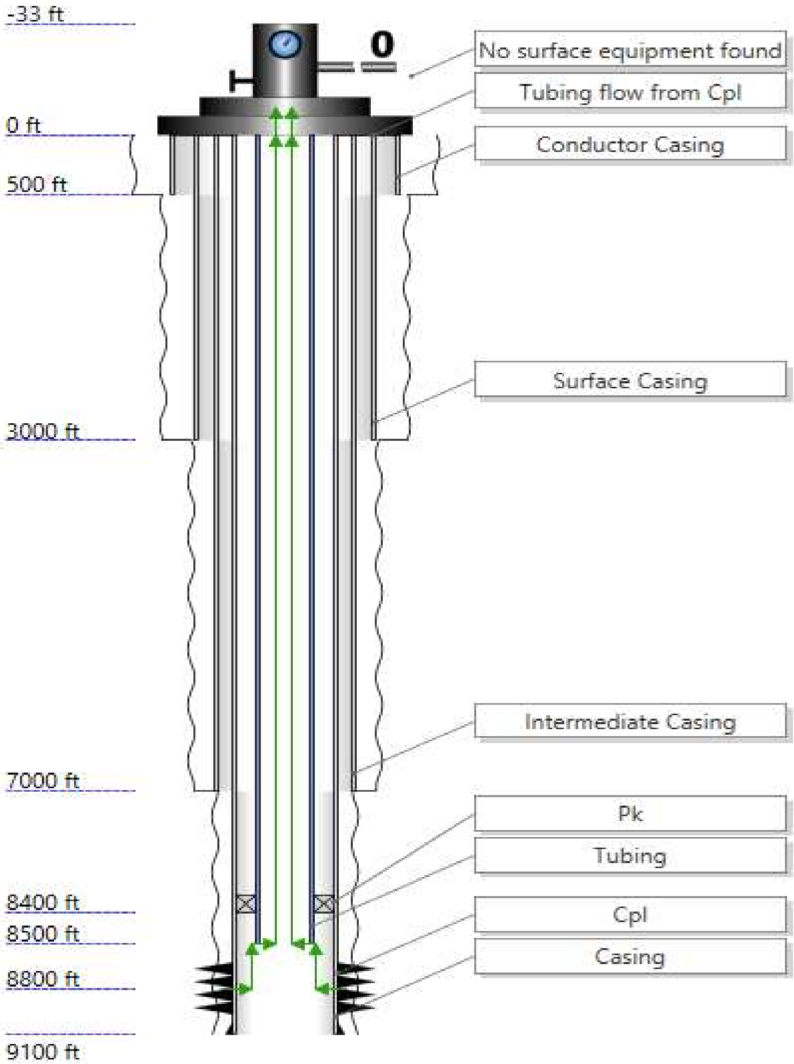

Figure 5.10: PIPESIM Well M-21 Schematic

After building and completing the well, a nodal analysis will be run; nodal analysis determines how much production can be achieved i.e. the well deliverability. The PIPESIM simulator for changes in fluid behaviour, pressure losses across the flow path and heat transfer with the surroundings enables the user to sensitize on various inflow and outflow parameters to optimize the well performance.

Before launching the nodal analysis task or any task on PIPESIM, it is necessary to see if there are any validation issues on the validation centre and be sure it is resolved before attempting to run or launch the simulation. In the home tab at the top, a nodal analysis task will be selected but before the launch button appears a nodal analysis location needs to be specified. After running the nodal analysis, an inflow and outflow curve is produced as shown in Figure 5.11. The inflow and outflow curve show approximately 2000 stb/d at 1600 psi and is considered to be the pressure at which the well would begin to flow again.

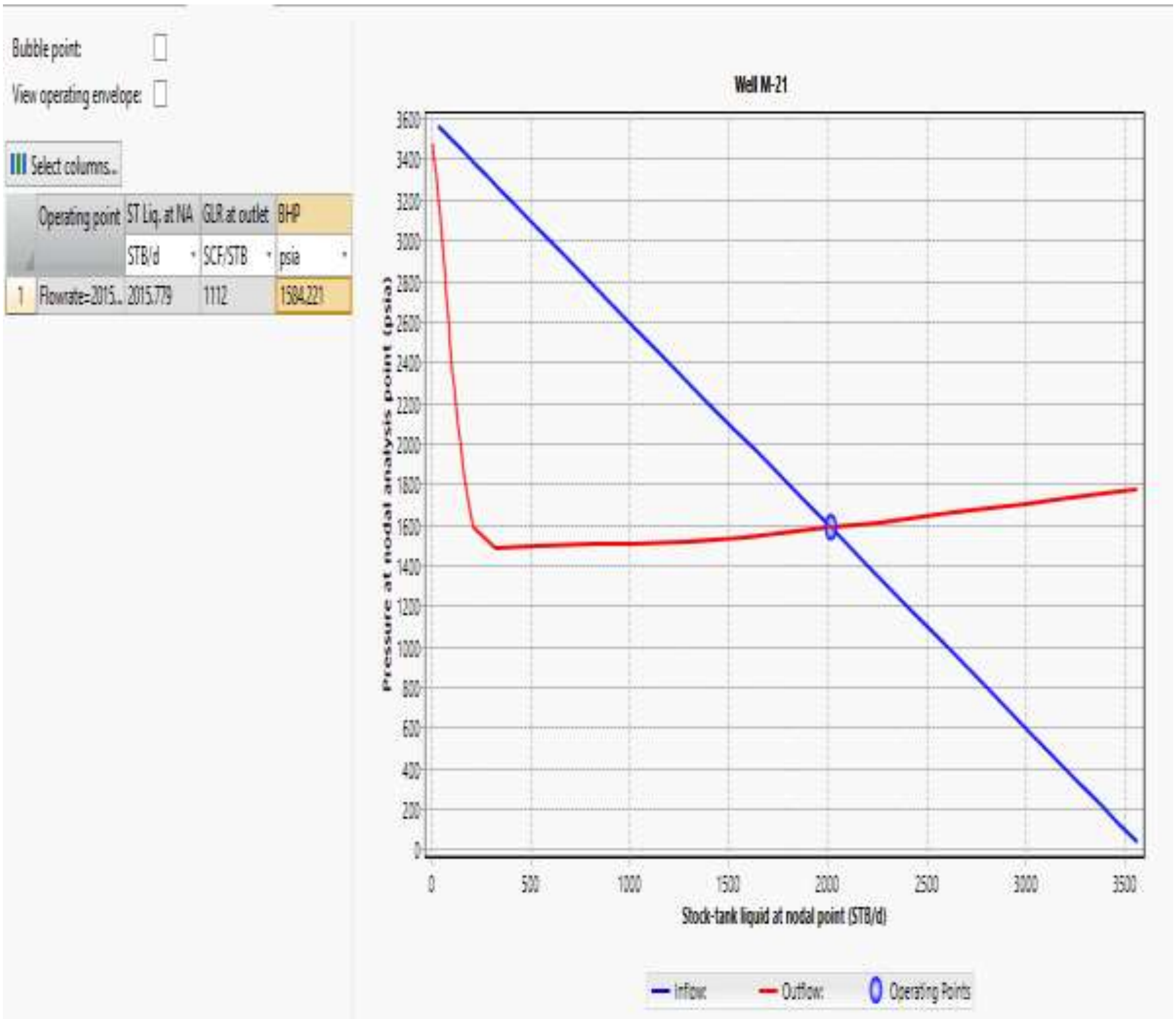

Figure 5.11: Inflow versus Outflow Plot

The profile results can be viewed in tabular or grid format and can also be customised for adding or removing any variable of interest. Different parameters affect the operating point, some of which are located within the inflow such as reservoir pressure, productivity index while others are in the outflow such as the well head flowing pressure and tubing size. The flowing profile variables i.e. the flowing pressure and temperature holdup from the reservoir to the surface corresponding to the operating point flowrate can be seen in Figure 5.12.

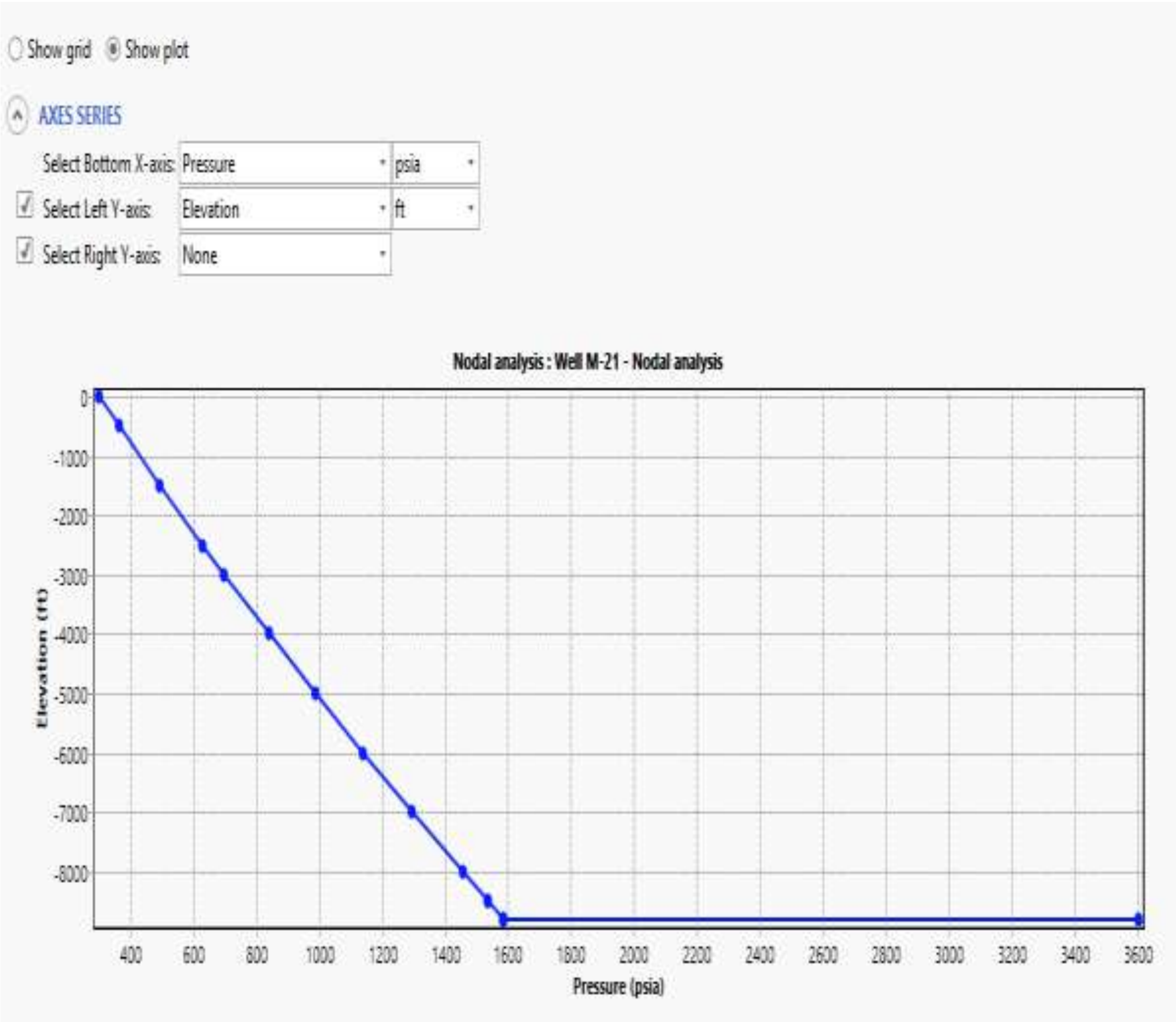

Figure 5.12: Flowing Pressure Profile

5.4 Result and Discussion

Sensitivity analysis on any of the inflow and outflow parameters can show their impacts on the well performance, for instance; sensitivity analysis has determined that when the reservoir pressure declines to 3200 psi the well will stop flowing at 40% water cut shown in Figure 5.13. Therefore; there will be an option of installing ESP to maintain the well production when the reservoir performance drops.

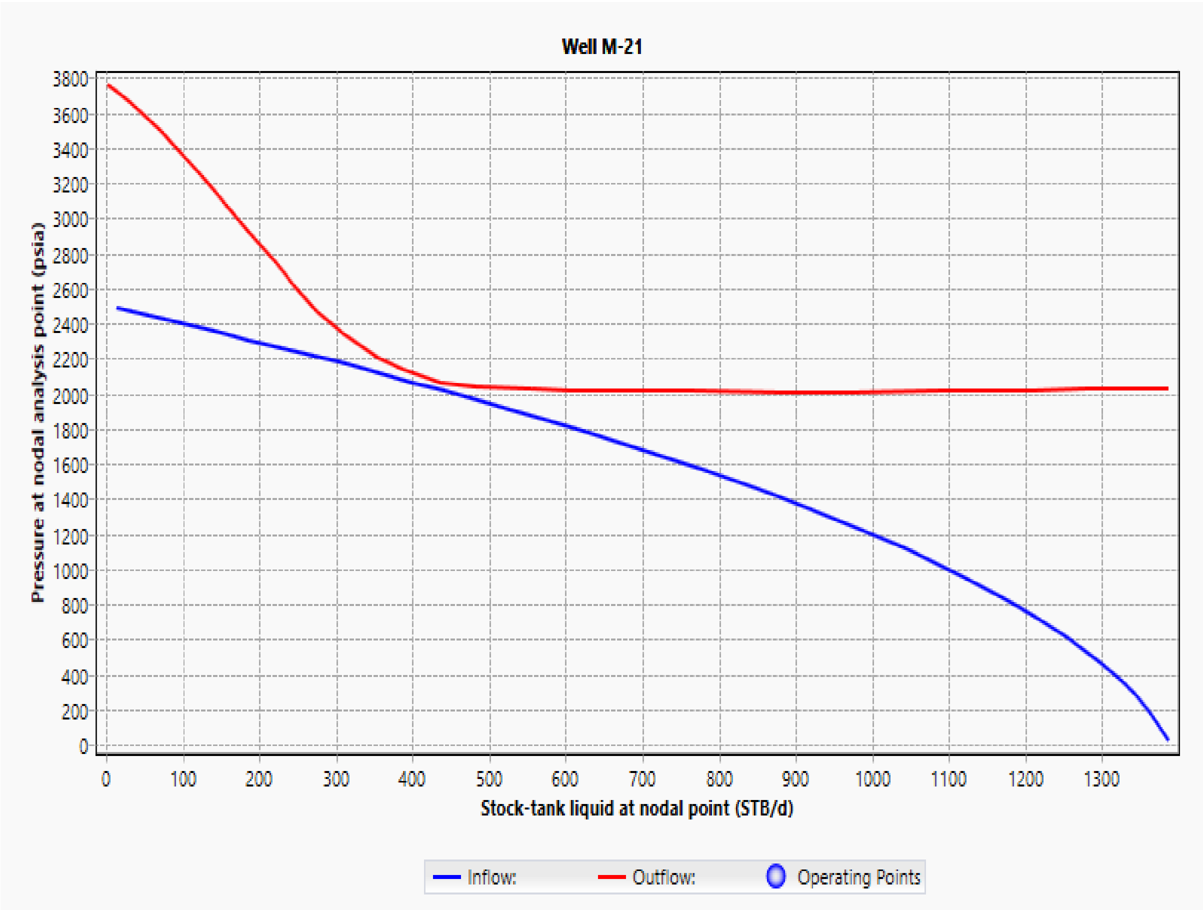

Figure 5.13: Inflow versus Outflow at 40% Water Cut and 3200 psi

A specific ESP is added to the well at the tubing depth (8450 ft), an ESP selected from the catalogue shows it can deliver a target flowrate of 2000 stb/d. The catalogue is also filtered to accommodate an ESP that matches the casing inner diameter. The recommended ESP pump are also ranked in decreasing order of the pump efficiency and the ESP model of DN1800 is selected which is the most efficient for the minimum production of 1000 stb/d. In Figure 5.14, a modified well schematic for M-21 is shown with an ESP installed, with its performance and variable speed curves for the selected ESP is shown in Figure 5.15.

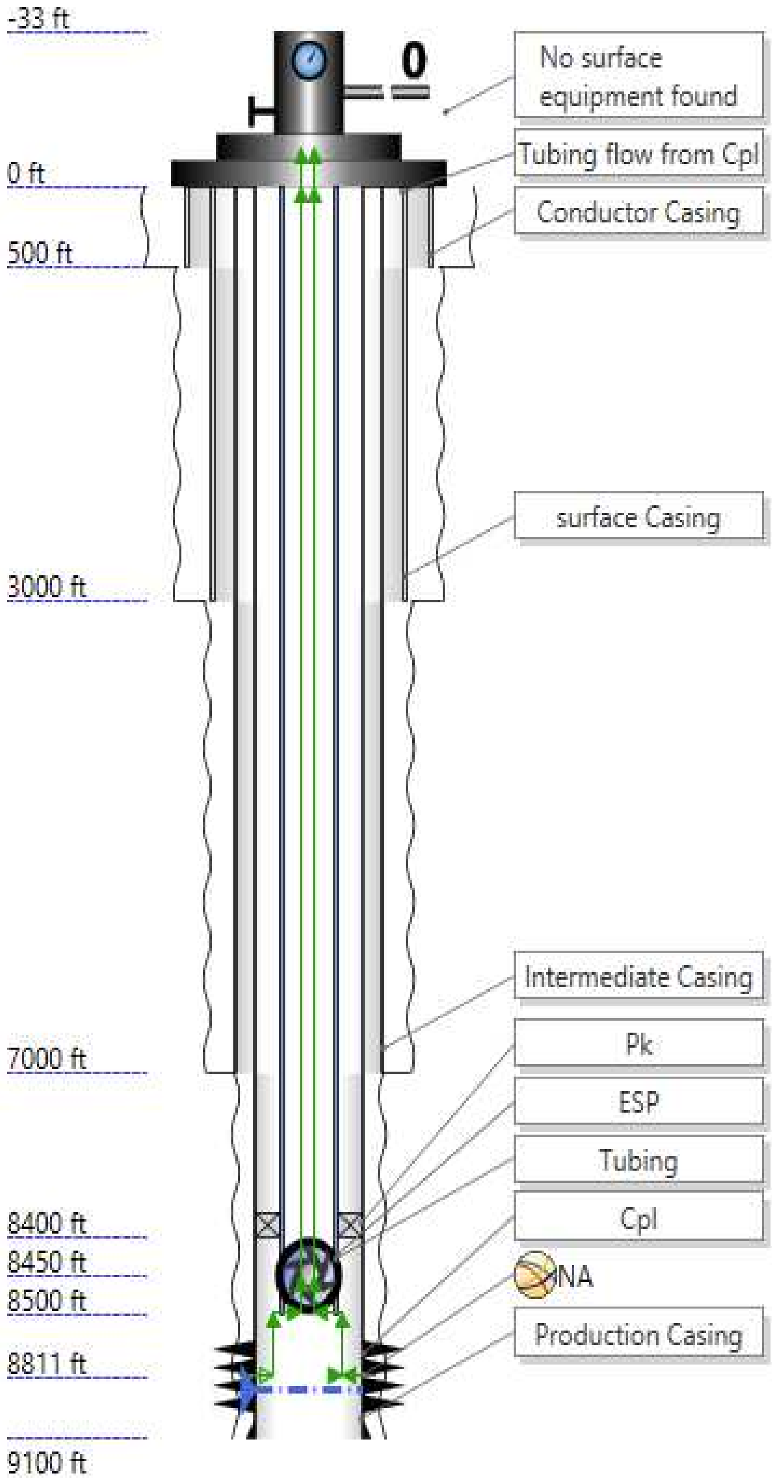

Figure 5.14: Well M-21 Schematic with ESP installed

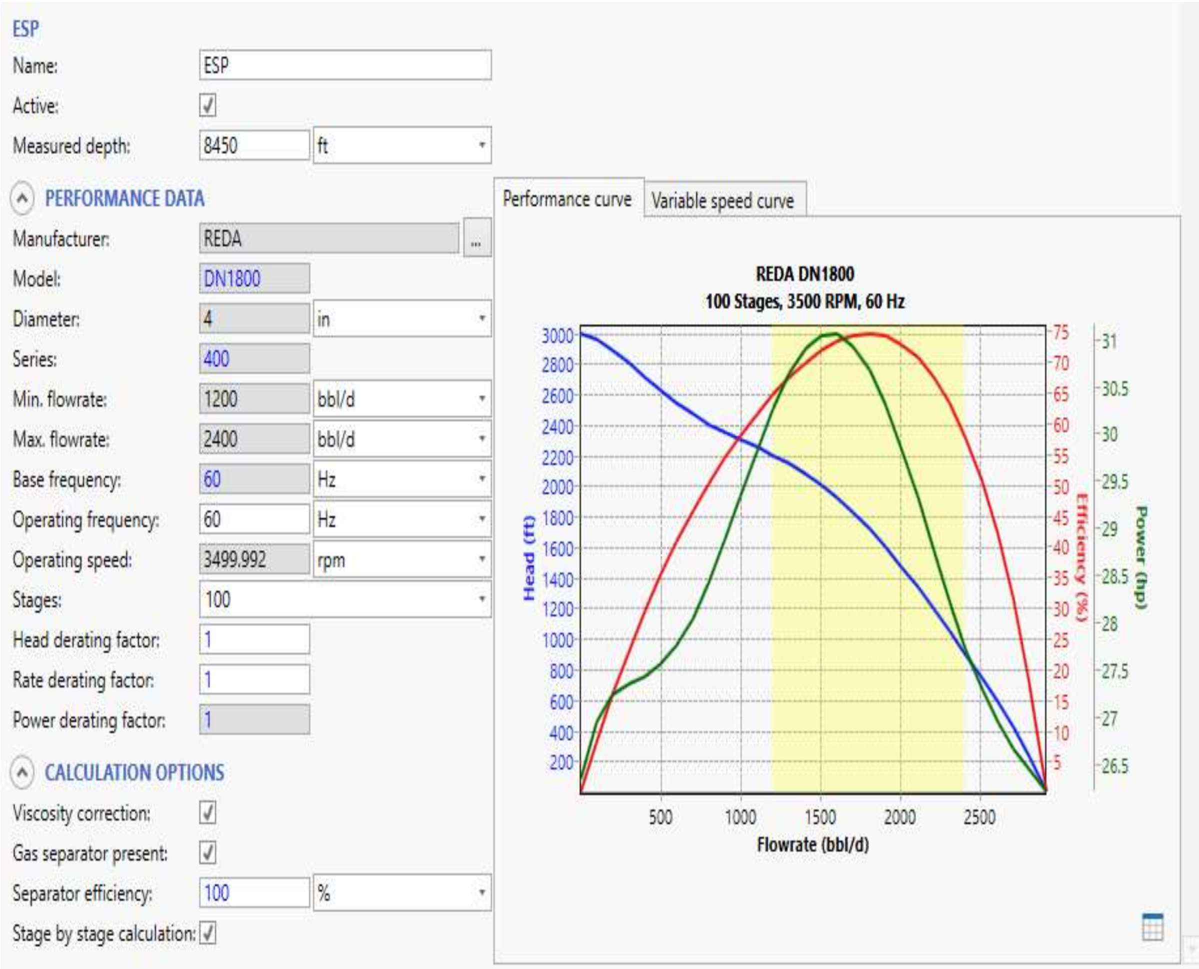

Figure 5.15: ESP Performance Curve

A hundred pump stages have been pre-populated but it is important to know that it might be insufficient to deliver the target rate of 1000 stb/d. The ESP design task will be run to be able to determine the number of stages required to deliver the target rate. The viscosity correction which is based on water is applied; a gas separator is added as a component to the ESP since there is a high gas volume in the reservoir.

A nodal analysis will be run again after the ESP has been installed, to evaluate the impact of the ESP by configuring a sensitivity of the frequency 0 Hz for the scenario without the pump and 60 Hz with the pump on. Figure 5.16 shows how installing an ESP would once again induce flow in the well.

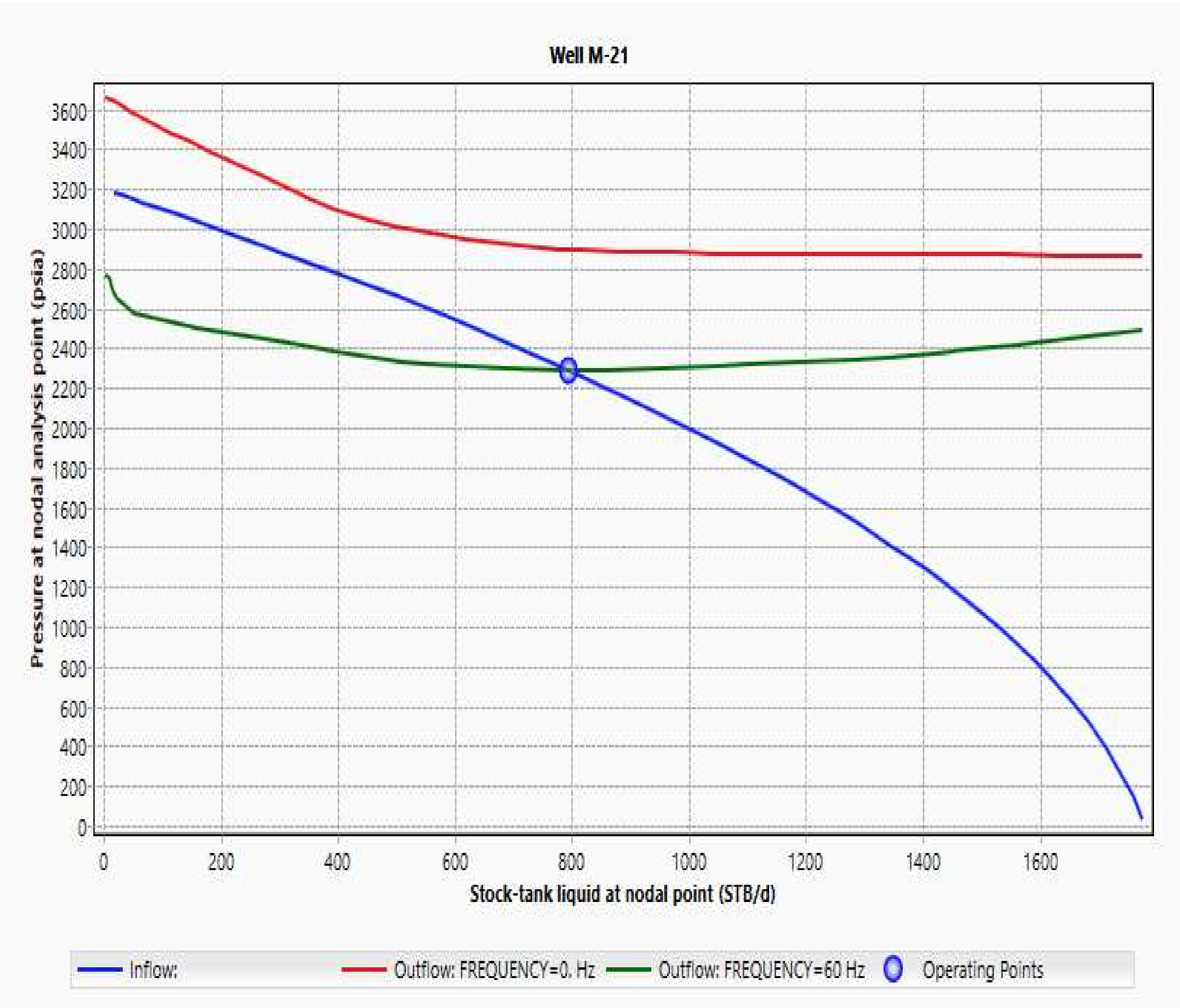

Figure 5.16: The ESP Effect on Inflow versus Outflow

The system result appears and as previously determined without the ESP the well is dead, while the benefit of the ESP is clearly seen as it enables the well to produce at a rate of 795stb/d using a hundred ESP pump stages. In order to deliver the target rate of 1000 stb/d more stages need to be added.

PIPESIM is one of the several workflows that can be used to design, evaluate and optimize a well, through nodal analysis the PIPESIM steady-state multi-phase flow simulator enables and helps engineers to understand well performance so they can design and optimize wells to ensure maximum deliverability.

CHAPTER 6

CONCLUSION AND RECOMMENDATIONS

6.1 Conclusion

This study comprises of concepts detailing the generation of a valid model using a single well drilled in the middle and simulated at different production oil rates. The results garnered shows how each field parameter changes with applied scenarios over the course of this study. The introduction of well performance programs was done to communicate the importance of selecting suitable well variables, prediction of well performance and improvement techniques.

Listed below are the important remarks established at the end of this study.

1. As seen in Chapter 4 on a graph plot of rate versus water cut, the effect of waterflooding at a rate of 5000 stb/day reduces the breakthrough time of water.

2. By comparing simulated results for the layers, a clearer distinction on what layer can produce at a higher rate can be achieved.

3. Water injection in the farthest block i.e. in the 10^{th} layer sweeps oil in the nearby zones but not nearly enough to push oil from the other end of the reservoir.

4. The gas production rate increases as the oil rate begins to decline from the 285^{th} day, indicating a gas coning problem.

5. From the 720^{th} day the WOR declines gradually and the GOR drops because of the sudden one hundred barrels per day production of oil, the expected production of water should be high.

6. The performance of the well was achieved using PIPESIM analysis. Engineers find it helpful in understanding the effect of a well in other to guarantee the best deliverability of the well.

7. Decline in well performance is caused by the reduction of reservoir pressure as seen in PROSPER.

6.2 Recommendations

From the highlighted conclusions above, some improvement suggestions are as follows:

1. The use of two injection wells at opposite end of the reservoir may provide better oil sweep. The downside is that the time to breakthrough for water will be shorter.

2. The use of ESP can be employed downhole at the WOC depth to draw out most of the water, providing easy access for more oil production. This approach is recommended if the water encroachment is not unlimited i.e. small aquifer

3. The use of ESP may be used to revive the well with a declining reservoir pressure and high water cut. An example is with the use of simulation tool i.e. PIPESIM, a scenario was presented with water cut increased from twenty to fifty percent, and the reservoir pressure was to 3200 psi. In this scenario, the well stopped producing but by placing an ESP at the tubing depth the well began flowing with a production rate of about800 barrels per day.

4. The BHP can be lowered to reduce the gas and water being produced due to the pressure difference.

5. Layers nine and ten has a relatively better permeability and porosity. Since this area was found to have the highest oil rate without an injection well, therefore this is the best zone suggested to be completed.

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APPENDICES

APPENDIX A

DATASET REPRESENTATION

The input data produced graphs showing the state of the reservoir and pressure distribution throughout the formation. An exact replica of the gas formation factor, gas expansion and gas compressibility distribution with pressure is shown. The relative permeability distribution for liquid and gas phase can be seen as well as how they interchangeably perform with capillary pressure for oil-water and gas-oil respectively. A schematic representation of Well M-21 model is given in Figure A1.

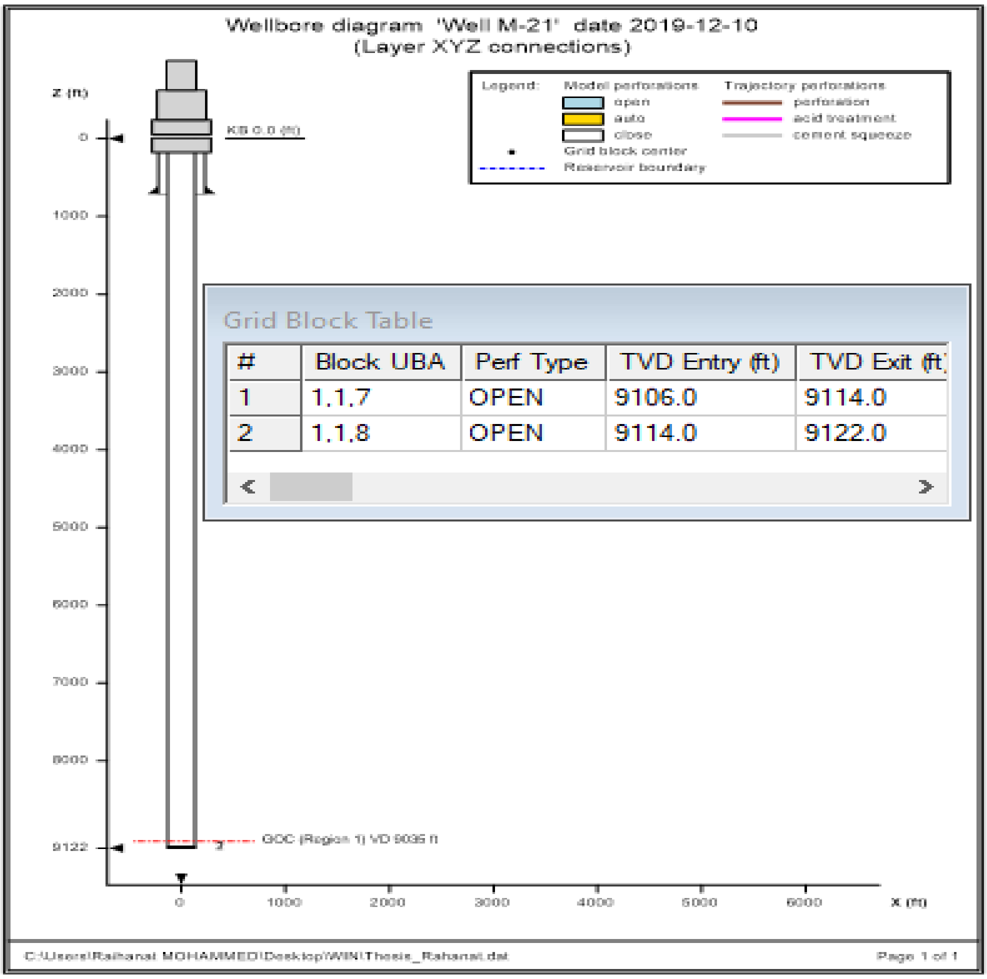


Figure A1: Showing schematic model for well M-21

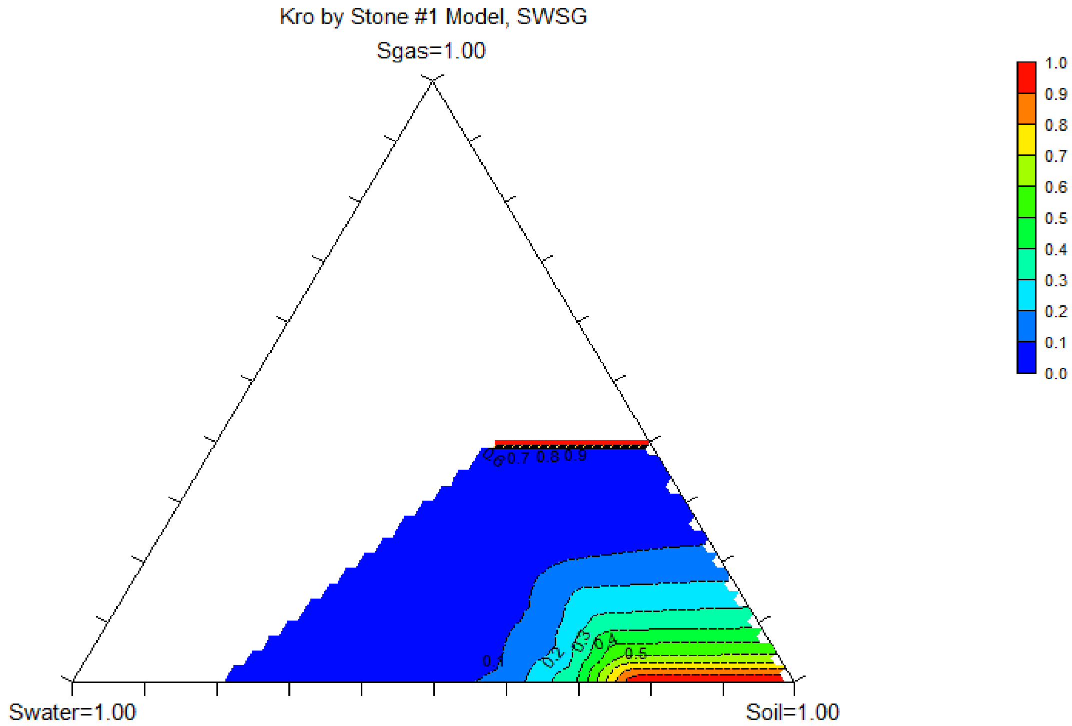


Figure A2: Oil relative permeability (Kro) model for SWSG.

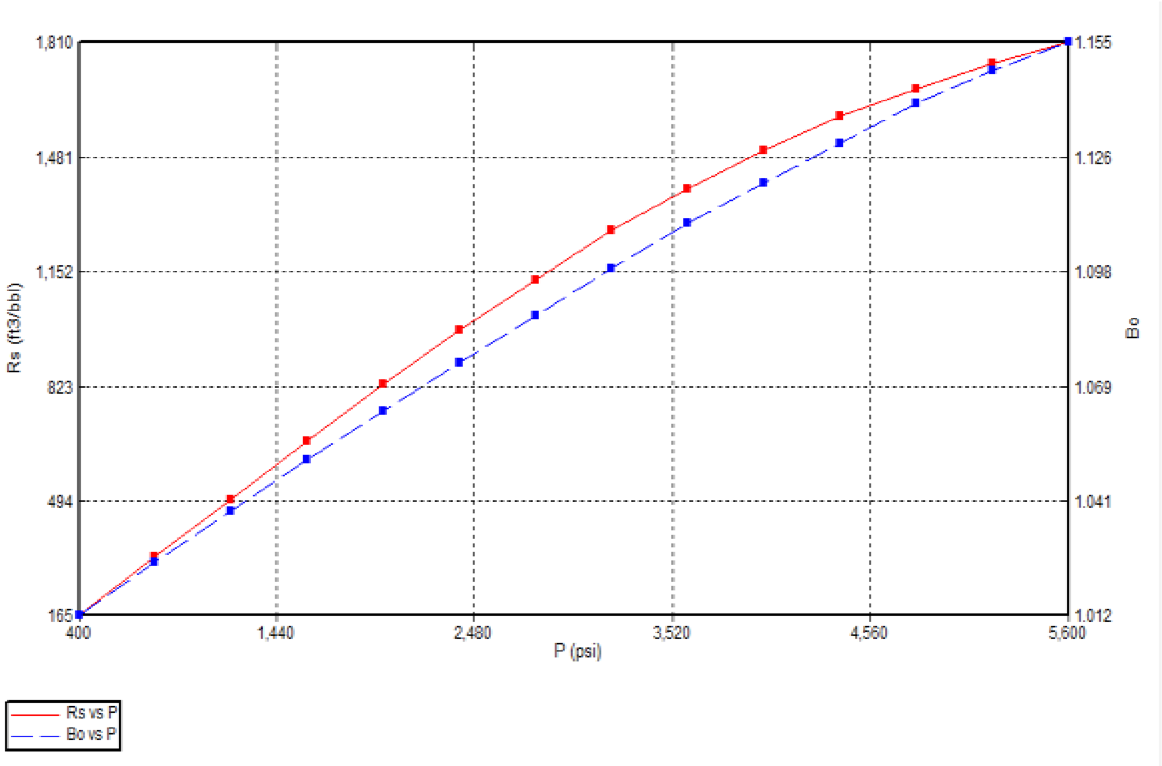


Figure A3: Solution gas (Rs) and oil formation factor (Bo) vs Pressure.

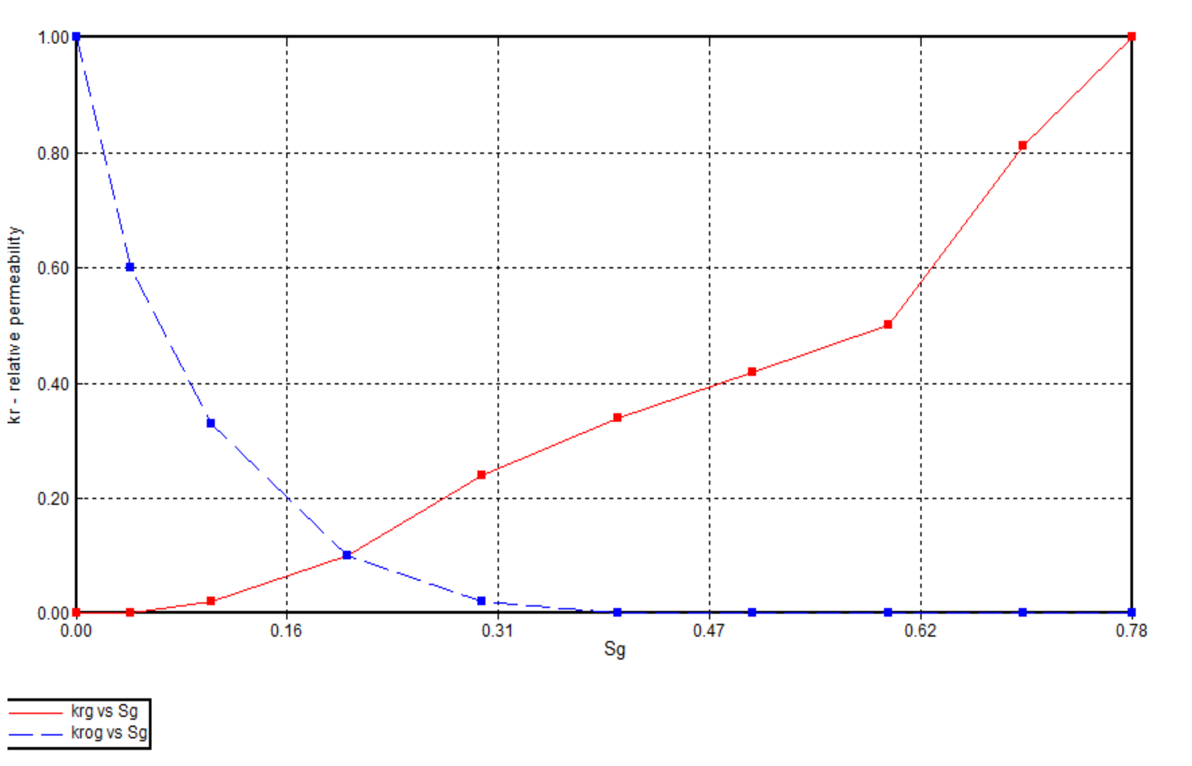


Figure A4: Showing relative permeability vs gas saturation

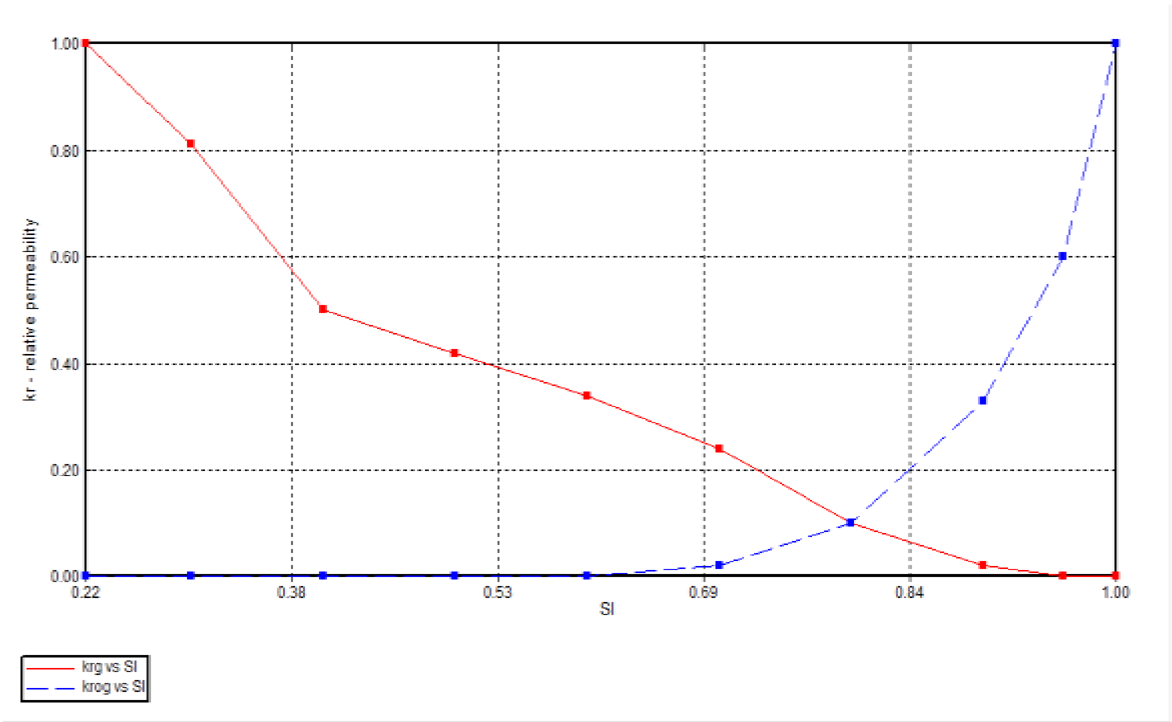


Figure A5: Relative permeability vs liquid saturation

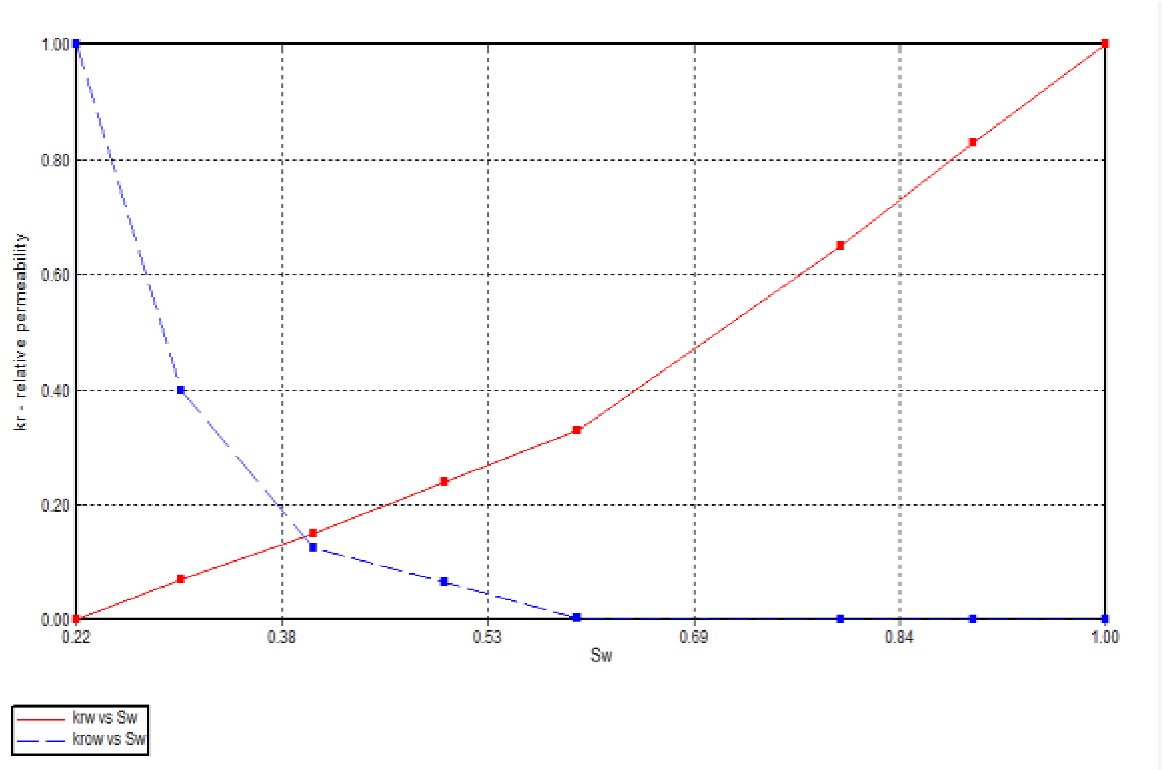


Figure A6: Relative permeability vs water saturation

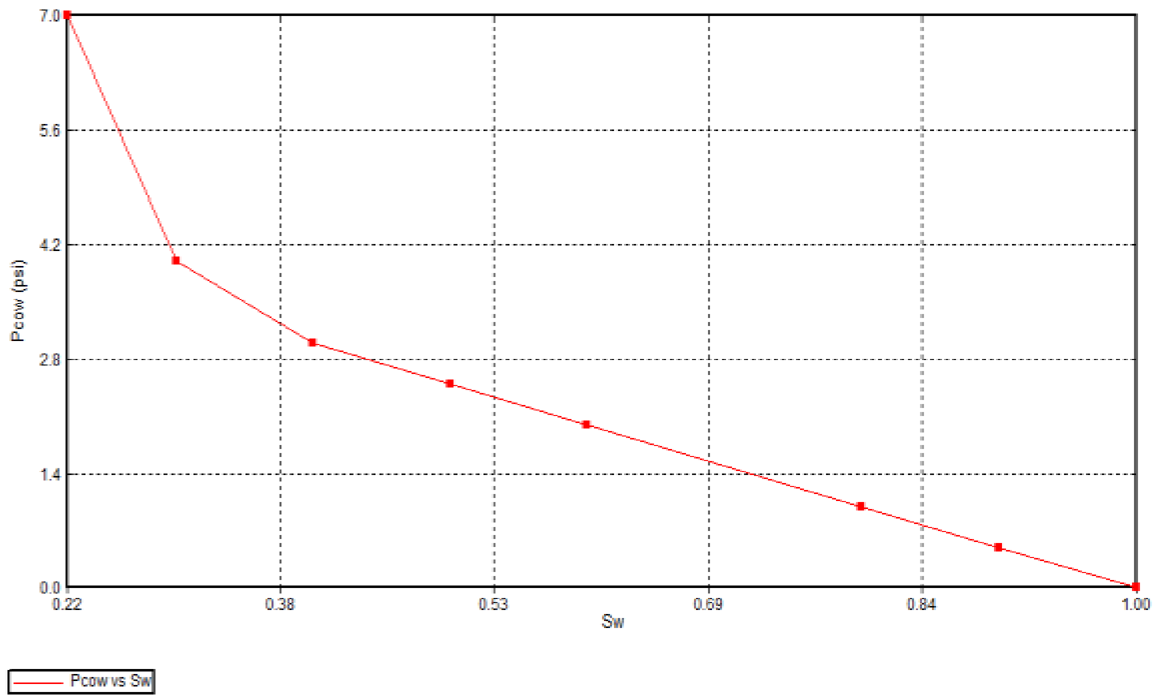


Figure A7: Showing Pcow vs Sw

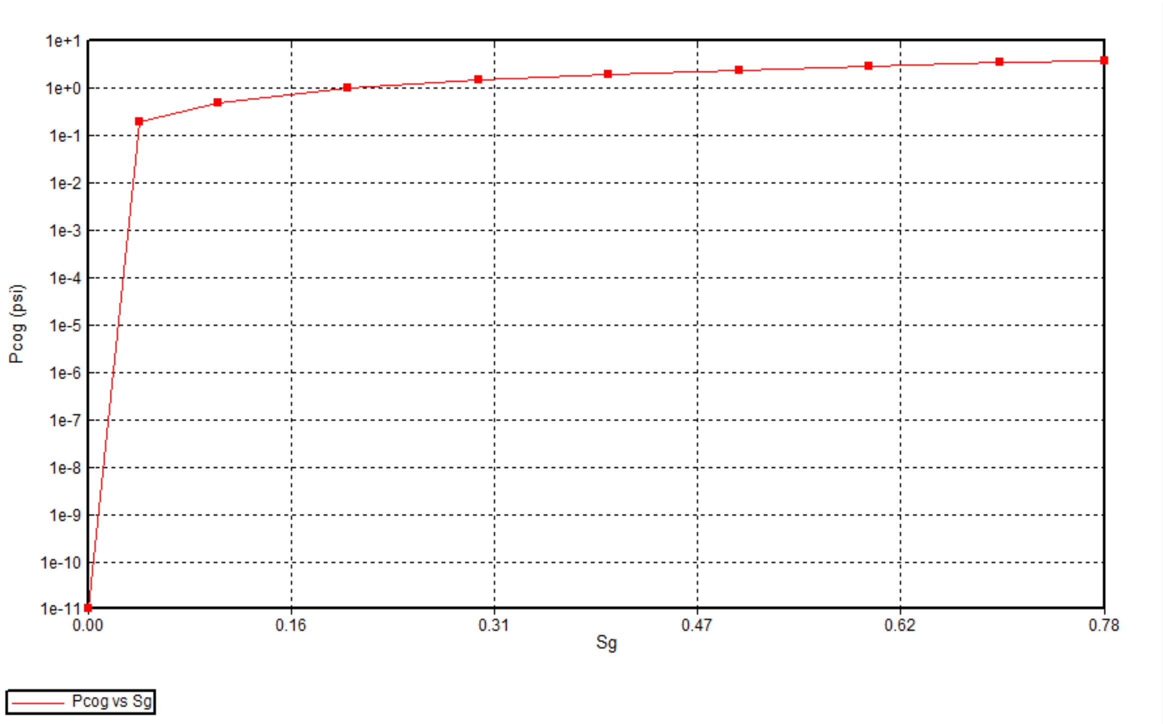


Figure A8: Showing Pcog vs gas saturation

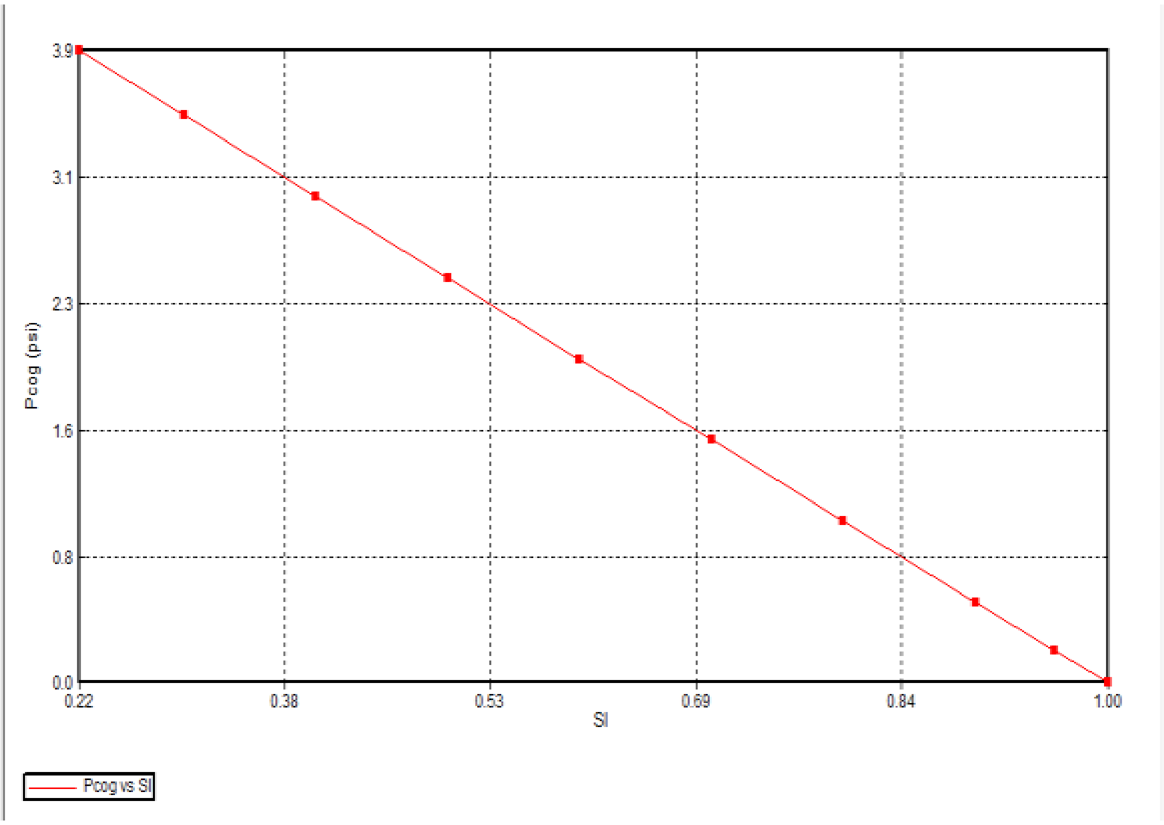


Figure A9: Pcog vs liquid saturation

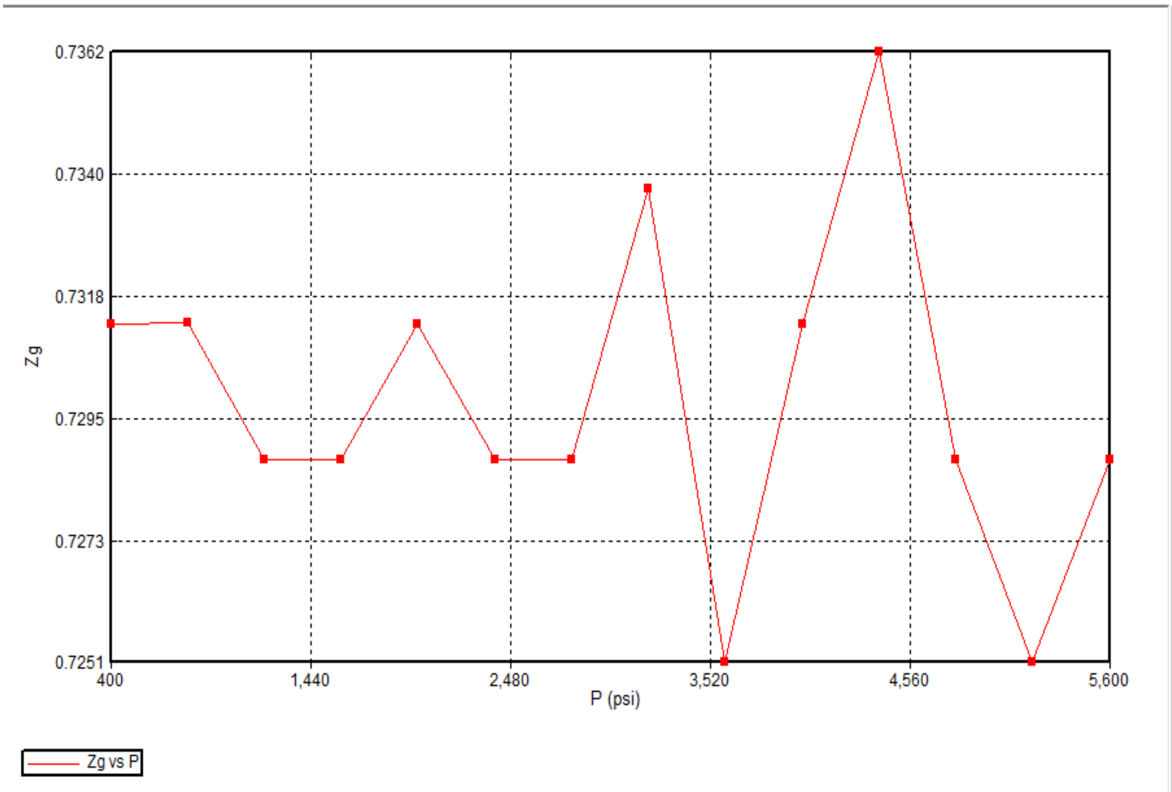


Figure A10: Showing gas compressibility vs pressure

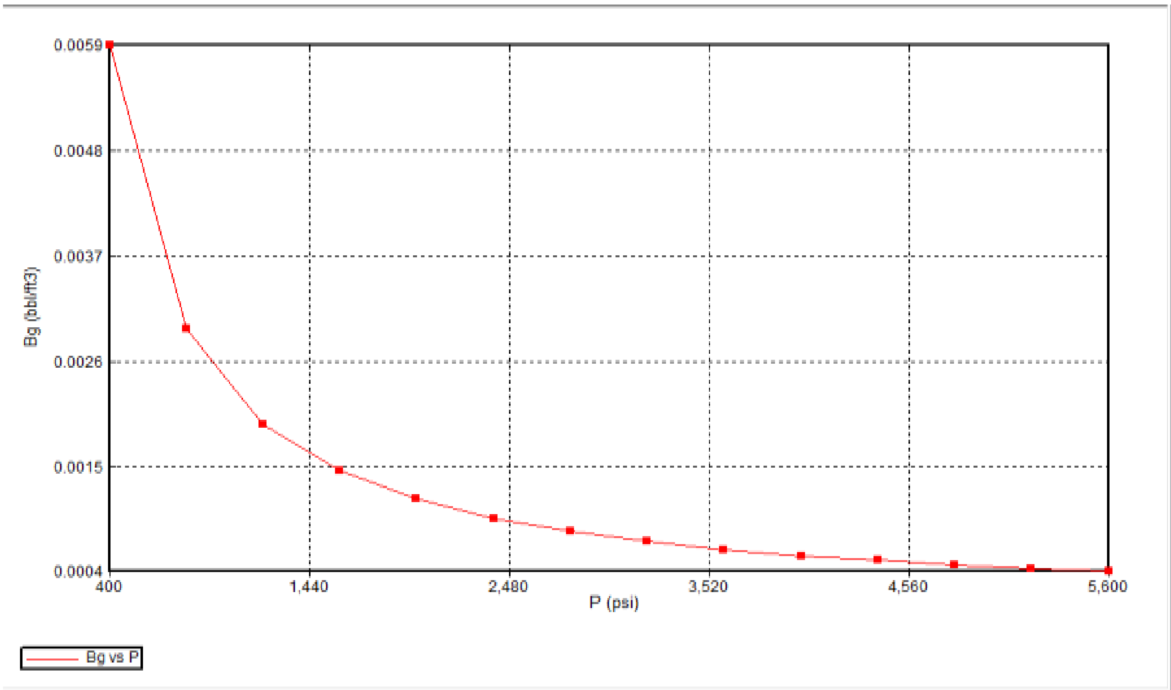


Figure A11: Gas formation factor vs pressure

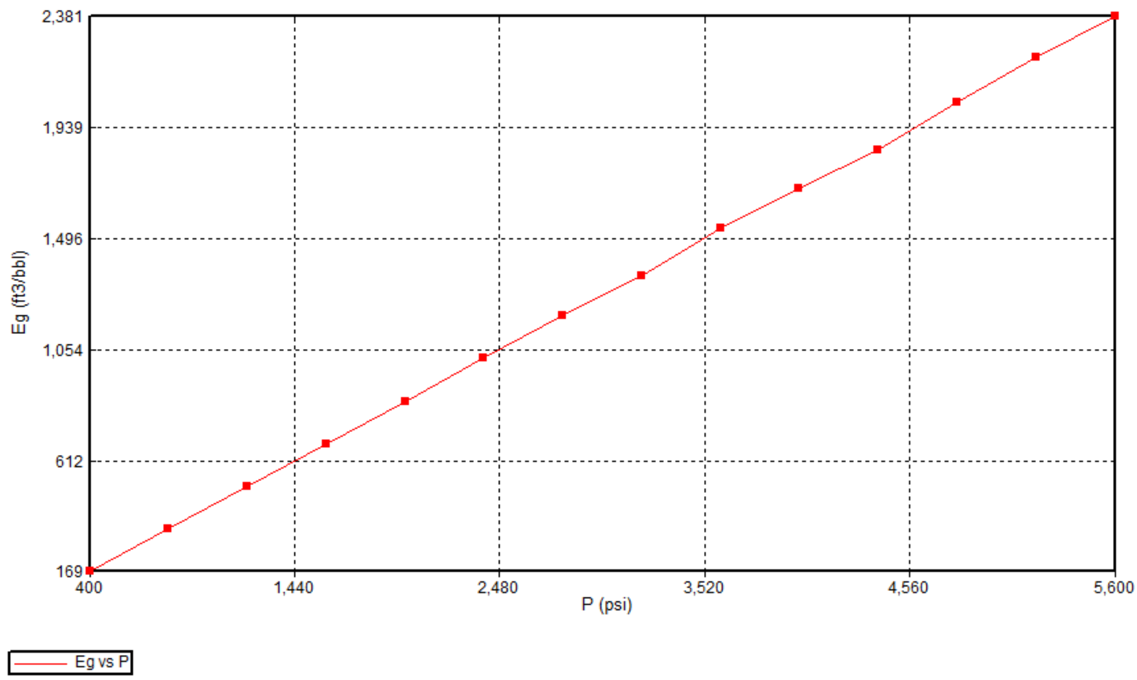


Figure A12: Gas expansion vs pressure

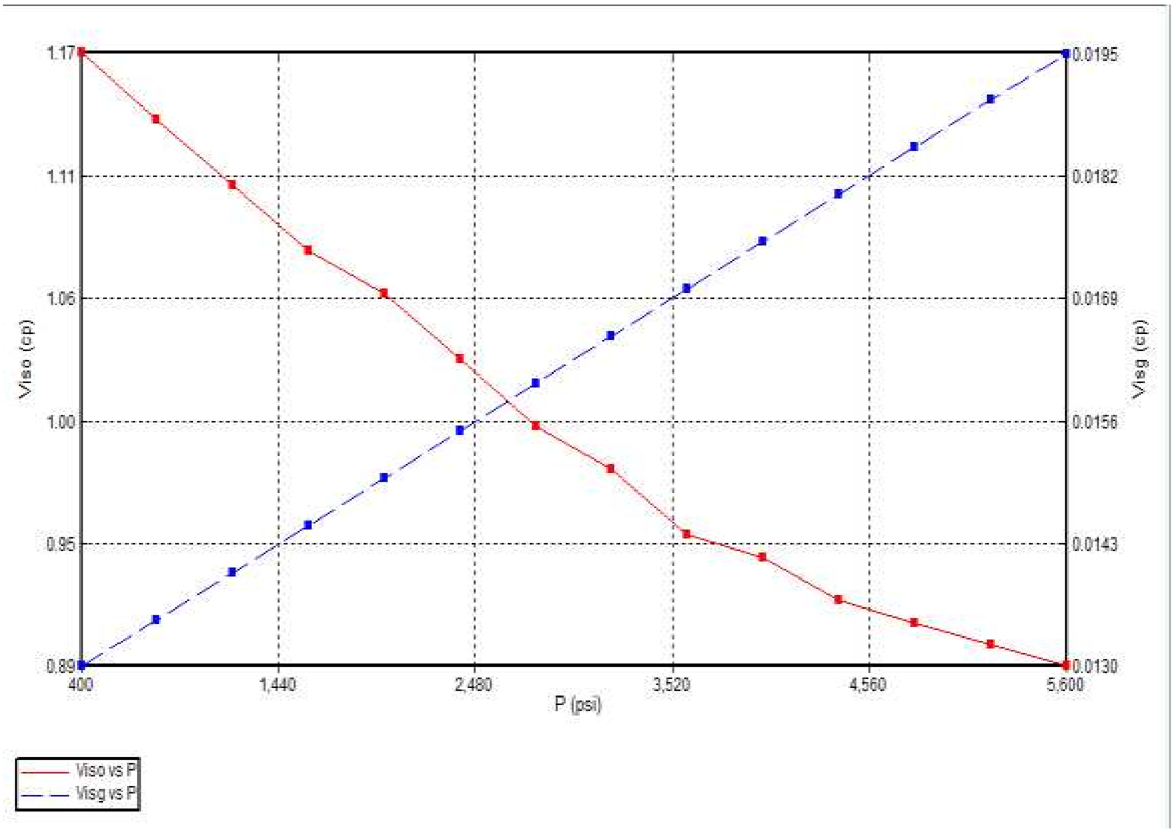


Figure A13: Showing viscosity of oil and gas vs pressure

APPENDIX B

3-D RESERVOIR MODEL

Reservoir 3-D figures for the radial (cylindrical) grid are profiled showing porosity, water saturation and grid thickness distribution respectively as given in the initial data from Chapter 4.

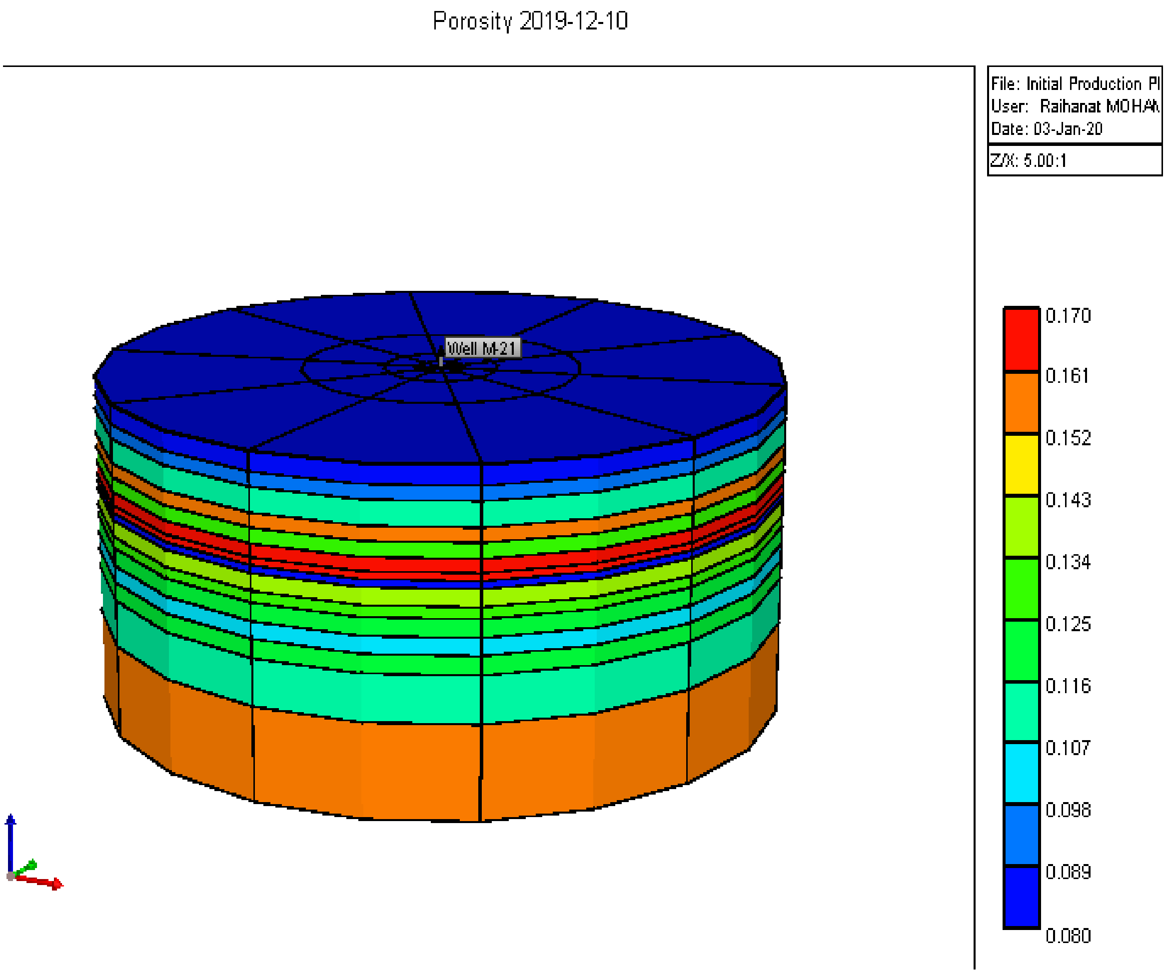


Figure B1: Showing 3-D for porosity distribution

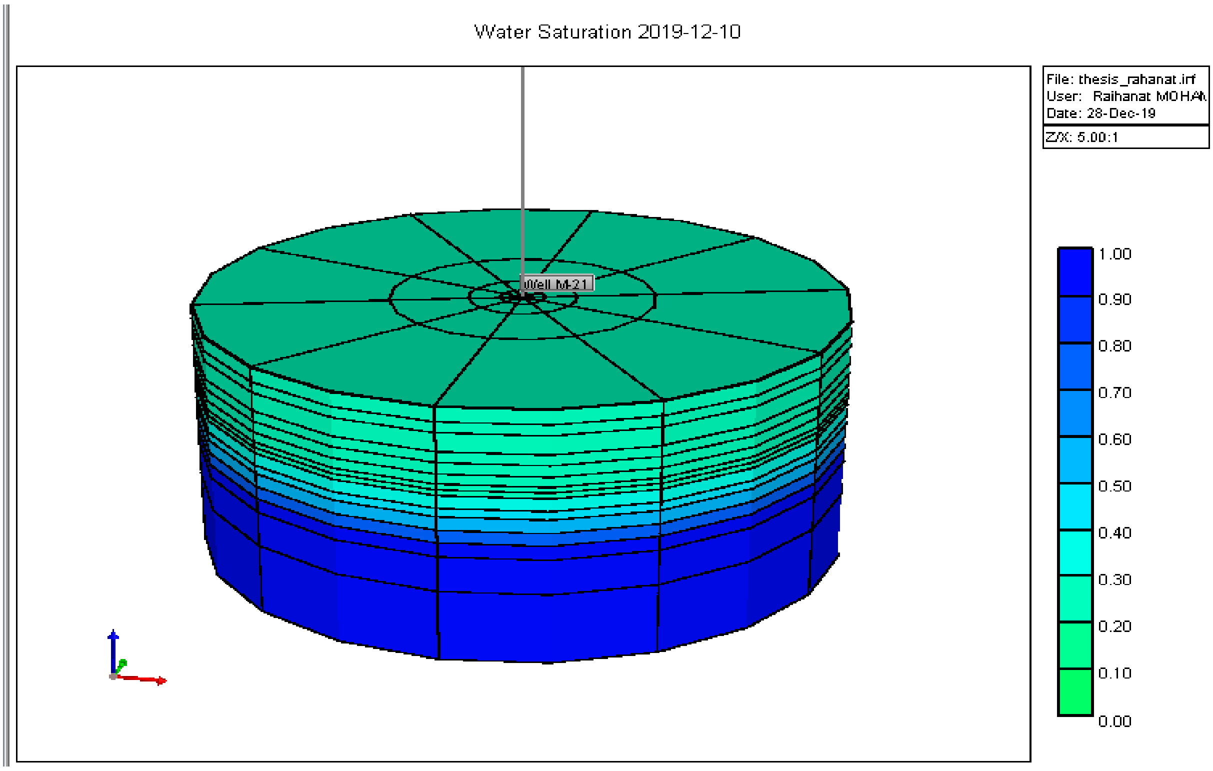


Figure B2: Showing 3-D for water saturation distribution

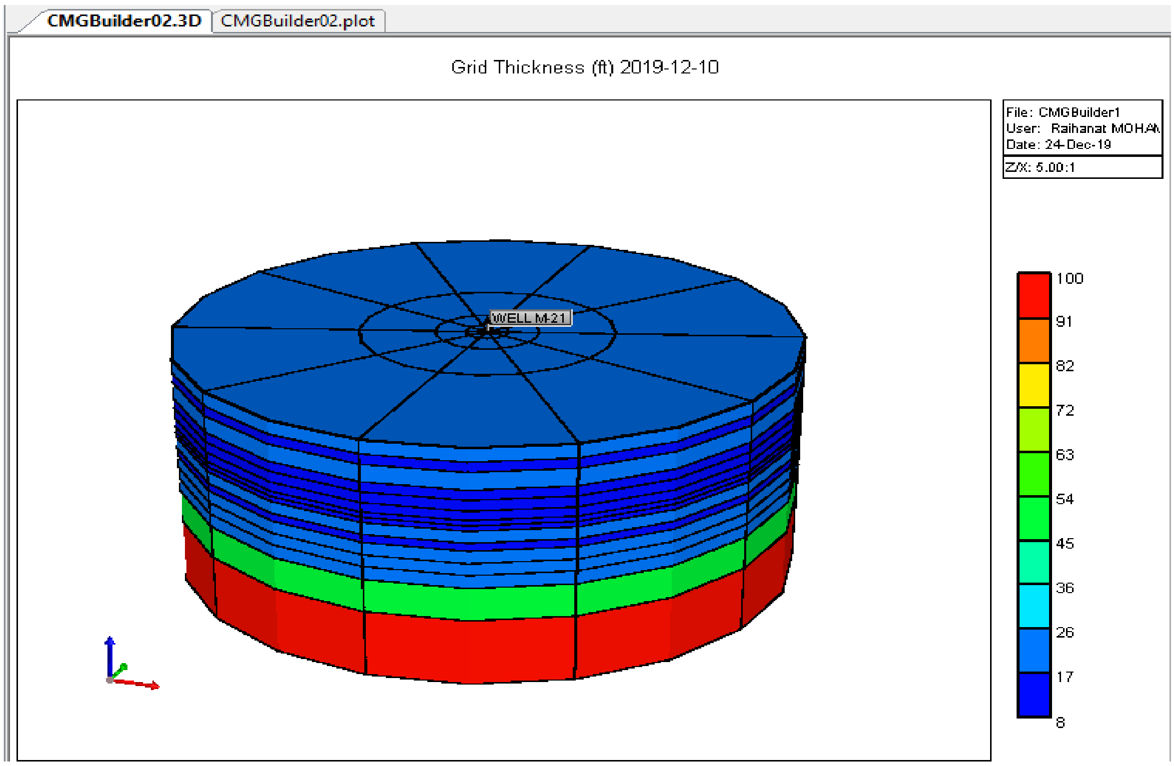


Figure B3: Showing 3-D view for thickness distribution in all 15 layers

APPENDIX C

DATA-FILE FOR CMG MODELLING

RESULTS SIMULATOR IMEX 201410

****

INUNIT FIELD

WSRF WELL 1

WSRF GRID TIME

WSRF SECTOR TIME

OUTSRF WELL LAYER NONE

OUTSRF RES ALL

OUTSRF GRID SO SG SW PRES OILPOT BPP SSPRES WINFLUX

WPRN GRID 0

OUTPRN GRID NONE

OUTPRN RES NONE

** Distance units: ft

RESULTS XOFFSET 0.0000

RESULTS YOFFSET 0.0000

RESULTS ROTATION 0.0000 ** (DEGREES)

RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0

```
**
*****************************************************************************
**
** Definition of fundamental cylindrical grid
**
*****************************************************************************
**
GRID RADIAL 10 10 15 *RW        0.25
KDIR DOWN
 DI IVAR    0.365632    0.90038    2.21721    5.45995    13.4453
            33.1094     81.5329    200.777    494.42     1217.52


 DI JVAR       36          36         36         36         36
               36          36         36         36         36


DK ALL
 100*20 100*15 100*26 100*15 100*16 100*14 200*8 100*18 100*12 100*19
 100*18 100*20 100*50 100*100
DTOP
 100*9000
PERMI KVAR
 35 47 148 202 90 418 775 60 682 472 125 300 137 191 350
** 0 = null block, 1 = active block
NULL CON          1
```

POR KVAR

0.087 0.097 0.111 0.16 0.13 2*0.17 0.08 0.14 0.13 0.12 0.105 0.12

0.116 0.157

PERMJ KVAR

35 47 148 202 90 418 775 60 682 472 125 300 137 191 350

PERMK KVAR

3.5 4.75 14.8 20.2 9 41.8 77.5 6 68.2 47.2 12.5 30 13.75 19.1 35

** 0 = pinched block, 1 = active block

PINCHOUTARRAY CON 1

PRPOR 3600

CPOR 0.000004

MODEL BLACKOIL

TRES 180

PVT BG 1

**	p	Rs	Bo	Bg	viso	visg
	400	165	1.0120	5.90	1.17	0.0130
	800	335	1.0255	2.95	1.14	0.0135
	1200	500	1.0380	1.96	1.11	0.0140
	1600	665	1.0510	1.47	1.08	0.0145
	2000	828	1.0630	1.18	1.06	0.0150
	2400	985	1.0750	0.98	1.03	0.0155
	2800	1130	1.0870	0.84	1.00	0.0160
	3200	1270	1.0985	0.74	0.98	0.0165

3600	1390	1.1100	0.65	0.95	0.0170
4000	1500	1.1200	0.59	0.94	0.0175
4400	1600	1.1300	0.54	0.92	0.0180
4800	1676	1.1400	0.49	0.91	0.0185
5200	1750	1.1480	0.45	0.90	0.0190
5600	1810	1.1550	0.42	0.89	0.0195

DENSITY OIL 45

DENSITY GAS 0.0702

REFPW 14.696

DENSITY WATER 63.02

BWI 1.01303

CW 3e-6

VWI 0.96

CVW 0

PTYPE CON 1

CO 0.00001

CVO 0

ROCKFLUID

KROIL STONE1 SWSG

RPT 1

**	S_w	K_{rw}	K_{row}	P_{cow}
SWT				
	0.22	0.00	1.0000	7.0

0.30	0.07	0.4000	4.0
0.40	0.15	0.1250	3.0
0.50	0.24	0.0649	2.5
0.60	0.33	0.0048	2.0
0.70	0.49	0.0000	1.5
0.80	0.65	0.0000	1.0
0.90	0.83	0.0000	0.5
0.96	0.89	0.0000	0.2
1.00	1.00	0.0000	0.0

** S_g K_{rg} K_{rog} P_{cog}

** S_l K_{rg} K_{rog} P_{cog}

SLT

0.22	1.0000	0.00	3.9
0.30	0.8125	0.00	3.5
0.40	0.5000	0.00	3.0
0.50	0.4200	0.00	2.5
0.60	0.3400	0.00	2.0
0.70	0.2400	0.02	1.5
0.80	0.1000	0.10	1.0
0.90	0.0220	0.33	0.5
0.96	0.0000	0.60	0.2
1.00	0.0000	1.00	0.0

INITIAL

VERTICAL DEPTH_AVE WATER_OIL_GAS EQUIL

```
REFDEPTH 9000

REFPRES 3600

DWOC 9209

DGOC 9035

PB CON          0

NUMERICAL

RUN

DATE 2019 12 10

**

**

WELL  'Well M-21'

PRODUCER 'Well M-21'

OPERATE  MIN  BHP  3000.0  CONT

OPERATE  MAX  STO  1000.0  CONT


**        rad  geofacwfrac  skin

GEOMETRY  K  0.25  0.37  1.0  0.0

    PERF      GEOA  'Well M-21'

** UBA            ff          Status  Connection

   1 1 7          1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
```

1 1 8 1.0 OPEN FLOW-TO 1

*MXCNRPT 1

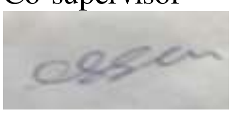
WSRF GRID TNEXT

APPENDIX D

SIMILARITY REPORT

Prof. Dr. Cavit Atalar
Supervisor

Assist. Prof. Dr. Ersen Alp
Co-supervisor



APPENDIX E

ETHICAL APROVAL LETTER

YAKIN DOĞU ÜNİVERSİTESİ

Date: 04/06 /2020

To the **Graduate School of Applied Sciences**

The research project titled "**COMPARATIVE STUDY ON A THREE PHASE SYSTEM FOR THE EVALUATION OF WELL PERFORMANCE AND RESULTS**'' has been evaluated. Since the researcher will not collect primary data from humans, animals, plants or earth, this project does not need through the ethics committee.

Title: Prof. Dr.

Name Surname: Cavit ATALAR

Signature:

Role in the Research Project: Supervisor

Title: Assist. Prof. Dr.

Name Surname: Ersen ALP

Signature:

Role in the Research Project: Co-Supervisor